JOURNAL OF PETROLEUM AND GEOTHERMAL TECHNOLOGY
ISSN: 2723-0988, e-ISSN: 2723-1496
Vol. 6 No. 2 2025

Chemical Enhanced Oil Recovery (CEOR) Injection Planning to Obtain the Optimum Development Scenario: A Case Study in TBG Field

Tubagus Adam Aliefan [1*], Dedi Kristanto [1], Boni Swadesi [1]
[1] Petroleum Engineering, Universitas Pembangunan Nasional Veteran Yogyakarta
* corresponding email: adam.alifan@pertamina.com

ABSTRACT

Chemical Enhanced Oil Recovery (CEOR), particularly through the use of surfactant and polymer injection, has emerged as one of the most effective tertiary recovery techniques for increasing oil recovery from mature reservoirs. CEOR enhances volumetric and microscopic sweeping efficiency, improving the overall recovery factor (RF). This study focuses on Zone C of the TBG Field, a mature oil field with a current recovery factor below 25%, highlighting its potential for further optimization through CEOR. The field, which began production in 1961 and introduced peripheral water injection in 1995, remains a key candidate for unlocking remaining oil in place. This research integrates primary data, including core analysis, PVT data, and polymer field trial results, with secondary data such as petrophysical properties and production performance. Using dynamic modeling with CMG software, the study evaluates three CEOR injection scenarios to determine the most effective method for improving oil recovery. The scenarios simulated included Baseline Waterflood + Polymer (0.4 PV) and Baseline Waterflood + (Surfactant + Polymer) + (Polymer) (0.2 PV SP + 0.7 PV P). The optimal scenario, involving Baseline Waterflood + (Surfactant + Polymer) + (Polymer), demonstrated an incremental oil recovery of 1.24 MMSTB and a recovery factor improvement of 0.974%. The novelty of this research lies in its integration of polymer field trial data with innovative surfactant-polymer combinations tailored specifically to Zone C's reservoir characteristics. This approach provides a scientifically robust and practical strategy for enhancing oil recovery in challenging reservoir conditions. The study concludes that CEOR is a viable method for mature fields like TBG, offering significant potential for improved oil recovery. Future recommendations include exploring the economic feasibility of the selected injection scenario and ensuring the readiness of surface facilities to support full-scale implementation.

Keywords: Chemical EOR injection; Development scenario; Injection optimization

I. INTRODUCTION

The increasing demand for oil and gas has pushed the boundaries of technology and methods in the energy sector, especially in enhancing recovery from mature fields. Indonesia, characterized by its aging oil fields discovered as early as 1905, faces challenges in maximizing recovery from these assets. Mature fields, often defined by high water cut levels exceeding 90% and a recovery factor above 30%, have undergone extensive primary and secondary recovery stages. In such fields, tertiary recovery methods, such as Chemical Enhanced Oil Recovery (CEOR), present a viable solution to extract remaining hydrocarbons efficiently.

The TBG Field, located in South Kalimantan, is a mature oil field operated by PT Pertamina EP under a Production Sharing Contract until 2035. Since its discovery in 1898, the field has undergone several recovery phases, including a successful implementation of waterflooding in 1995. Despite these efforts, the potential for incremental oil recovery remains significant, particularly in Zone C, where polymer field trials have demonstrated promising results. This research aims to investigate and plan an optimal CEOR injection strategy tailored for Zone C of the TBG Field to improve oil recovery factors while addressing challenges associated with chemical injection in heterogeneous reservoirs.

This study leverages advanced reservoir simulation techniques, laboratory analysis of chemical performance, and a detailed evaluation of geological and petrophysical properties of the target zone. By integrating these approaches, this research seeks to identify the most effective CEOR methods and injection scenarios, contributing to sustainable energy production and improved resource management in Indonesia's oil and gas sector.

II. LITERATURE REVIEW

2.1. Hydraulic Flow Unit Analysis

The Hydraulic Flow Unit (HFU) is an approach used to classify reservoirs based on geological and petrophysical properties that control fluid flow. Amaefule et al. (1993) defined HFU as a reservoir volume characterized by uniform pore geometry that influences the rock's permeability and porosity. HFU grouping utilizes flow attributes such as the mean hydraulic radius, which correlates with porosity, permeability, and capillary pressure. In CEOR, HFU analysis is essential for identifying high-potential zones within the reservoir and designing effective chemical injection strategies.

2.2. Injection Fluid Selection Analysis

The selection of injection fluid for CEOR depends on reservoir conditions such as oil viscosity, salinity, and reservoir temperature. According to Cheraghian and Hendraningrat (2016), the commonly used fluids include:

- Surfactants: These reduce the interfacial tension (IFT) between oil and water, making trapped oil easier to mobilize. Anionic surfactants are often preferred due to their chemical stability under moderate salinity and temperature conditions.
- Polymers: These increase the viscosity of the injection fluid, enhance volumetric sweep efficiency, and prevent fingering phenomena (Abidin et al., 2012).
- Surfactant-Polymer (SP) Combination: This combines the functionalities of surfactants and polymers to improve both microscopic and volumetric sweep efficiency. Bera et al. (2020) reported that SP injection could reduce IFT to as low as 10^{-3} dyne/cm and increase the recovery factor by up to 25%.

The effectiveness of injection fluids heavily depends on their chemical formulation and the operational parameters of the reservoir. Laboratory testing is crucial to determine the optimal concentrations that yield maximum results.

2.3. Ranking Pattern Analysis for CEOR Injection Targets

The identification of CEOR injection targets involves a ranking pattern method based on specific criteria, such as oil saturation, remaining oil in place (ROIP), transmissibility, and well integrity. Liang et al. (2018) suggested using weighted criteria to prioritize the most suitable patterns. ROIP is often assigned the highest weight as it is the primary parameter determining the potential of remaining oil in the reservoir.

According to Ekrem Alagoz (2023), each pattern is evaluated by assigning scores ranging from 1 to 5 for each criterion, where higher scores indicate better quality. The ranking pattern method allows for selecting injection zones with the highest production potential while minimizing technical and economic risks in CEOR implementation.

