Scientific Contributions Oil & Gas, Vol. 48. No. 3, October: 23 - 36

SCIENTIFIC CONTRIBUTIONS OIL AND GAS
Testing Center for Oil and Gas
LEMIGAS

Journal Homepage:http://www.journal.lemigas.esdm.go.id
ISSN: 2089-3361, e-ISSN: 2541-0520

Investigation and Optimization of Enhanced Oil Recovery Mechanism By Sophorolipid Biosurfactant in Carbonate Reservoir

Indah Widiyaningsih[1,2], Harry Budiharjo Sulistyarso[2], Ivan Kurnia[1], Taufan Marhaendrajana[1], and Tutuka Ariadji[1]

[1]Department of Petroleum Engineering, Institut Teknologi Bandung
Ganesha Street No. 10 Bandung, Indonesia.

[2]Department of Petroleum Engineering, UPN Veteran Yogyakarta
Padjajaran Street No.104 Yogyakarta, Indonesia.

Corresponding author: tutukaariadji@itb.ac.id

Manuscript received: June 10th, 2025; Revised: June 25th, 2025
Approved: June 30th, 2025; Available online: October 06th, 2025; Published: October 06th, 2025.

ABSTRACT - The Remaining Oil in Place (ROIP) in carbonate rock reservoirs is often substantial due to the tendency of carbonate rocks to be oil-wet in terms of wettability. The oil inherent property of wetting the rock causes the residual oil to adhere to the rock pores, making it challenging to extract to the surface. One method to enhance oil recovery (EOR) is through biosurfactant injection, i.e., sophorolipid, a fungal biosurfactant that possesses the properties of surfactants in general. This study aims to evaluate the effectiveness of sophorolipid biosurfactant injection in enhancing oil recovery in carbonates, as well as to identify the dominant mechanism at work during the injection process and optimize it through coreflooding simulation. This research combines laboratory testing and simulation, comprising two phases: coreflooding experiments and coreflooding simulations. Coreflooding simulation reduces the need for coreflooding experiments, which are both time-consuming and costly. The study uses CMG-STARS with a sensitivity parameter and optimization using CMOST. Sobol Analysis assesses the sensitivity parameters and determines the dominant mechanism of sophorolipid. Optimization is achieved by adjusting the parameters, such as sophorolipid concentration, pore volume (PV) injection, and injection rate. Coreflooding sensitivity results indicate that the dominant parameter is the nonwetting trapping number (DTRAPN), which is closely related to the mechanism of wettability alteration and mix viscosity. Sophoroipid is effective in modifying wettability, enhancing displacement efficiency, and facilitating emulsion formation, thereby enhancing sweeping efficiency. In the optimized coreflooding simulations, the recovery factor (RF) increased to a range of 19%-33%.

Keywords: sophorolipids, coreflooding simulation, optimization, sensitivity analysis, sobol analysis.

How to cite this article:

Indah Widiyaningsih, Harry Budiharjo Sulistyarso, Ivan Kurnia, Taufan Marhaendrajana, and Tutuka Ariadji, 2025, Investigation and Optimization of Enhanced Oil Recovery Mechanism By Sophorolipid Biosurfactant in Carbonate Reservoir, Scientific Contributions Oil and Gas, 48 (3) pp. 23-36. DOI org/10.29017/scog.v48i3.1830.

INTRODUCTION

Carbonate reservoirs are an intriguing subject due to their high heterogeneity (Sheng 2013). In general, carbonate rocks have a mix-wet or oil-wet wettability, which causes the residual oil from this type of reservoir to remain relatively high (Ghojavand et al., 2012). Consequently, carbonate reservoirs are considered as good candidates for enhanced oil recovery EOR applications (Dong et al., 2019).

Biosurfactants are biomolecular surface-active agents produced by microorganisms (bacteria, fungi, or yeasts). Compared to chemical surfactants, biosurfactants offer several advantages including low toxicity, biodegradability, affordability, and environmental friendliness (Desai & Banat 1997). Sophorolipid is a type of biosurfactant belonging to the glycolipid group that can increase oil recovery through several mechanisms (Shekhar et al., 2015). First, sophorolipid reduces the interfacial tension (IFT) between oil and water, thereby reducing the cAmerican petroleum institute llary forces that hold the oil in place and making it easier for the oil to be released from the rock pores (Negin et al., 2017). Second, sophorolipid alters the wettability of carbonate rock from its initial oil-wet condition to a more water-wet state(Fardami et al., 2022). This change in wettability reduces oil adhesion to the rock surface, making it easier to displace residual oil with injected water. Third, sophorolipid helps form a stable oil-water emulsions (Ahuekwe et al., 2016).

This emulsification breaks down large oil droplets into smaller ones, allowing them to flow more easily with the injected fluid. Additionally, biosurfactants can interact with heavy oil components, such as resins and asphaltenes, reducing their viscosity or adhesion to the rock (Liu et al. 2019; Suhendar et al. 2020).

In summary, the combination of reduced IFT, wettability alteration, emulsification, and reduced viscosity/adhesion explains the additional oil recovery achieved through the injection of sophorolipid solutions (Marhaendrajana et al. 2025; Pal et al., 2023).

Laboratory-scale coreflooding studies also confirm the efficacy of sophorolipids. Elshafie et al. (2015) reported that the injection of sophorolipid (as a cell-free culture fluid) into Berea core rock successfully recovered an additional 27.27% of residual oil (Sor) remaining after waterflooding. Optimizing sophorolipid injection through coreflooding simulation modeling requires consideration of appropriate input parameters and data processing based on laboratory test results (Hakiki et al., 2015). Important aspects to consider when modeling biosurfactant injection in carbonate rocks include relative permeability modeling, cAmerican petroleum institute llary pressure modeling, surfactant injection modeling, wettability alteration, interfacial tension (IFT) modeling, and rock adsorption modeling (Adila et al., 2022). Sensitivity analysis is commonly performed using the Sobol Analysis (Sobol′ 2001), a statistical method used to identify parameters having a significant influence on the simulation results. Sobol analysis provides that the parameters exhibit varying levels of sensitivity to the model final results, as indicated by the percentage contribution of each parameter (Carrero et al., 2007; Mohsenatabar Firozjaii et al., 2019). Optimisation of biosurfactant injection through reservoir simulation modelling must yield representative results (Pamungkas et al., 2021).

In this study, the investigation and optimization of biosurfactant injection were conducted using laboratory testing on carbonate rock samples. A core flooding test was conducted to obtain maximum recovery using biosurfactants. In the final stage, validation of the carbonate rock simulation model from the coreflooding test was performed. The sensitivity of input parameters in the coreflooding simulation helps identify the dominant parameters of sophorolipids. Biosurfactant injection optimisation was conducted on the concentration, injection pore volume (PV), and injection rate of sophorolipids.

METHODOLOGY

The focus of this research is the investigation and optimization of coreflooding simulations based on the results of laboratory coreflooding tests. In the coreflooding test, the previously designed injection fluid was injected through a rock core sample (Indiana Limestone Core) to evaluate its effectiveness in enhancing oil recovery. The data obtained from this experiment will serve as the basis for subsequent numerical simulations. The use of simulators for optimisation and sensitivity analysis saves time and costs compared to conducting experiments for all optimisation scenarios.

