Scientific Contributions Oil & Gas, Vol. 48. No. 2, August: 53 - 67

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

Optimization of CO_2 Injection Through Cyclic Huff and Puff to Improve Oil Recovery

Dedi Kristanto[1], Hariyadi[1], Eko Widi Pramudiohadi[1], Aditya Kurniawan[2], Unggul Setiadi Nursidik[1], Dewi Asmorowati[1], Indah Widiyaningsih[1] and Ndaru Cahyaningtyas[1]

[1]Petroleum Engineering Department, Faculty of Mineral Technology and Energy, UPN "Veteran" Yogyakarta Padjajaran Condong Catur Street, Yogyakarta, 55283, Indonesia.

[2]Chemical Engineering Department, Faculty of Industrial Engineering, UPN "Veteran" Yogyakarta Padjajaran Condong Catur Street, Yogyakarta, 55283, Indonesia.

Corresponding author: dedikristanto@upnyk.ac.id

Manuscript received: March 31th, 2025; Revised: April 22th, 2025
Approved: May 16th, 2025; Available online: May 21th, 2025; Published: May 22th, 2025.

ABSTRACT - One of the Enhanced Oil Recovery (EOR) strategies in the petroleum industry is CO_2 injection using the huff and puff method. The method is performed on one well that acts as an injection and a production well. The method works by injecting a certain volume of carbon dioxide (CO_2) gas into the reservoir and then closing the well for a period of time. This injection cycle can take place over several cycles. Production can be carried out after one or more cycles according to the design. In this study, CO_2 injection optimization with the huff and puff method is carried out with reservoir simulation (GEM-MG) by taking data from one of the oil and gas wells in Indonesia, with carbonate rock characteristics that are water wet. The simulation work steps include inputting data (fluid, rock properties, and production), initialization, history matching, and CO_2 injection optimization with the huff and puff method. The optimization scenarios include optimization of injection pressure and number of cycles. The injection pressure scenario uses a range of 500 - 3000 psi, based on the simulation results obtained that the injection pressure of 500 psi produces the highest recovery factor (RF) of 22.2%. Then, the cyclic scenario was carried out at the optimum in jection pressure (500 psi) with 2 - 6 cycles. From the simulation results, it is found that the number of cycles for this carbonate reservoir condition does not have a significant effect, as evidenced by the RF values ranging from 22.1 - 22.3%.

Keywords: cyclic CO_2 injection, huff and puff, enhanced oil recovery, compositional simulation.

How to cite this article:

Dedi Kristanto, Hariyadi, Eko Widi Pramudiohadi, Aditya Kurniawan,Unggul Setiadi Nursidik, Dewi Asmorowati, Indah Widiyaningsih and Ndaru Cahyaningtyas, 2025, Optimization of CO_2 Injection Through Cyclic Huff and Puff to Improve Oil Recovery, Scientific Contributions Oil and Gas, 48 (2) pp. 53-67. DOI org/10.29017/scog.v48i2.1659.

INTRODUCTION

The huff and puff method, often referred to as cyclic CO_2 injection, is a technique employed in the oil and gas sector to enhance oil recovery from reservoirs (Abdurrahman et al. 2019; Chandra 2021). This technique entails the repetitive injection of carbon dioxide (CO_2) into the reservoir, allowing the CO_2 to permeate through the reservoir before being extracted back to the surface. The objective of this technique is to enhance the displacement of oil within the reservoir and improve the overall oil recovery (Zhou et al. 2022).

The objective of optimizing CO_2 injection in the context of huff and puff is to enhance the efficiency and effectiveness of the cyclic CO_2 injection process, ultimately leading to increased oil recovery rates from the reservoir (Seyyedsar et al. 2017). Recently, there have been several instances in Indonesia, particularly in the oil and gas sector, where different companies and organizations have experimented with and adopted the huff and puff CO_2 injection method to enhance oil extraction. In October 2022, PT. Pertamina performed a huff and puff CO_2 injection in the JTB Field, while PetroChina International Jabung Ltd. did a field test of huff and puff CO_2 injection at the Gemah-6 well in Jabung working area in December 2022 (Halinda et al. 2023).

The CO_2 huff and puff method comprises various key components and procedures. These activities encompass the readiness of functional components such as mixer tanks, workover rigs, water storage tanks, and CO_2 storage tanks, in addition to informational sessions conducted by management representatives before the commencement of the pumping procedure. The injection process is performed continuously until the desired volume of CO_2 is reached. The overall duration of the injection process may vary based on the unique conditions of the field and the operations being carried out (Halinda et al. 2023).

Research and assessments have been conducted to evaluate the performance and efficacy of CO_2 huff and puff injection optimization. While the huff and puff technique is typically applied using surfactants, this study focuses on applying CO_2 as the stimulation agent. The research primarily aims to assess the outcomes of CO_2 injection using the huff and puff technique in specific oil fields to determine its effect on oil extraction. Additionally, simulation studies have been carried out to evaluate key parameters such as soaking time and the number of injection cycles to the effectiveness of CO_2 huff and puff, particularly in low permeability reservoirs.

Continual trials and research demonstrate a growing interest and dedication to enhancing CO_2 huff and puff injection to enhance oil recovery in the petroleum industry. Moreover, studies on CO_2 injection optimization in Indonesia remain limited (Kartiwa 2017; Abdurrahman et al. 2019; Iskandar et al. 2022; Ramadhan et al. 2024), especially in carbonate rock reservoirs. These reservoirs particularly play a significant role in the petroleum industry because they exhibit a very high degree of heterogeneity due to diagenesis, recrystallization and dissolution processes. This research aims to contribute to the optimization of CO_2 injection using the huff and puff method in carbonate reservoir types with low permeability, and it represents the first application of huff and puff CO_2 injection in the region. This endeavor aims to optimize the utilization of cyclic CO_2 injection to enhance overall oil production from the reservoir and improve the efficiency of oil recovery operations.