2.4. Chemical EOR Injection Simulation

Reservoir simulation is a vital tool for planning optimal CEOR development scenarios. Using software like CMG (Computer Modeling Group), various parameters can be analyzed, including:

- Injection Rate: Determines the required volume of injection fluid.
- Chemical Concentration: Optimizes microscopic and volumetric sweep efficiency.
- Salinity and Fluid Viscosity: Assesses the chemical stability under reservoir conditions.

Simulations enable testing of different injection scenarios, provide production forecasts, and help optimize operational costs. Ramos et al. (2020) emphasized the importance of validating simulation models through history matching before field implementation to ensure accurate results.

III. METHODOLOGY

The research methodology for planning Chemical Enhanced Oil Recovery (CEOR) injection in Zone C of the TBG Field as shows in Figure 1 consists of several stages. First, a preliminary study was conducted to gather and review literature related to CEOR techniques and their applications in mature fields. This was followed by collecting primary data, including core analysis, PVT data, and polymer trial results, alongside secondary data such as petrophysical properties, reservoir production history, and geological characteristics.

The next stage involved data processing and analysis. Hydraulic Flow Unit (HFU) analysis was carried out to classify the reservoir based on geological and petrophysical properties, identifying high-potential zones. Injection fluid selection was performed using screening criteria to evaluate the suitability of surfactant and polymer formulations under reservoir conditions, such as salinity, temperature, and viscosity. Additionally, ranking pattern analysis was conducted to prioritize target zones for CEOR injection based on criteria such as oil saturation, remaining oil in place (ROIP), transmissibility, and well integrity.

Dynamic reservoir simulation was then performed using CMG software. This included data input, history matching to validate the reservoir model, and designing CEOR injection scenarios. Sensitivity analysis was conducted to assess the performance of various scenarios, focusing on incremental oil recovery and recovery factor improvement.

The final step involved evaluating the CEOR injection scenarios to identify the optimal method based on technical feasibility, production forecasts, and recovery factor improvements. The selected scenario was further analyzed to ensure operational readiness and compatibility with the reservoir's characteristics.

JOURNAL OF PETROLEUM AND GEOTHERMAL TECHNOLOGY
ISSN: 2723-0988, e-ISSN: 2723-1496
Vol. 6 No. 2 2025

The methodology concludes with formulating recommendations for CEOR implementation in Zone C and identifying areas for further research, such as economic feasibility and surface facility optimization. This structured approach ensures a comprehensive evaluation of CEOR's potential to enhance oil recovery in the TBG Field.

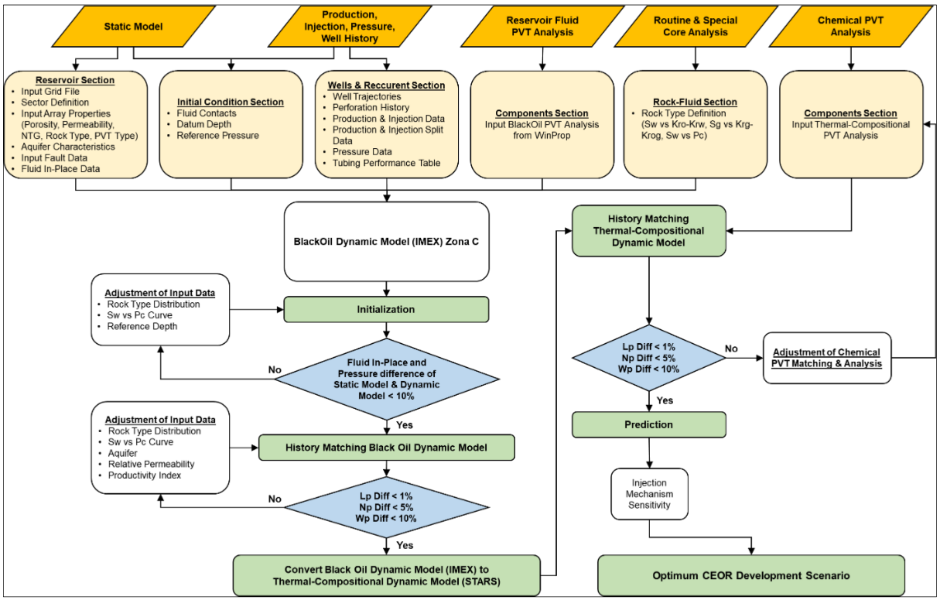


Figure 1. Flowchart Methodology of the Research

IV. RESULTS AND DISCUSSION

4.1. Data Availability

The data used in this study includes primary and secondary data. Primary data consists of routine core analysis, Special Core Analysis (SCAL), PVT data, and polymer field trial results, while secondary data includes well logs, production history, and geological data. These datasets form the foundation for hydraulic flow unit analysis, fluid injection selection, and reservoir simulation modeling. Figure 2 shows sufficient data distribution in Zone C, ensuring reliable characterization for CEOR planning and Table 1 and Table 2 shows Routine Core Analysis and Special Core Analysis