In the coreflooding simulation, the CMG simulator (STARS and CMOST) is used to validate the coreflooding experiment results with simulation parameter matching. When the simulation results do not align with the experimental data, the simulation parameters are adjusted until a match is achieved. After matching is completed, the process continues with operational parameter optimisation, including surfactant concentration, PV injection, and injection rate. The objective of this stage is to determine the most technically and economically practical operational conditions to maximise oil recovery.

Once optimization was completed and optimal operational parameters were obtained, the process was concluded, and recommendations for biosurfactant application in EOR operations were established for potential field implementation.

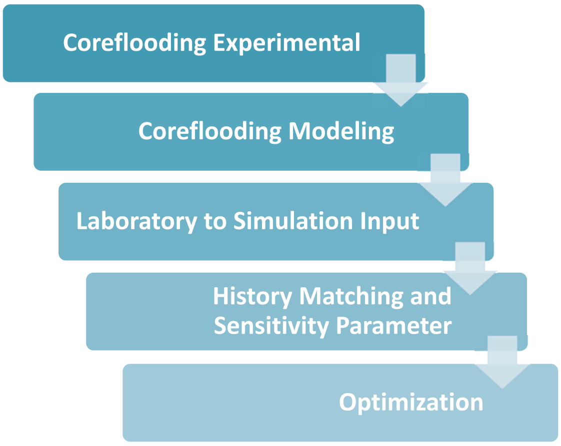


Figure 1. Flowchart

Coreflooding experiment

Coreflooding is a laboratory test in which a fluid or combination of fluids is injected into a rock sample. The objectives include measuring permeability, saturation, and formation damage caused by fluid injection or the interaction between the fluid and the rock (Dianita et al., 2025). Core samples are typically derived from oil reservoirs; however, some tests utilize outcrop rocks. The fluid placed at the start of the test is usually formation brine, which is simulated in this study using synthetic brine, oil (either crude oil or refined oil), or a combination of brine and oil. Coreflooding is typically used to determine optimal development options for oil reservoirs and often helps evaluate the effects of fluid injection designed to enhance or improve oil recovery (Tobing 2018). The core flooding testing equipment is located at the ITB EOR Laboratory and conforms to ASTM D4520 standards (Figure 2). Core flooding testing was conducted by injecting a brine and biosurfactant solution into Indiana Limestone rock samples that were saturated with oil. This test aimed to evaluate the performance of EOR methods, particularly biosurfactant solution injection. The effectiveness of the injected fluid in displacing oil was measured by the oil recovery factor obtained. The scenario in this test involves a continuous process, where brine is injected at 3 pore volumes (PV), followed by biosurfactant injection for an additional 3 PV, with an injection rate of 0.3 cc/min. The coreflooding scenario was conducted at a salinity of 10,000 ppm, considering the field conditions of the oil sample taken, which had a salinity of 8,000–12,500 ppm, with the CMC concentration used.

Coreflooding simulation

The relative permeability parameters were determined using interpolation sets before and after the injection of sophorolipid. When defining the post-injection interpolation set, the sensitivity of the Trapping Number representing the IFT parameter was considered. This reservoir simulation model is based on laboratory tests, considering aspects of relative permeability modeling, sophorolipid injection modeling, wettability alteration, IFT modeling, and rock adsorption modeling.

The Trapping Number Coefficient is a dimensionless number that describes the ratio between the viscous force of the injected fluid and the cAmerican petroleum institute llary force in the pores of the reservoir rock. This number is widely used in Enhanced Oil Recovery (EOR) analysis to evaluate the ability of the injected fluid to release oil trapped in the pores of the rock. Mathematically, the Trapping Number (Ntr) is expressed by the formula

$$Ntr = \frac{\mu v}{\sigma \cos \theta} \qquad (1)$$

(Lake et al., 2014):

Where:

Ntr = Trapping number (dimesionless)

μ = Viscosity of injection fluid (Pa·s)

v = Fluid Injection Velocity (m/s)

σ = interfacial tension (N/m)

θ = Contact Angle (degrees)

The trapping number is closely related to residual oil saturation. A high Ntr value indicates that the injection force is strong enough to overcome cAmerican petroleum institute llary forces, allowing trapped oil to be extracted more easily, resulting in lower residual saturation (Green & Willhite, 1998). Conversely, a low trapping number value indicates

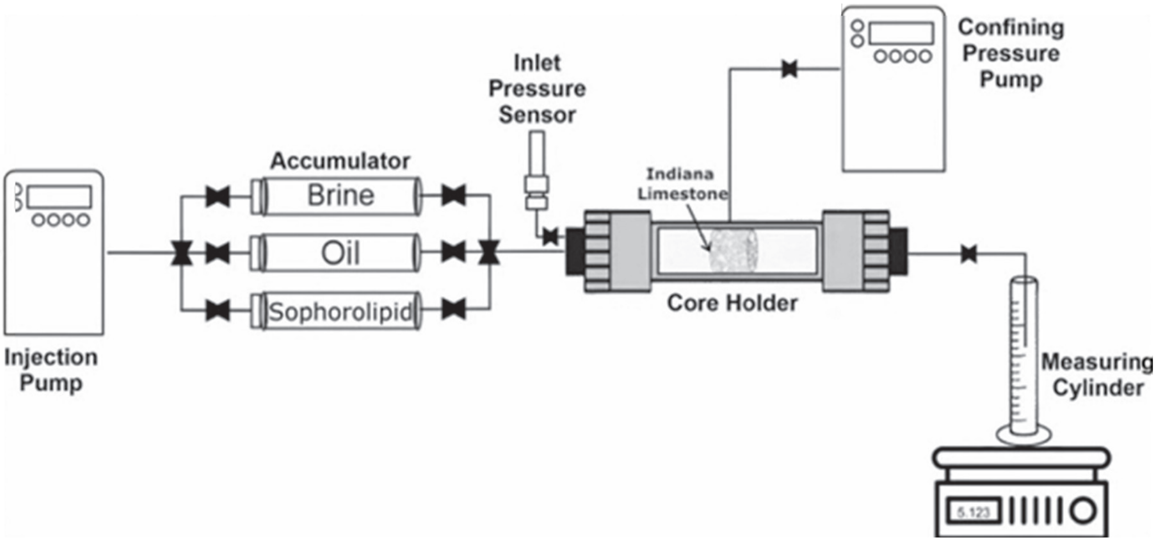


Figure 2. Coreflooding Apparatus

the dominance of cAmerican petroleum institute llary forces, causing oil to remain trapped within the pores of the rock.

RESULT AND DISCUSSION

Coreflooding modeling

This coreflooding simulation utilizes a Cartesian Linear model with a block shape measuring 10 x 1 x 1, comprising a total of 10 grids (Figure 3). The initial

Table 1. Coreflooding parameter input

Core	:	Indiana Limestone	
Diameter	:	2.50	cm
Length	:	5	cm
Volume	:	24.54	cc
Pore Volume (PV)	:	2.28	cc
Porosity	:	9.29	%
Permeability	:	135	m D
Oil Saturation	:	1.9	cc

oil saturation is 1.9 cc, and the total pore volume (PV) is 2.28 cc. The porosity parameter is 9.29% and the permeability is 135 mD based on laboratory measurements (Table 1).