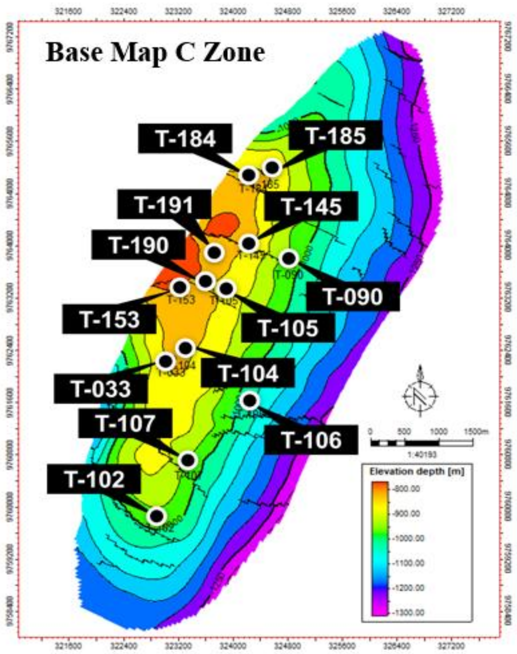


Figure 2. Map of Routine Core Data Distribution of Zone C

Table 1. Routine Core Data Availability

No	Well	Report Date	Analyst	Zone				Routine Core Analysis				
				A	B	C	D	Porosity	Horizontal Permeability	Vertical Permeability	Grain Density	Lithology
1	T-033	12-Jun-61	Koninklijke/Shell-Lab	9	6	2	1	18	18	-	√	-
2	T-090	31-Jan-78	LEMIGAS	3	-	1	1	5	5	-	-	-
3	T-102	8-May-91	PT. Corelab Indonesia	21	-	8	-	29	29	9	√	-
4	T-104	24-Nov-93	PT. Corelab Indonesia	83	69	68	3	223	223	69	√	√
5	T-105	24-Nov-93	LEMIGAS	132	77	28	33	270	270	85	√	√
6	T-106	14-Apr-94	PT. Corelab Indonesia	55	14	44	-	113	113	34	√	-
7	T-107	11-Jul-94	LEMIGAS	108	53	-	-	161	161	-	-	-
8	T-145	10-Dec-07	BJ Services	21	-	16	-	37	37	-	√	√
	T-145	31-Dec-07	LEMIGAS									
9	T-153	14-Jan-09	LEMIGAS	15	6	13	9	43	43	-	√	√
10	T-184	2019	PT. Geoservices	69	8	28	14	119	119	24	√	√
11	T-185	2021	PT. Geoservices	61	18	39	24	142	142	29	√	√
12	T-190	2022	PT. Geoservices	64	38	10	17	129	129	34	√	√
13	T-191	2022	PT. Geoservices	61	47	19	11	138	138	36	√	√
TOTAL				702	336	276	113	1427	1427	320		

Table 2. Special Core Data Availability

No	Well	Report Date	Analyst	Zone				Special Core Analysis								
				A	B	C	D	Kro-Krw	Kro-Krg	Pc-Sw	Formation Compressibility	Wettability	FF	a, m, n	Rw	Bio-stratigraphy
1	T-090	31-Jan-78	LEMIGAS	√		√	√	2	5	5			√	√	√	
2	T-102	5-Dec-91	PT. Corelab Indonesia	√		√		3		2						
3	T-104	8-Dec-94	PT. Corelab Indonesia	√	√	√	√	4	6	4			√	√	√	
4	T-105	18-Jul-94	LEMIGAS	√	√	√	√	4	4	10	4	6	√	√	√	
5	T-107	11-Jul-94	LEMIGAS	√	√			2	2	2			√	√		
6	T-145	31-Dec-07	LEMIGAS	√		√		6			8	8	√	√	√	
7	T-153	14-Jan-09	LEMIGAS	√	√	√	√	16		16	16	15	√	√	√	
8	T-184	2019	PT. Geoservices	√	√	√	√	25	27	28	28	28	√	√	√	√
9	T-185	2021	PT. Geoservices	√	√	√	√	32	32	33	33	26	√	√	√	√
10	T-190	2022	PT. Geoservices	√	√	√	√	22	22	30	22		√	√	√	√
11	T-191	2022	PT. Geoservices	√	√	√	√	21	22	43			√	√	√	√
TOTAL								137	120	173	111	83				

4.2. Identification of Injection Water Displacement Phase Based on Fractional Flow

Fractional flow analysis was performed to evaluate the efficiency of water displacement in Zone C. Relative permeability curves (Kro-Krw) and capillary pressure data were analyzed to understand oil mobility and the effects of water injection. CEOR was found to improve displacement efficiency by modifying the fractional flow curve and reducing residual oil saturation. Figure 3 shows highlights improved fractional flow efficiency due to CEOR, especially for rock types with high residual oil saturation. This supports the feasibility of CEOR in Zone C.

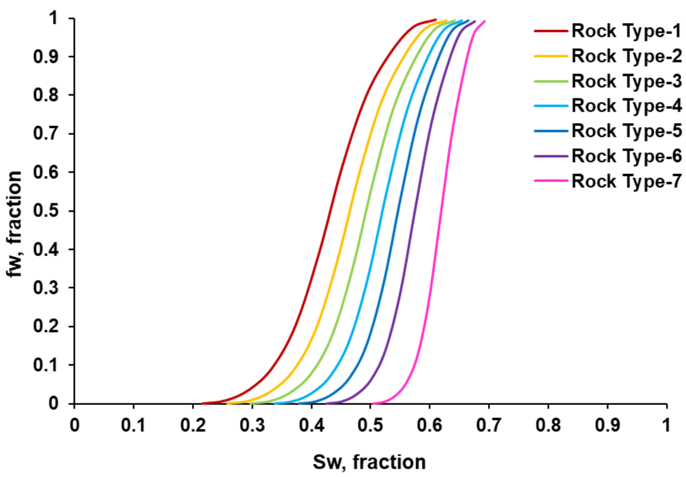


Figure 3. Fractional Flow Curves for Each Rock Type

4.3. PVT Data Analysis

The analysis of PVT data confirmed the suitability of Zone C for CEOR applications. Key fluid properties such as formation volume factor (Bo), oil viscosity (μo), and gas-oil ratio (GOR) were analyzed. The moderate oil viscosity and relatively low GOR make Zone C an ideal candidate for surfactant-polymer injection. Figure 4 and Figure 5 shows Accurate matching between simulated and measured data validates the fluid property inputs for reservoir simulation.