Laboratory data to simulation input

The laboratory experiments conducted form the basis for the input parameters in the coreflooding simulation. Parameters such as IFT, emulsion viscosity, and adsorption require data processing before analysis. The data processing involves converting the units first before they are used as input parameters. The contact angle parameter is the basis for determining the final trapping number, which in turn determines the permeability curve in interpolation set 2, describing the behavior of biosurfactant injection. This input and history matching process is carried out to obtain a representative coreflooding model that is consistent with the laboratory test results.

Interfacial Tension (IFT)

IFT testing was conducted at a brine salinity of 10,000 ppm and various concentrations of sophorolipid. Typical biosurfactant testing shows that as the concentration increases, IFT decreases, but not significantly. Based on IFT testing, the optimal

Table 2. IFT Data

Composotion of component/phase	IFT (dyne/cm)
1e-07	2.13
0.00012389	2.19
0.00024900	5.39
0.00037535	5.92
0.00050296	8.53

 | DOI org/10.29017/scog.v48i3.1830

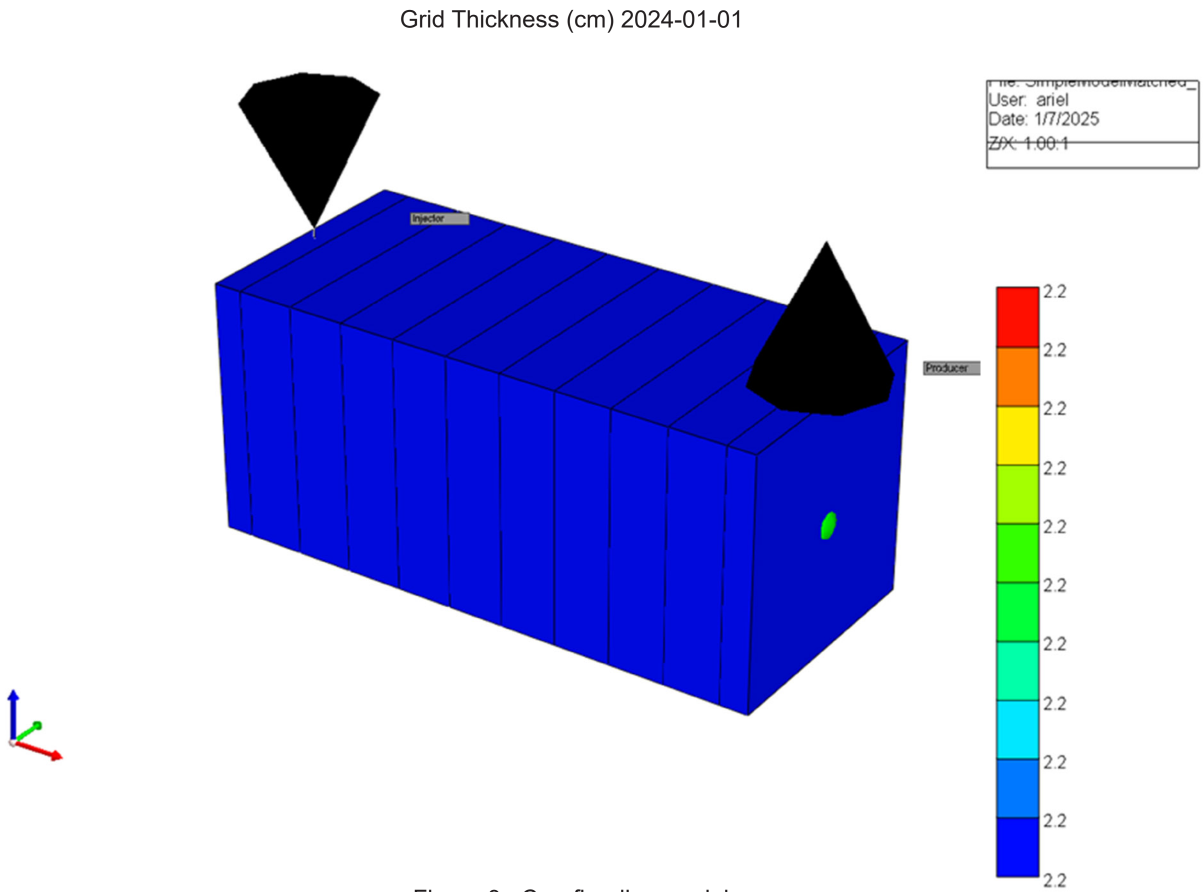


Figure 3. Coreflooding model

sophorolipid concentration for reducing oil-water interfacial tension is 0.5% w/v, where a significant decrease in the curve is observed (Figure 4). The IFT vs. concentration curve serves as input data for the simulator, consistent with laboratory conditions (Table 2).

Emulsion viscosity

The biosurfactant solution was tested at sophorolipid concentrations of 0.5–2.5% w/v and brine salinity of 10,000 ppm. At the same time, the oil sample had a characteristic of 43.45º American petroleum institute with a viscosity of 0.9 cP at a temperature of 60°C. Emulsion viscosity was measured using a 1:1 ratio of biosurfactant solution to oil (16 ml). At the CMC concentration, the emulsion viscosity increased nearly twofold compared to the initial viscosity of the biosurfactant solution or the

Table 3. Emulsion viscosity table

Sophorolipid Concentration (% w/v)	Emulsion Viscosity (cP)
0.5	2.13
1	2.19
1.5	5.39
2	5.92
2.5	8.53

initial oil viscosity (Figure 5). As the sophorolipid concentration increased, the mixture viscosity continued to rise, demonstrating that sophorolipid can emulsify crude oil. This laboratory data serves as input for the oil viscosity table, which defines the emulsion viscosity (Table 3).

Wettability alteration

Testing of wettability alteration in Indiana Limestone cores due to the injection of sophorolipid was conducted using the contact angle method. Changes in contact angle before and after sophorolipid treatment demonstrated the effectiveness of biosurfactants in wettability alteration (Figure 6). Contact angle measurements were taken at various sophorolipid concentrations at a brine salinity of

10,000 ppm at a temperature of 60°C.

Adsorption

The following laboratory test result was the static adsorption of biosurfactants on carbonate rock. This study utilized Indiana limestone carbonate rock samples and sophorolipid solution at concentrations of 0.5% w/v and 2% w/v, which served as the input parameters for the coreflooding simulation (Figure 7).

Table 4. Adsorption input

Mole Fraction	Adsorbed Moles per Unit Pore Volume (gmole/cm3)
0	0
0.000123	0.0000026323

For simulation input data, unit conversion is required to align with laboratory test results (Table 4).

Sensitivity and history matching

Currently, history matching with sensitivity analysis were conducted with optimization software (CMOST-CMG). Coreflooding simulations were performed using all input parameters, after which values are chosen for sensitivity analysis in history matching. The subsequent table displays the sensitivity parameters (Table 5).

The sensitivity analysis results obtained through Sobol analysis are shown in Figure 8. Based on this analysis, the parameter that significantly influences the history matching process is the non-wetting trapping number (DTRAPN), accounting for 73% of the influence. DTRAPN plays a crucial role in determining the extent of oil trapped within rock pores after fluid injection processes such as biosurfactant flooding. Under conditions with high DTRAPN, the injection process improves oil recovery efficiency because trapped oil can be released more easily. CAmerican petroleum institute llary trapping occurs when cAmerican petroleum institute llary forces hold oil in the pores of reservoir rock, preventing oil from moving efficiently during flooding. The interaction between the injected fluid (such as water or biosurfactant solution) and the oil trapped in the rock pores is very significant in determining the efficiency of oil recovery. To improve the efficiency of the flooding process, special attention must be paid to control the interfacial tension that affects the cAmerican petroleum institute llary effect. IFT, rock wettability properties, and emulsion viscosity greatly influence DTRAPN. In this case, wettability alteration and emulsion viscosity are the dominant mechanisms in the coreflooding injection scenario using sophorolipid, since the IFT do not reach ultralow values.

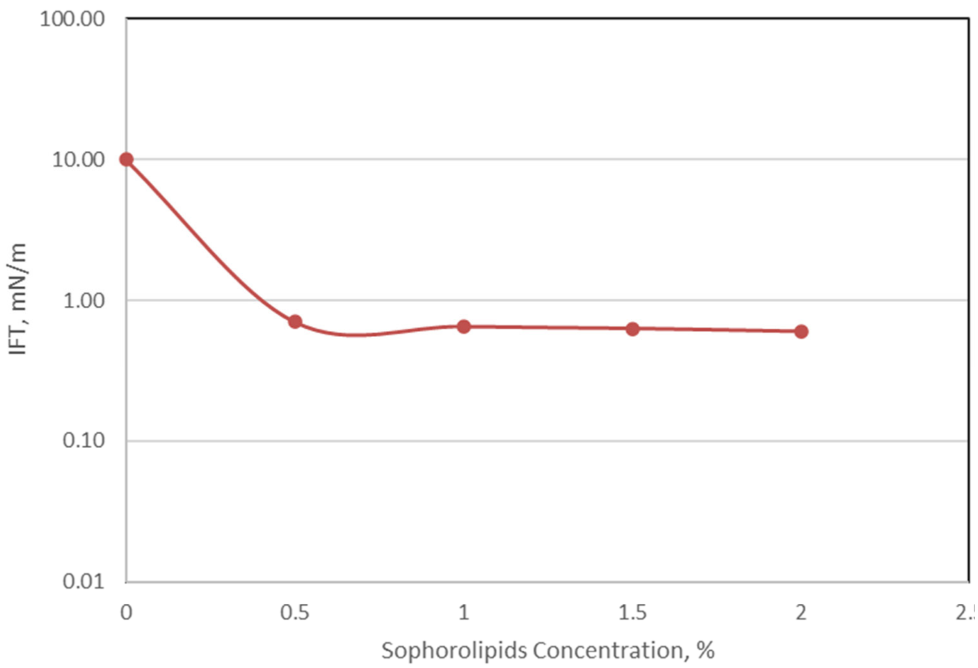


Figure 4. IFT vs sophorolipids concentration

Table 5. Sensitivity parameter

No.	Parameter	Min	Max	Unit
1	Admaxt	2	20	mg/gram rock
2	Dtrapn	-4	-1	dimensionless
3	Dtrapw	-4	-1	dimensionless
4	Injection Rate	0.03	0.57	cm3/min
5	Kro@Swi_lnp2	0.4	1	dimensionless
6	Krw@Sor_lnp2	0.15	0.9	dimensionless
7	Sor_lnp2	0.1	0.35	dimensionless
8	Now_lnp2	1	5	dimensionless
9	Nw_lnp2	1	3	dimensionless
10	Oil Viscosity	0.5	5	cP
11	Biosurfactant Viscosity	0.3	5	cP
12	Water Viscosity	0.3	2	cP
13	Permeability	50	250	mD
14	MW_Oil	0.2	0.6	kg/gmole
15	Temperature	25	95	°C