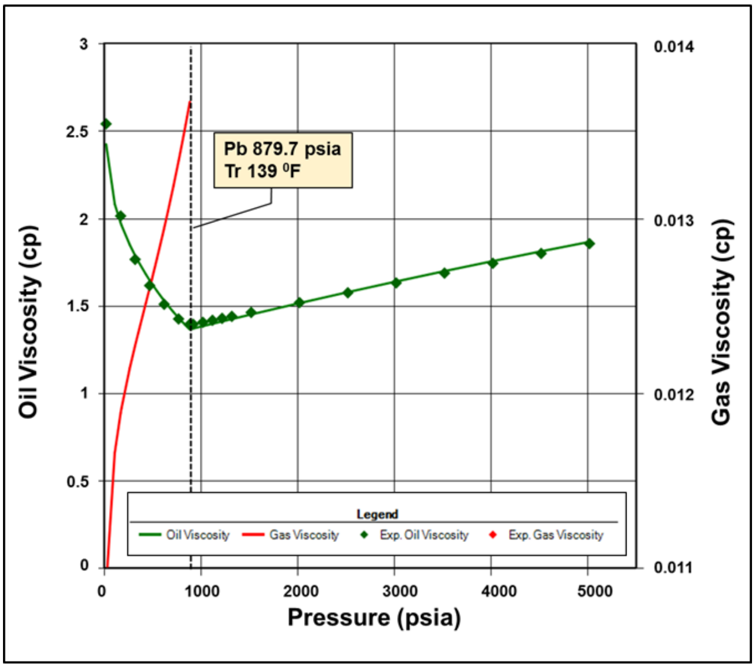


Figure 4. PVT Matching Results of Pressure vs Oil and Gas Viscosity

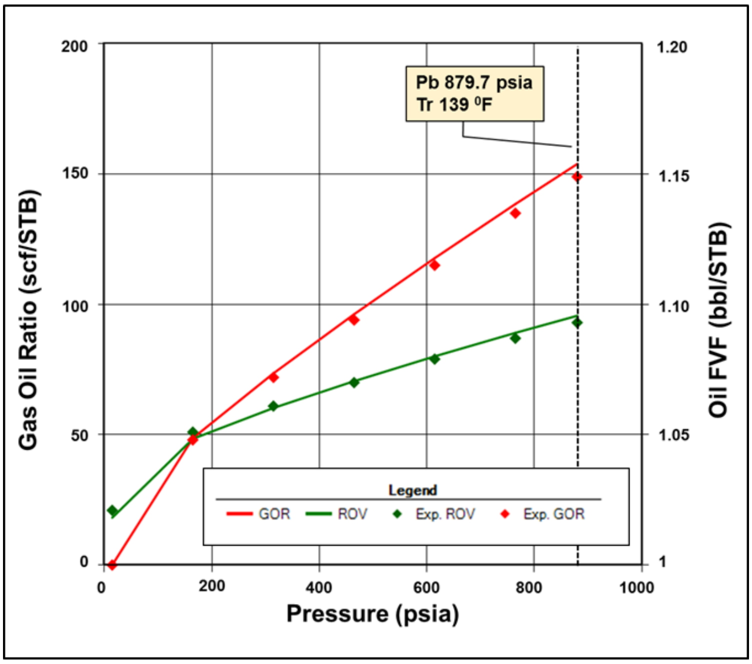


Figure 5. PVT Matching Results of Pressure vs GOR and Bo

4.4. Production Performance in Zone C of the TBG Field

Historical production data from Zone C shows a decline in oil production and an increase in water cut, with water cut exceeding 90%. The cumulative oil production indicates that primary and secondary recovery methods have been largely exhausted, making CEOR a critical step for further recovery. Figure 6 shows the graph highlights the maturity of the reservoir, with production dominated by water. This emphasizes the need for CEOR to mobilize the remaining oil.

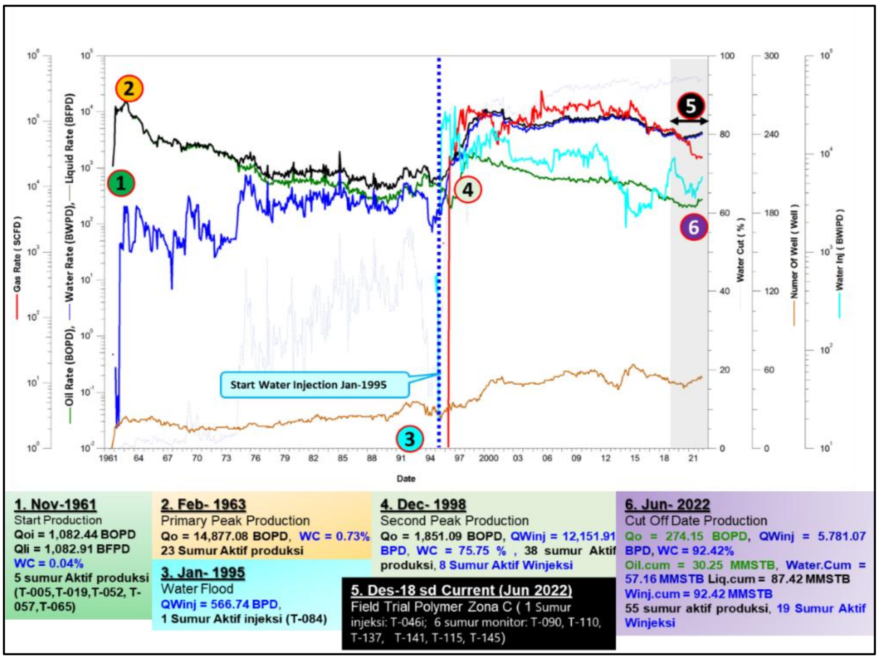
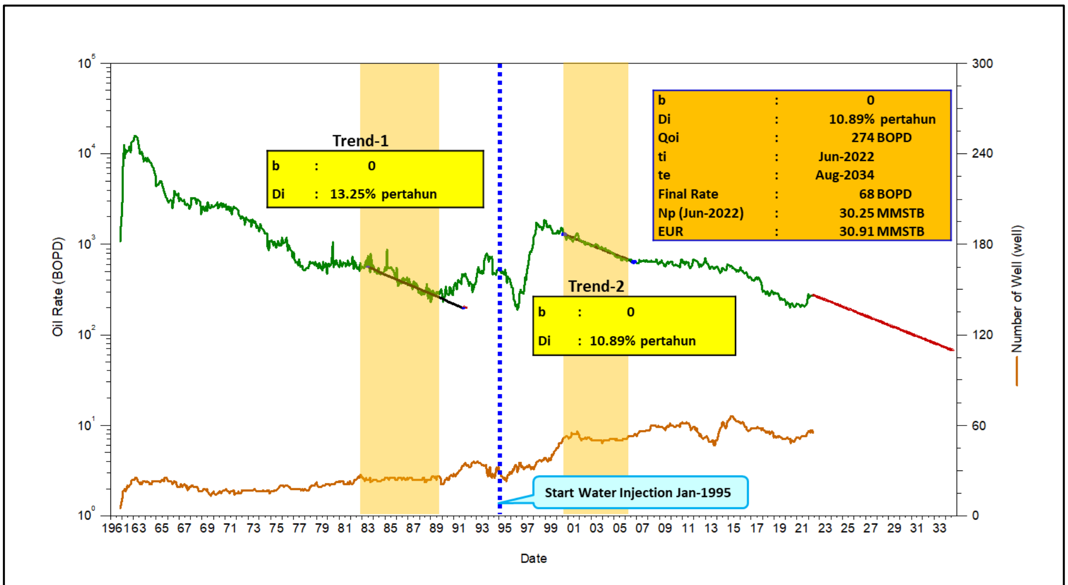


Figure 6. Production Performance Trends of Zone C

4.5. Decline Curve Analysis (DCA) in Zone C

Decline Curve Analysis (DCA) revealed that the recovery factor (RF) for Zone C is currently below 25%. The exponential production decline suggests that additional recovery through conventional methods is unlikely, reinforcing the need for tertiary recovery via CEOR. Figure 7 shows the graph confirms the presence of substantial remaining oil in place, justifying the implementation of CEOR to extend production life.



b	Di /year	Qoi, BOOPD	ti	Te	*OOIP, MMSTB	Np @Jun-2022, MMSTB	Current RF, %	EUR, MMSTB	ERR MMSTB	URF, %
0	10.89%	274	Jun-22	Aug-34	124.31	30.25	24.33	30.91	0.66	24.87

Figure 7. Decline Curve Analysis Result of Zone C

4.6. Simulation Model Preparation

A dynamic reservoir simulation model was developed using CMG software, integrating geological, petrophysical, and production data. History matching was performed to ensure the accuracy of the model in replicating past production trends, making it a reliable tool for evaluating CEOR scenarios. Figure 8 and Figure 9 shows a close match between simulated and historical data validates the model, enabling its use for reliable forecasting and scenario evaluation.

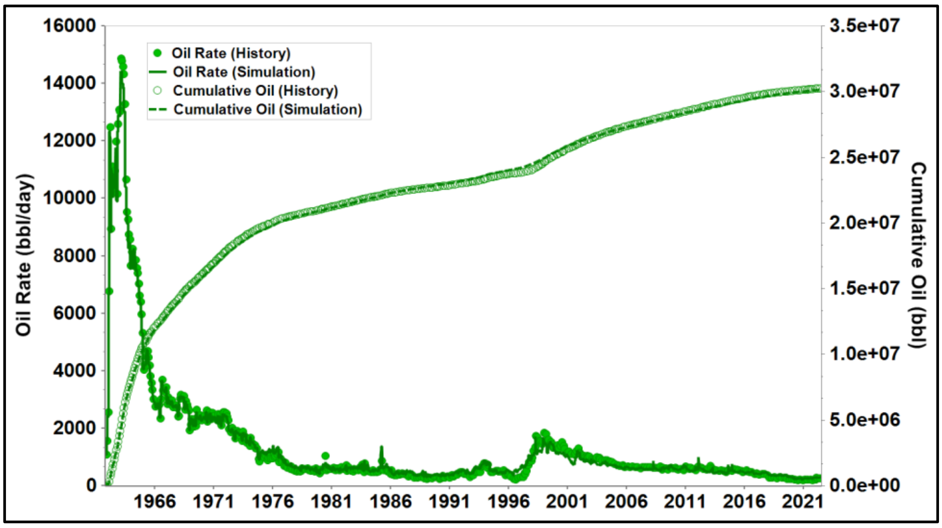


Figure 8. History Match Results of Oil Rate and Cumulative Oil Production in Zone C

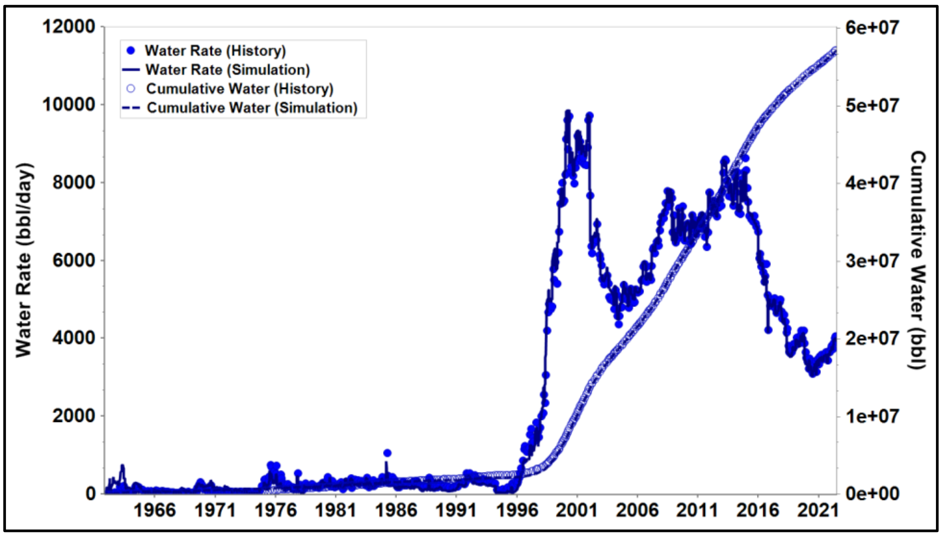


Figure 9. History Match Results of Water Rate and Cumulative Water Production in Zone C

4.7. Surfactant-Polymer Validation

The validation of a reservoir simulation model aims to determine the input parameters for chemical injection (a combination of surfactant and polymer) in tertiary oil recovery methods. This process is carried out using coreflood testing in Zone C, involving a total of 14 samples simulated through the stages of modeling, initialization, and history matching. The tested polymers include FP3230S and FP3630S, while the surfactants tested consist of Alfoterra S23, 4105 ID 0.36% + NaCl 5000 ppm, and ASP5690.