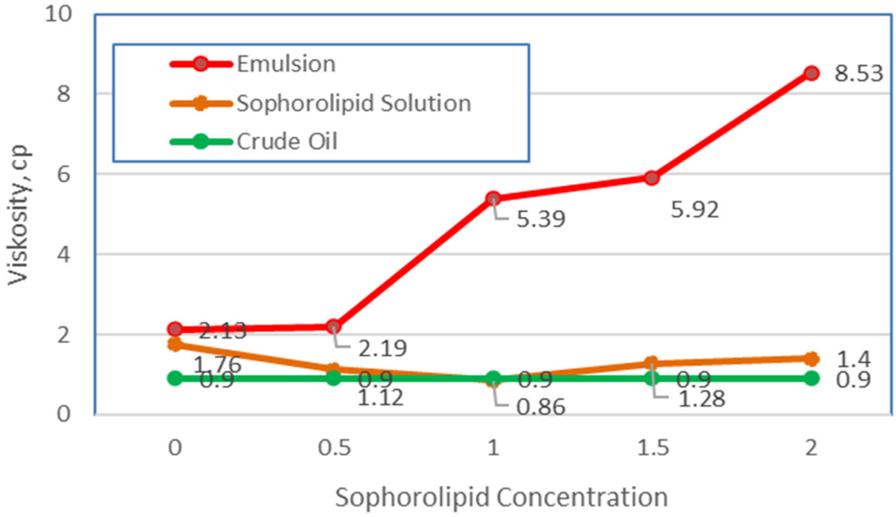


Figure 5. Viscosity vs sophorolipid concentration

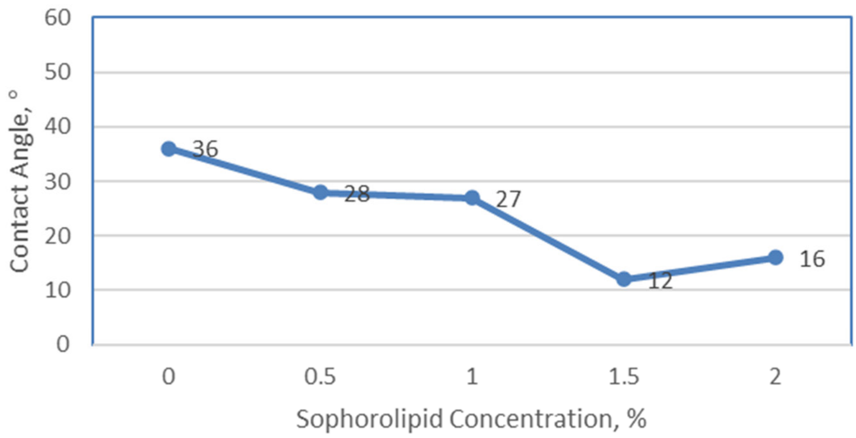


Figure 6. Contact Angle vs sophorolipid concentration

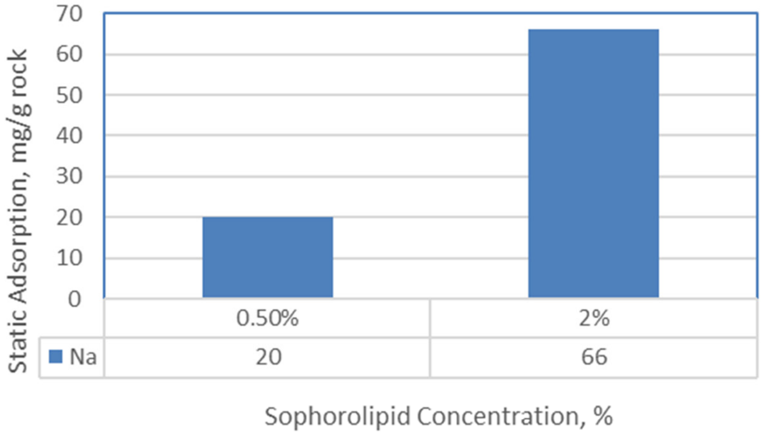


Figure 7. Static Adsorption vs sophorolipid concentration

The second most influential parameter with the highest sensitivity is water viscosity (22%). Water viscosity has a significant impact on fluid flow in water injection and surfactant processes, particularly in determining sweep efficiency during the flooding process. Variations in water viscosity directly affect the fluid distribution and efficiency of the oil recovery process.

Oil viscosity also has a fairly noticeable sensitivity, albeit small (1.9%).

Oil viscosity affects the mobility of oil in reservoirs and also determines the displacement efficiency (the effectiveness of oil displacement by injection fluid).

Other parameters such as KrwatSor2, Permeability_K, Nw2, and so on, show relatively small sensitivity (around 1% or less). These parameters have a minimal impact on the simulation results, so that uncertainty in these parameters does not significantly affect the final results.

The results of this analysis indicate that modelling and optimisation in studies or projects should focus primarily on the Dtrapn2 and water

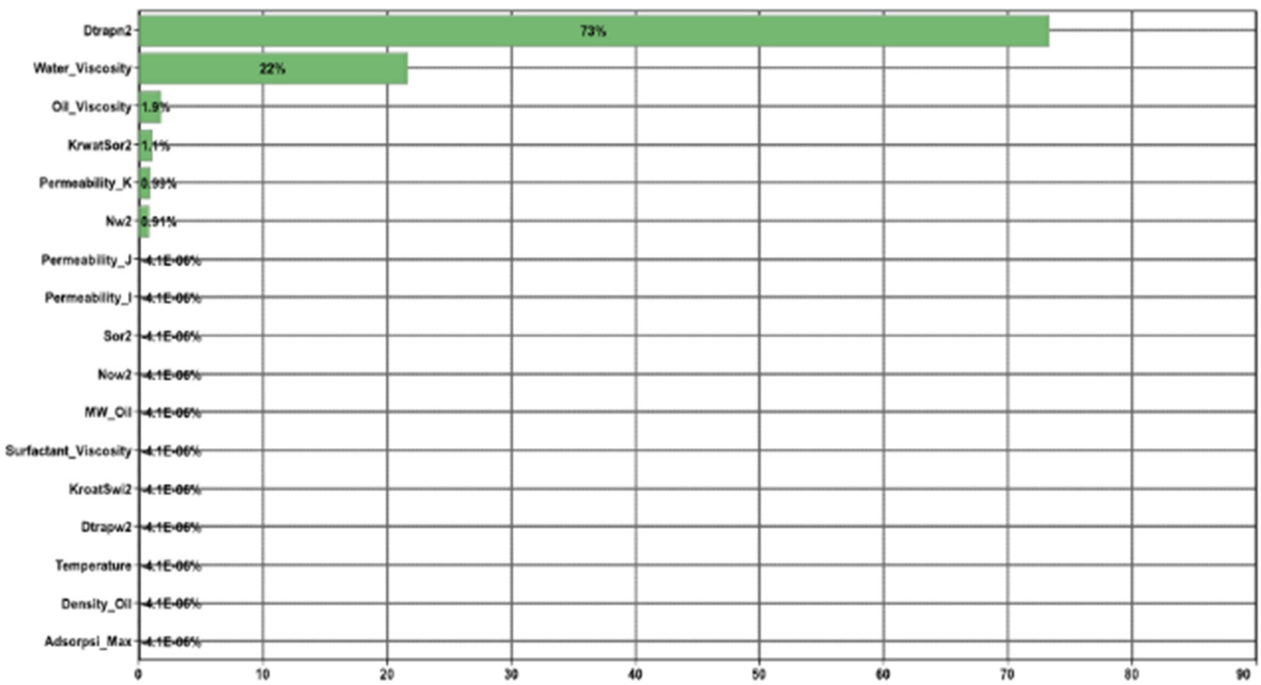


Figure 8. Sobol analysis

| DOI org/10.29017/scog.v48i3.1830

viscosity parameters, as small changes in these parameters will cause significant changes in the simulation results. This is crucial to consider when designing effective and efficient flood scenarios. This analysis produces a matching curve between the laboratory scenario and the simulation model. The results of the history matching graph are shown in Figure 9. The next step is to use the history matching model to optimise the coreflooding scenario.

In coreflooding modeling, determining the behavior of biosurfactant injection is crucial. The relative permeability curve (Figure 10) shows the performance of water injection and surfactant injection.

This curve is defined from the initial water injection process, which indicates the initial residual oil position (interpolation set 1), and the second curve, which represents the results after sophorolipid injection, showing the final residual oil after EOR (interpolation set 2).

The relative permeability curve, used as input data, is shown in Figures 11a and 11b. The trapping numbers for water (DTRAPW) before -5 and after -2, and for oil (DTRAPN) before -5 and after -3.5, are the results of history matching.

Optimization scenario

Sophorolipid concentration optimization

The analysis of sophorolipid concentration versus cumulative oil shows a significant increase in cumulative oil from around 1.10 cc to 1.13 cc. This indicates that the addition of sophorolipid at low concentrations has a substantial effect on wettability alteration and reduces interfacial tension (IFT), thereby increasing oil sweeping.

The increase in cumulative oil tends to level off, indicating that the effectiveness of biosurfactants in reducing IFT and enhancing oil mobilization which is approaching its optimal limit in this range. Further increases in concentration result in progressively diminished increments in oil, with the graph approaching a nearly flat line. This is likely due to the saturation effect, where excess biosurfactants do not provide a significant improvement in recovery efficiency (Figure 11).

At initial concentrations, the reduction in IFT is very noticeable enhancing the sweeping ability of biosurfactants. This zone represents a crucial initial turning point in enhancing oil recovery in low-concentration zones, where concentrations are below 0.5%.