The analysis results indicate that the surfactant-polymer combination provides the best outcome in enhancing oil production. This is evident from the data presented in the table on the right, which compares the Recovery Factor (RF) from laboratory results (IOIP and ROIP) to simulations. The surfactant-polymer combination scenarios for samples 13 and 14 shown in the table exhibit the highest incremental RF compared to pure polymer scenarios, as shown in Table 3. Meanwhile, Figure 10 demonstrates the effectiveness of SP injection in mobilizing trapped oil, further validating its application for Zone C.

4.8. Ranking Pattern Target for CEOR Injection

Ranking analysis prioritized injection patterns based on oil saturation, remaining oil in place (ROIP), transmissibility, and well integrity. Pattern 27 was identified as the optimal target due to its favorable reservoir conditions and well integrity. Figure 11 shows the average permeability and histogram for the target area to confirms the high permeability of Pattern 27, supporting efficient chemical injection and oil displacement, and Table 4 shows the ranking process, ensuring the most suitable pattern is chosen for injection.

JOURNAL OF PETROLEUM AND GEOTHERMAL TECHNOLOGY
ISSN: 2723-0988, e-ISSN: 2723-1496
Vol. 6 No. 2 2025

Table 3. Summary Chemical Coreflood

Scenario	No	Chemical	Slug Size	Incremental RF Lab		Incremental RF Simulasi		Data Availability			
				IOIP	ROIP	IOIP	ROIP	Raw Core Flooding Data	Surfactant Formulation Lab Test	Polymer Formulation Lab Test	Surfactant-Polymer Formulation Lab Test
Polymer Zona C	10	FP3230S 2000 ppm	1.0PV P	17.8	28.31	17.42	27.54	☑	-	☑	-
	11	FP3630S 2000 ppm	0.4PV P	3.37	7.37	2.49	5.32	☑	-	☑	-
(Surfactant-Polymer) + Polymer Zona C	12	(Alfoterra S23 0.225% + FP3230S 500 ppm) + FP3230S 2000 ppm	0.2PV SP + 0.7PV P	15.7	18.01	15.29	17.50	☑	☑	☑	☑
	13	(4105 ID 0.36%+NaCl 5000 ppm+FP3230S 500 ppm) + FP3230S 2000 ppm	0.2PV SP + 0.7PV P	21.83	31	20.28	28.83	☑	☑	☑	☑
	14	(ASP5690 1.25% + FP3230S 500 ppm) + FP3230S 2000 ppm	0.3PV SP + 0.4PV P	17.31	31.31	17.17	24.28	☑	☑	☑	☑

☑	Data is Available/Stage is Done
☑	Data is Digitized from Report
☑	ata is Not Available but could refer to A Zor

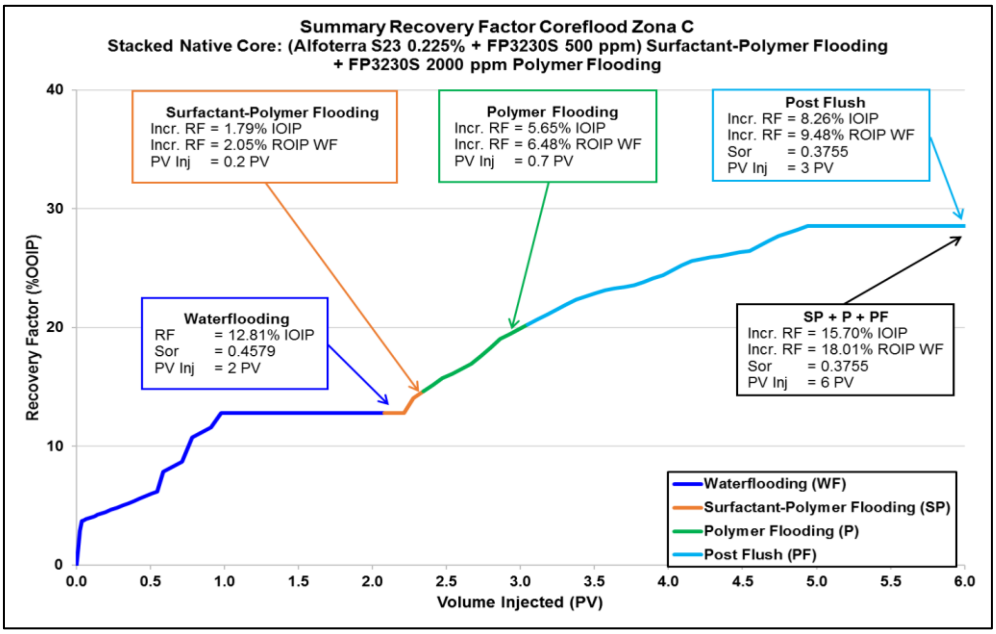


Figure 10. Coreflood Simulation Results Shows Incremental Oil Recovery with SP Injection

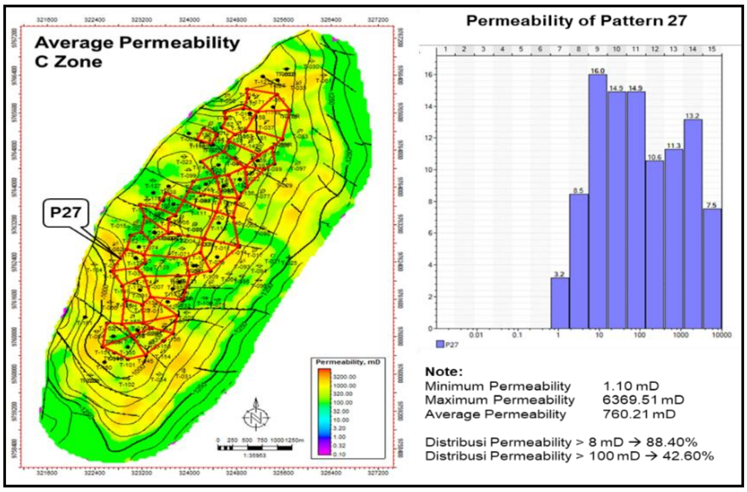


Figure 11. Permeability Distribution in Pattern 27 in Zone C

Table 4. The Scoring and Weighting Process for Selection of Patterns Rank

Polymer			
	Criteria	**Weight**	**Preferable Conditions**
I	**Movable Oil Saturation**	10	The higher the better (1), has the same weight to Permeability
II	**Movable Remaining Oil in Place**	20	The higher the better (1), function of Oil Saturation, Area, Thickness, Porosity. Has 2x weight to Oil Saturation and Permeability (2)
III	**Area Pattern**	10	The smaller the better (3), function of Well Spacing. Well Pattern has small effect to incremental recovery (3)
IV	**Average Transmissibility**	10	The higher the better (1), function of Permeability and Thickness, has the same weight to Oil Saturation
V	**Injector Well Integrity**	30	Good injector well integrity
VI	**Producer Well Integrity**	20	Good producer well integrity
Surfactant/Surfactant-Polymer			
	Criteria	**Weight**	**Preferable Conditions**
I	**Oil Saturation**	10	The higher the better (1), has the same weight to Permeability
II	**Remaining Oil in Place**	20	The higher the better (1), function of Oil Saturation, Area, Thickness, Porosity. Has 2x weight to Oil Saturation and Permeability (2)
III	**Area Pattern**	10	The smaller the better (3), function of Well Spacing. Well Pattern has small effect to incremental recovery (3)
IV	**Average Transmissibility**	10	The higher the better (1), function of Permeability and Thickness, has the same weight to Oil Saturation
V	**Injector Well Integrity**	30	Good injector well integrity
VI	**Producer Well Integrity**	20	Good producer well integrity

4.9. Reservoir Simulation and Production Forecast

Three CEOR injection scenarios were simulated:

1. Baseline Waterflood + Polymer (0.4 PV, FP3230S 2000 ppm)
2. Baseline Waterflood + (Surfactant + Polymer) + Polymer (0.2 PV SP + 0.7 PV P, Alfoterra S23 0.225% + FP3230S 500 ppm)
3. Baseline Waterflood + (Surfactant + Polymer) + Polymer (0.2 PV SP + 0.7 PV P, 4105 ID 0.36% + NaCl 5000 ppm)

Scenario 2 yield the highest incremental oil recovery of 1.24 MMSTB and an RF improvement of 0.974%. This scenario combines high technical feasibility with significant recovery potential. Figure 12 shows the optimization results for injection flow rates.