At the optimal concentration range (0.5%–1%), the reduction in IFT and the interaction of biosurfactants with pore surfaces provide maximum effect without oversaturation. In practice, this is

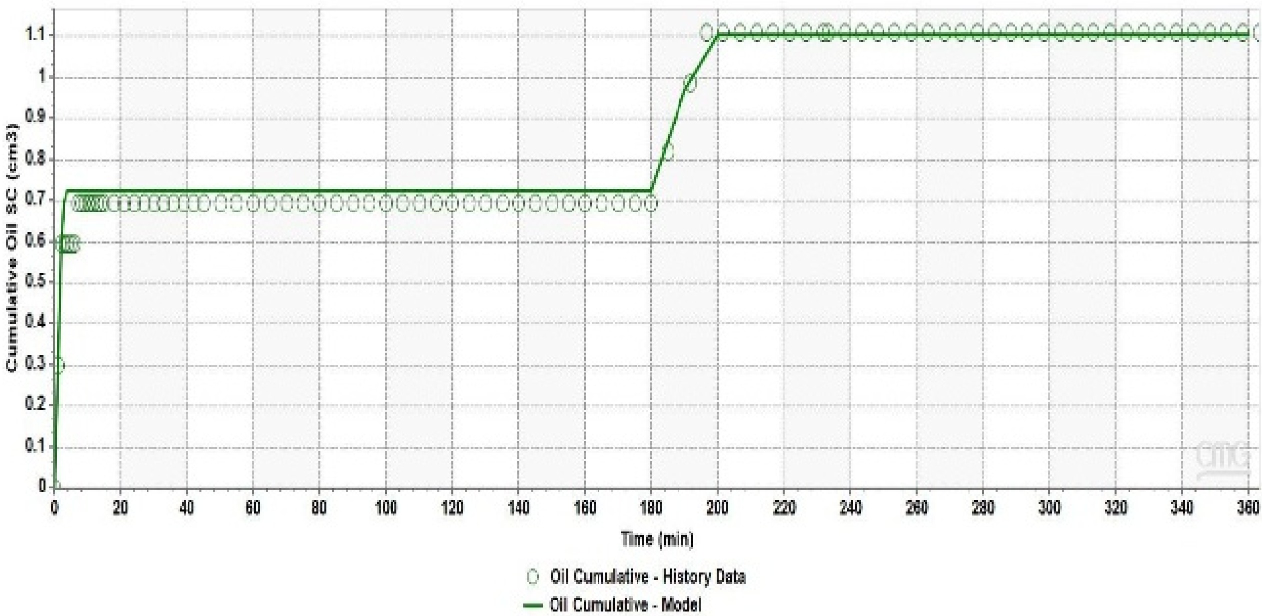
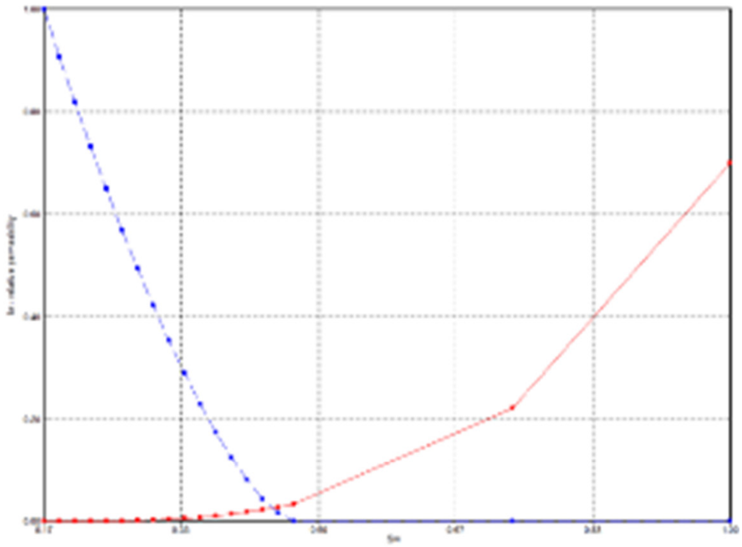
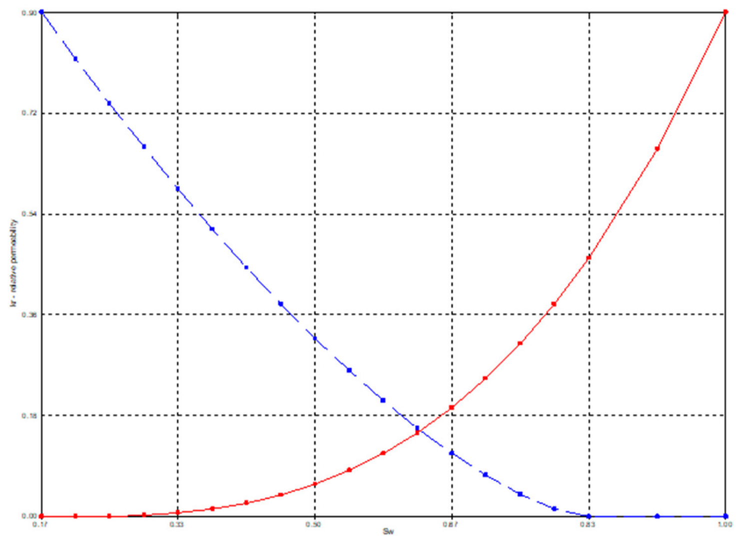


Figure 9. History matching coreflooding



(a)



(b)

Figure 10. Interpolation set: (a) waterflooding; (b) sophorolipid flooding

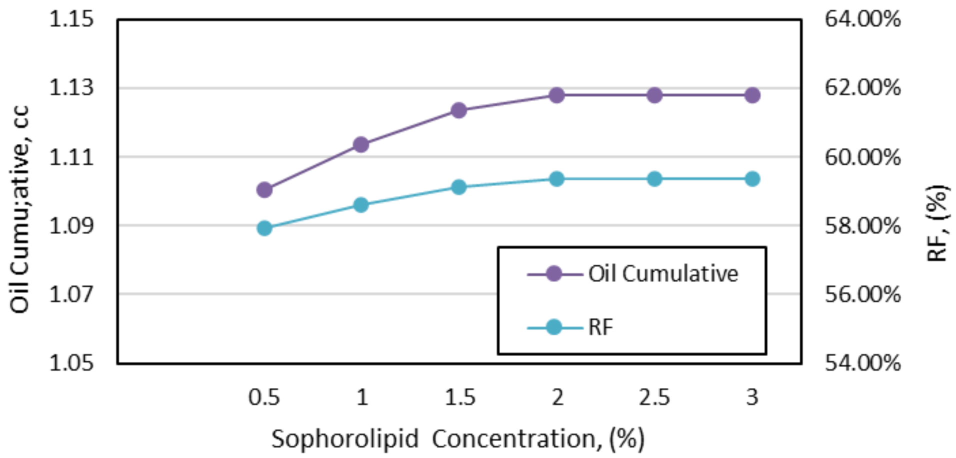


Figure 11. Sophorolipid concentration vs oil cumulative/rf

the ideal concentration target for injection. At concentrations above 1%, excess biosurfactant begins to be absorbed onto the reservoir rock surface or becomes trapped within the formation, reducing its efficiency. Additionally, the extra cost associated with higher concentrations may not justify the increased cumulative oil recovery. This analysis graph shows that the optimal sophorolipid concentration ranges from 0.5% to 1%, where cumulative oil recovery is most efficient. Increasing the concentration above 1% yields diminishing returns, indicating the technical and economic limits of biosurfactant use.