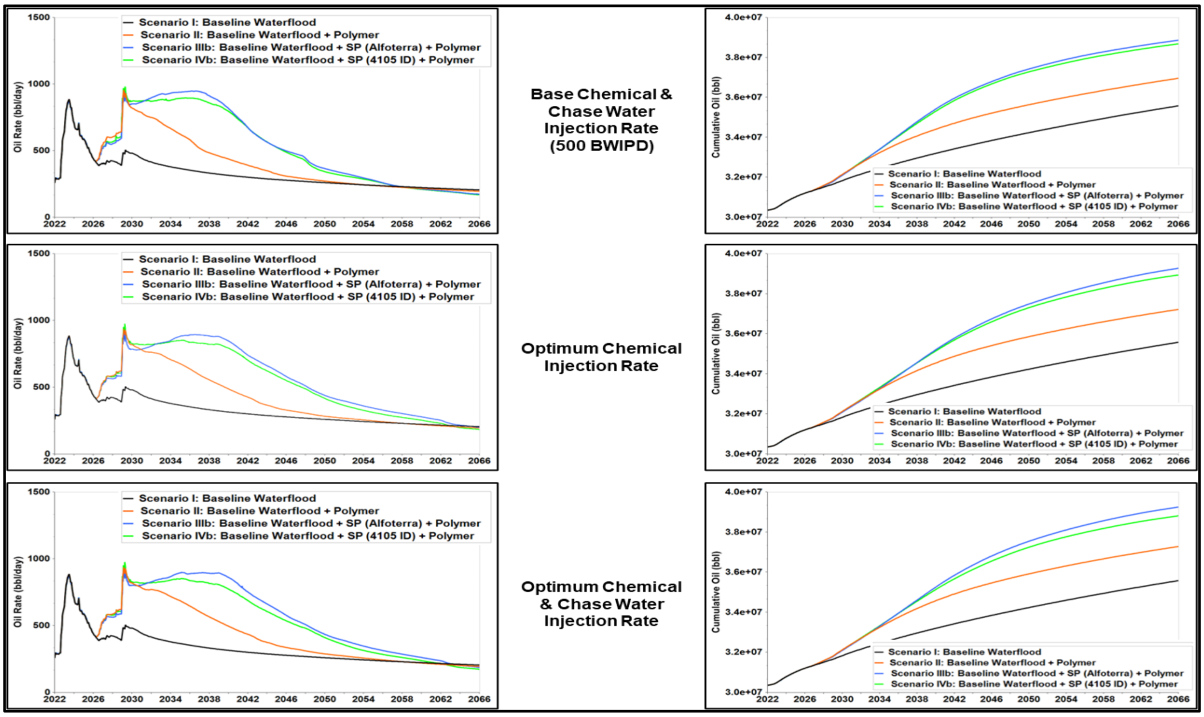


Figure 12. Optimization Results for Injection Flow Rates

V. CONCLUDING REMARKS

Based on the analysis and discussion, several conclusions can be drawn. First, using the Hydraulic Flow Unit (HFU) method, the reservoir rock in Zone C of the TBG Field is classified into seven distinct rock types. Second, the analysis of suitable CEOR injection methods for Zone C identifies three potential scenarios: (a) Baseline Waterflood + Polymer (FP3230S 2000 ppm) with 0.4 PV (P); (b) Baseline Waterflood + (Surfactant + Polymer) + (Polymer) with Alfoterra S23 0.225% + FP3230S 500 ppm for 0.2 PV (SP) followed by FP3230S 2000 ppm for 0.7 PV (P); and (c) Baseline Waterflood + (Surfactant + Polymer) + (Polymer) with 4105 ID 0.36% + NaCl 5000 ppm for 0.2 PV (SP) followed by FP3230S 2000 ppm for 0.7 PV (P). Lastly, the optimal injection scenario for Zone C, based on an incremental oil recovery of 1.24 MMSTB and a recovery factor improvement of 0.974%, is Baseline Waterflood + (Surfactant + Polymer) + (Polymer) using Alfoterra S23 0.225% + FP3230S 500 ppm for 0.2 PV (SP) followed by FP3230S 2000 ppm for 0.7 PV (P).

ACKNOWLEDGEMENTS

The authors would like to thank the Petroleum Engineering Department, Universitas Pembangunan Nasional "Veteran" Yogyakarta for the support in the completion of the research.

REFERENCES

Abdurrahman, M., (2017). Chemical Enhanced Oil Recovery (EOR) Activities in Indonesia: How it’s Future. *AIP Conference Proceedings, 1840*.

Ahmed, Tarek H., (1989). “*Hydrocarbon Phase Behavior*”, Gulf Publishing Company, Houston, Texas, Chapter 8.

Amyx, J.W., Bass, D. W. Jr., Whiting, R.L, “*Petroleum Reservoir Engineering Physical Properties*”, Mc Graw Hill Books Company, New York, Toronto, London, 1660, p. 359 - 381.

Bera, A., Shah, S., Shah, M., Agarwal, J., & Vij, R. K. (2020). Mechanistic Study on Silica Nanoparticles-Assisted Guar Gum Polymer Flooding for Enhanced Oil Recovery in Sandstone Reservoirs. *Colloids and Surfaces A: Physicochemical and Engineering Aspects, 598*, 124833.

Craft, B.C and Hawkins, M.F., (1959). “*Applied Petroleum Reservoir Engineering*”, Prentice-Hall, Inc., Englewood Cliffs, New Jersey, Chapter 10.

Dake, L.P., (1978). “*Fundamentals of Reservoir Engineering*”, Elsevier, New York, Chapter 1.

Danesh, A., (1988). “*PVT and Phase Behavior of Petroleum Reservoir Fluids*”, Elsevier, Amsterdam, Lausanne, New York, Oxford, Shannon, Singapore, Tokyo, Chapter 2.

Fanchi, J. F., (2006). “*Principles of Applied Reservoir Simulation*”, Elsevier, Oxford, USA, Chapter 18.

Ghadami, Nader et.al., (2017). “*Enhanced History Matching and Prediction Using Integrated Analytical and Numerical Modeling Approach*”, SPE-186384-MS, SPE/IATMI Asia Pacific Oil & Gas Conference, Jakarta.

Havlena, D., Odeh, A.S., (1964). “*The Material Balance as an Equation of Straight Line*”, Journal of Petroleum Technology, Dallas.

Havlena, D., Odeh, A.S., (1964). “T*he Material Balance as an Equation of Straight-line Part II*”, Journal of Petroleum Technology, Dallas.

Kabir, C.S., et.al., (2003). “*Experiences with Automated History Matching*”, SPE 70670, SPE Reservoir Simulation Symposium, Houston, Texas.

Rukmana, D., Kristanto, D., and Aji, V. Dedi C., (2012). “Teknik Reservoir Teori dan Aplikasi”, Pohon Cahaya, Yogyakarta, Chapter XIII and Chapter XI.

Lake, L., (2014). “Fundamental of Enhanced Oil Recovery”, PennWell Books, Tulsa, Oklahoma.

McCain, William D., (1990). “*The Properties of Petroleum Fluids Second Edition*”, PennWell Books, Tulsa, Oklahoma, Chapter 8.

Ou, Jin, et.al., (2016). “*Dynamic Rock Typing Study of a Complex Heterogeneous Carbonate Reservoir in Oil Field, Iraq*”, SPE-183472-MS, Abu Dhabi International Petroleum Exhibition & Conference, Abu Dhabi.

Pamungkas, J., (2011). “Pemodelan dan Aplikasi Simulasi Reservoir”, First Edition, UPN “Veteran”, Yogyakarta, Chapter III.

Pamungkas, Joko, dan Supit, Roby, "Penyelarasan Data PVT Sumur dengan Menggunakan Software Winprop", Jurnal Ilmu Kebumian Teknologi Mineral, ISSN 0854-2554, Yogykarta, 2007.

Pertamina, 2023., Studi Simulasi Reservoir Chemical EOR Fullscale Lapangan Tanjung Zona ABCD

Pletcher, J.L., "*Improvements to Reservoir Material Balance Methods*", SPE 62882, dipresentasikan di SPE Annual Technical Conference and Exhibition, Dallas, Texas, 2000.

Ramos, M. C., Ortega, J., & Alvarez, M. (2020). Integrating Numerical Simulation and CEOR for Enhanced Oil Recovery. *Journal of Petroleum Science and Technology, 35*(4), 45–60.

Rukmana, Dadang, "Simulasi Reservoir", BPMIGAS - SKK Migas, Bali, 2013.

Tavassoii Z., et. al., "*Errors in History Matching*", SPE 86883, Imperial College, London, 2004.