Pore volume injection optimization

The following PV (Pore Volume) Injection versus cumulative oil graph shows a significant increase in cumulative oil from around 1.078 cc to 1.095 cc. This indicates that in the early stages, biosurfactant injection is highly effective in enhancing oil mobilization. The increase in recovery begins to level off at injection volumes above 1 PV. This indicates that most of the readily producible oil has been successfully removed, and the effect of the biosurfactant is beginning to reach its efficiency limit.

At high injection pressure, the cumulative oil increase becomes smaller, resulting in an almost flat graph (Figure 12). This indicates diminishing returns, where additional injections yield minimal results because most of the target zone has already been saturated. At low injection volumes, biosurfactants work optimally to reduce interfacial tension (IFT) and increase the swept area. At this stage, most of the oil trapped in zones with high saturation is successfully produced. When the injection reaches around 1–2 PV, most of the oil in the target zone has been successfully produced.

The injected biosurfactants begin to spread to zones with low oil saturation, reducing their efficiency. Injection volumes greater than 2 PV do not yield significant results. At this stage, the majority of easily mobilizable oil has been extracted, and the remaining biosurfactant only spreads without providing substantial improvement. The optimal injection volume is in the range of 1 to 2 PV, where oil recovery improvement is most efficient. Additional injection above 2 PV is not economical, as it yields only a small extra amount of oil.

Injection rate optimization

The injection rate versus cumulative production graph shows a significant increase in cumulative oil from around 1.1 cc to 1.2 cc. A low injection rate supports efficient biosurfactant distribution, maximizing the sweeping area. At low injection rates, the increase in cumulative oil begins to level off. This suggests that a higher injection rate yields increased recovery, but it is less effective than a low rate in mobilizing oil in hard-to-reach areas. At high injection rates, the graph flattens out, indicating that increasing the injection rate above 1.5 cc/min does not significantly impact additional oil production. It is possible that fingering (also known as fluid fingers) begins to occur, causing bypass of the remaining oil.

At low rates, the biosurfactant has more contact time with the oil trapped in the rock pores, thereby increasing oil mobilisation. The cAmerican petroleum institute llary effect is more dominant, helping to distribute the biosurfactant evenly throughout the reservoir.The injection rate is considered optimal because it produces a wider sweeping area with faster processing time compared to a low rate. The increase in recovery begins to level off because the central production

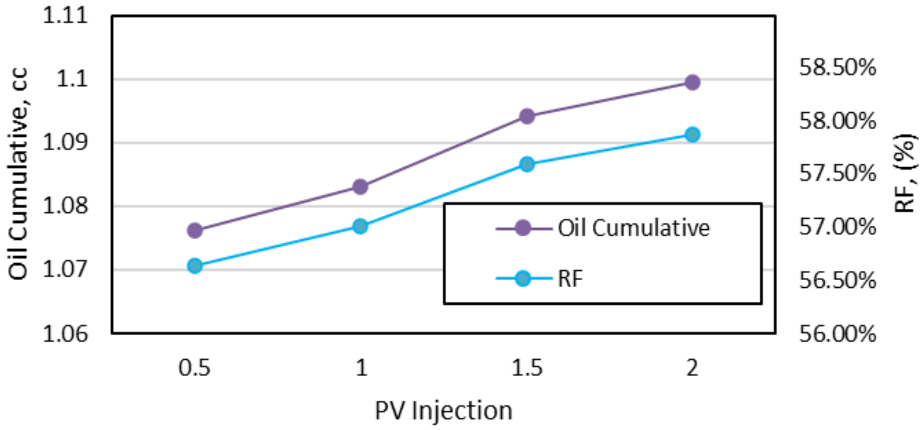


Figure 12. PV injection vs oil cumulative/RF

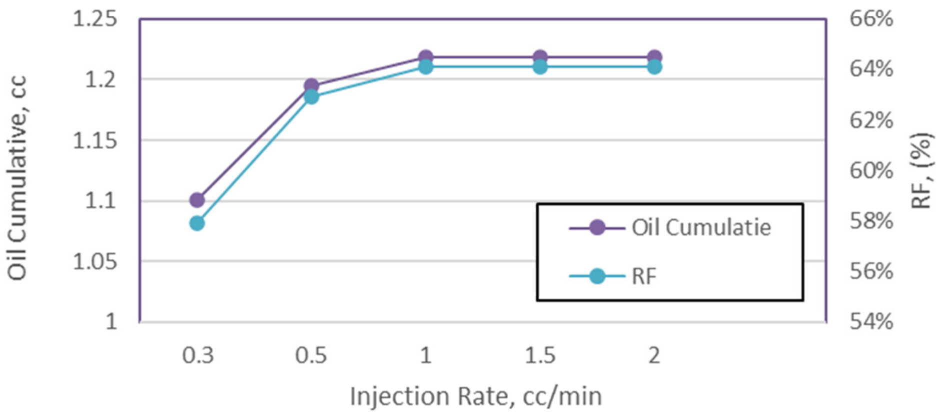


Figure 13. Injection rate vs oil cumulative/RF

zone has been effectively swept. At high rates, the biosurfactant passes through the oil zone quickly, causing a bypass effect. This phenomenon reduces sweeping efficiency in certain zones. This effect also suggests that high speeds lead to uneven distribution, particularly in areas with higher oil viscosity. Figure 13 shows that the optimal injection rate lies within the range of 0.5 to 1 cc/min, where the cumulative oil increase is significant without a bypass effect. Injection rates above one cc/min yield minimal and inefficient results, both technically and economically. It is recommended to use a moderate injection rate to maximise recovery without increasing the risk of fingering or biosurfactant waste.

CONCLUSION

The Sobol sensitivity analysis indicates that the most dominant parameter is the non-wetting trapping number (DTRAPN), which is closely related to the cAmerican petroleum institute llarity mechanisms. Since the IFT does not reach ultra-low values, the crucial parameters on DTRAPN are wettability alteration and emulsion viscosity caused by the injection of Sophorolipid. This enhances the Sophorolipid mechanism for altering wettability, augmenting displacement efficiency, and promoting emulsion formation, thus, it raises sweeping efficiency. The optimal conditions for injecting sophorolipid into carbonate rock are a Sophorolipid concentration of 0.5% to 1%, an RF of 58% to 59%, a PV injection of 2 PV with an RF of 57.9%, and an injection rate of 0.5 cc/min with an RF of 63%.

GLOSSARY OF TERMS

Symbol	Definition	Unit
EOR	Enhanced Oil Recovery	
M	Mobility ratio	
Ev	Volumetric sweep efficiency	
EA	Areal sweep efficiency	
Ei	Vertical sweep efficiency	
SCAL	Special Core Analysis	
Ø	Porosity	%
k	Permeability	mD
IOIP	Initial oil in place	%
PV	Pore volume	
ROIP	Residual oil in place	%
RF	Recovery Factor	%
DTRAPN	Trapping Number (Non-wetting/Oil)	

ACKNOWLEDGEMENT

This study was funded by the Higher Education Fund, Ministry of Education, Culture, Research, and Technology of the Republic of Indonesia, through Grant No: 0742/J5.2.3/BPI.06/10/2021. The experiments were conducted in the Laboratory of Enhanced Oil Recovery (EOR) at Institut Teknologi Bandung and UPN Veteran Yogyakarta.

REFERENCES

Adila, A., Al-Shalabi, E. W., & AlAmeri, W. (2022). Geochemical Modeling of Hybrid Surfactant and Engineered Water Injections in Carbonate Reservoirs under Harsh Conditions. SPE Journal, 27(1), 728–752. https://doi.org/10.2118/204351-

PA.

Ahuekwe, E. F., Okoli, B. E., Stanley, H. O. & Kinigoma, B. (2016). Evaluation of Hydrocarbon Emulsification and Heavy Metal Detoxification Potentials of Sophorolipid Biosurfactants Produced From Waste Substrates Using Yeast and Mushroom .

Carrero, E., Queipo, N. V, Pintos, S., & Zerpa, L. E. (2007). Global sensitivity analysis of Alkali–Surfactant–Polymer enhanced oil recovery processes. Journal of Petroleum Science and Engineering, 58(1), 30–42. https://doi.org/https://doi.org/10.1016/j.petrol.2006.11.007.

Desai, J. D., & Banat, I. M. (1997). Microbial production of surfactants and their commercial potential. Microbiology and Molecular Biology Reviews, 61(1), 47–64. https://doi.org/10.1128/mmbr.61.1.47-64.1997.

Dianita, C., Faturahman, M., & Mardianza, A. (2025). Pore-Scale 3D Modeling of Viscous Fingering for Non-Newtonian Heavy Oil Recovery. Scientific Contributions Oil and Gas, 48(1), 77-90. https://doi.org/10.29017/scog.v48i1.1690.

Dong, P., Puerto, M. C., Ma, K., Mateen, K., Ren, G., Bourdarot, G., Morel, D., Biswal, S. L., & Hirasaki, G. J. (2019). Ultralow-interfacial-tension foam-injection strategy in high-temperature ultrahigh-salinity fractured oil-wet carbonate reservoirs. SPE Journal, 24(6), 2822–2840. https://doi.org/10.2118/190259-PA.

Elshafie, A. E., Joshi, S. J., Al-Wahaibi, Y. M., Al-Bemani, A. S., Al-Bahry, S. N., Al-Maqbali, D., & Banat, I. M. (2015). Sophorolipids production by Candida bombicola ATCC 22214 and its potential application in microbial enhanced oil recovery. Frontiers in Microbiology, 6(NOV), 1–11. https://doi.org/10.3389/fmicb.2015.01324.

Fardami, A. Y., Kawo, A. H., Yahaya, S., Lawal, I., Abubakar, A. S., & Maiyadi, K. A. (2022). A Review on Biosurfactant Properties, Production and Producing Microorganisms. Journal of Biochemistry, Microbiology and Biotechnology, 10(1), 5–12. https://doi.org/10.54987/jobimb.v10i1.656.

Ghojavand, H., Vahabzadeh, F., & Shahraki, A. K. (2012). Enhanced oil recovery from low permeability dolomite cores using biosurfactant produced by a Bacillus mojavensis (PTCC 1696) isolated from Masjed-I Soleyman field. Journal of Petroleum Science and Engineering, 81, 24–30. https://doi.org/10.1016/j.petrol.2011.12.002.

Green, D. W., & Willhite, G. P. (1998). Enhanced Oil Recovery. Henry L. Doherty Memorial Fund of AIME, Society of Petroleum Engineers. https://books.google.co.id/books?id=0cUWAAAACAAJ.

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(6), 706–725. https://doi.org/10.5614/j.eng.technol.sci.2015.47.6.9.

Lake, L. W., Johns, R. T., Rossen, W. R., & Pope, G. A. (2014). Fundamentals of Enhanced Oil Recovery. Society of Petroleum Engineers.

Liu, X., Yao, T., Lai, R., Xiu, J., Huang, L., Sun, S., Luo, Y., Song, Z., & Zhang, Z. (2019). Recovery of crude oil from oily sludge in an oilfield by sophorolipid. Petroleum Science and Technology, 37(13), 1582–1588. https://doi.org/10.1080/10916466.2019.1594286.

Marhaendrajana, T., Widiyaningsih, I., Kurnia, I., & Sulistyarso, H. B. (2025). Fluid-to-Fluid and Fluid-to-Rock Interaction on Sophorolipids Biosurfactant for Enhanced Oil Recovery: A Literature Review. Scientific Contributions Oil and Gas, 48(1), 63-76. https://doi.org/10.29017/SCOG.48.1April.1688.

Mohsenatabar Firozjaii, A., Akbari, M., & Zargar, G. (2019). Sensitivity analysis and optimization on effective parameters during chemical enhanced oil recovery (CEOR) using experimental design and numerical simulation. Energy Sources, Part A: Recovery, Utilization and Environmental Effects, 41(15), 1847–1861. https://doi.org/10.1080/15567036.2018.1549164.

Negin, C., Ali, S., & Xie, Q. (2017). Most common surfactants employed in chemical enhanced oil recovery. Petroleum, 3(2), 197–211. https://doi.org/10.1016/J.PETLM.2016.11.007.

Pal, S., Chatterjee, N., Das, A. K., Julian, D., & Dhar, P. (2023). Sophorolipids : A comprehensive review on properties and applications. Advances in Colloid and Interface Science, 313(January), 102856. https://doi.org/10.1016/j.cis.2023.102856.

Pamungkas, J., Sulistyarso, H. B., Widiyaningsih, I., & Hanqenina Damayanti. (2021). Core Flooding Experiment to Increase Recovery Factor Using “U- Champ” Biosurfactant. SCIREA, 01, 1–7.

Shekhar, S., Sundaramanickam, A., & Balasubramanian, T. (2015). Biosurfactant producing microbes and their potential applications: A review. Critical Reviews in Environmental Science and Technology, 45(14), 1522–1554. https://doi.org/10.1080/10643389.2014.955631.

Sheng, J. J. (2013). Review of Surfactant Enhanced Oil Recovery in Carbonate Reservoirs. Advances in Petroleum Exploration and Development, 6(June), 1–10. https://doi.org/10.3968/j.aped.1925543820130601.1582.

Sobol′, I. M. (2001). Global sensitivity indices for nonlinear mathematical models and their Monte Carlo estimates. Mathematics and Computers in Simulation, 55(1), 271–280. https://doi.org/https://doi.org/10.1016/S0378-4754(00)00270-6.

Suhendar, A., Hertadi, R., & Alli, Y. F. (2018). MOLECULAR DYNAMICS STUDY OF OLEIC ACID-BASED SURFACTANTS FOR ENHANCED OIL RECOVERY. Scientific Contributions Oil and Gas, 41(3), 125-135. https://doi.org/10.29017/scog.41.3.331.

Tobing, E. M. L. (2018). Test Sensitivity Surfactant-Polimer Concentration and Volume of Slug on Oil Recovery Through Simulation Model Production Injection Well Pattern EOR. Lembaran Publikasi Minyak Dan Gas Bumi, 52(1), 1-13. http://www.journal.lemigas.esdm.go.id.