CO_2 injection has demonstrated considerable success in numerous field experiments. The huff and puff approach involves utilizing a single well for injection and production. The process consists of three sequential steps: gas injection, shut-in for a designated period, and reopening the well for production (Rotelli et al. 2017). The CO_2 huff and puff project were carried out between 1984 and 1985 in South Louisiana. It involved the implementation of the project in 11 wells across five areas. These projects produced 78,822 barrels of additional oil through CO_2 injection by April 1986 (Palmer et al. 1986). A pilot study utilizing the CO_2 huff and puff method was conducted from December 1984 to December 1986 in the Camurlu field in Turkey. In 1984, three periodic CO_2 injections were administered on two distinct areas, namely Camurlu-11 and Camurlu-22. The average production rate was 18.3 barrels per standard day (STB/D), and the total oil collected for each cycle was 2,043, 4,382, and 7,212 barrels (bbl), respectively (Gondiken, 2007). Two wells, numbered 271 and 272, were drilled in 1977 in two separate structures in Timbalier Bay, USA. Due to inadequate completion and sweep efficiency, CO_2 stimulation was implemented on both wells. In the initial production phase, the maximum production rate was 111 barrels per day (bbl/D), which later increased to 190 bbl/D. The cumulative production during the test period was 5,034 barrels (Simpson 1988). In 1985, a total of 203 treatments were carried out in the Big Sinking field in the US, involving 85,000 Mscf of CO_2 injection. The composite efficiency, measured at 0.83 Mscf/bbl, resulted in an incremental oil recovery of 102,000 bbl through CO_2 stimulation, as reported by Miller in 1990. The inaugural Huff and Puff initiative injection project in Trinidad and Tobago occurred in 1984 at the Reserve Forest oil field with Carbon dioxide (CO_2) sourced directly from the field itself (Zhang et al., 2004). According to Mohammed-Singh (1988), approximately a combined amount of 2,092 million cubic feet of carbon dioxide (CO_2) was injected, resulting in the production of 101,635 barrels of oil from 16 tested wells (Monger & Coma 1988).

The novelty of this study lies in the application of CO_2 huff and puff injection in the JTB field using a sector-based reservoir model centered on the JTB-137 and JTB-161 wells. JTB field has 70 wells located in West Java, Indonesia and discovered at 1968. The main reservoir in this field is a carbonate reservoir.

While previous studies have primarily investigated the huff and puff technique using surfactant, this research explores the use of CO_2 as the stimulation agent and evaluates its performance through fluid flow and composition simulation modeling based on the Peng-Robinson equation of state. The simulation assesses key production parameters, including cumulative water oil ratio (WOR) and gas oil ratio (GOR), and compares them with pre-injection production data. The study novelty also includes fine-tuning the huff and puff design parameters, such as injection rate and soaking duration to optimize oil recovery and improve the overall efficacy of the method at a pilot scale. This targeted optimization approach, informed by simulation-based insight, offers a new perspective on enhancing oil recovery in low permeability reservoirs through CO_2 huff and puff method.

METHODOLOGY

Theory

CO_2 injection mechanism

The primary mechanisms driving oil recovery during CO_2 stimulation include oil swelling, viscosity reduction, and alterations in relative permeability due to the displacement of mobile water by gas. A CO_2 huff and puff operation consists of three stages: gas injection into the well, a shut-in period allowing reservoir interaction and a subsequent production phase. During the injection phase, the injected CO_2 remains immiscible and bypasses the oil by displacing either flowing water or oil. A certain level of water movement is beneficial, as it helps prevent oil displacement from the well. By the end of the injection phase, CO_2 is evenly distributed throughout the reservoir, leading to the mass transfer between the CO_2 and crude oil. The reservoir pressure at the end of the injection cycle is considerably higher than at the start. This increases pressure supporting the substance mixing. However, it is preferable to avoid any dislocations throughout the injection process.

Mass transfer between the crude oil and CO_2 occurs during the suction stage. The volume of the oil phase increases and causes the intermediate hydrocarbons to expand. When there are delays in achieving complete mixing, it is necessary to have a flushing period. However, the optimal duration for flushing can vary widely across different studies and literature sources. During the production stage, oil is extracted through a series of processes, including oil swelling, viscosity reduction, extraction, lowering of interfacial tension (IFT), and changes in relative permeability caused by displacing water by CO_2. Oil swelling occurs uniformly over the contacted region, rather than solely along the flood front as observed in continuous flooding. This leads to an increase in the relative permeability of the oil. According to (Murray et al. 2001), reduced viscosity and lower interfacial tension (IFT) significantly facilitate oil mobilization and flow.

Huff and puff CO_2 injection parameters

With the increasing number of wells that have been enhanced with CO_2, numerous studies are currently being conducted to explore their practical applications in the field. Studies by (Palmer et al. 1986; Monger & Coma 1988; and Haskin & Alston 1989) demonstrate that CO_2 stimulation can improve oil recovery by displacing remaining oil from the reservoir. Furthermore, numerous investigations have focused on identifying the key factors affecting the effectiveness of CO_2 stimulation, including works by (Patton et al. 1982; Hsu & Brugman 1986; Thomas & Monger-McClure 1991).

Patton et al. (1982), performed simulations on reservoirs containing heavy oil and verified that the quantity of injected CO_2 and the number of cycles is the primary significant parameters. According to (Hsu & Brugman 1986), who analyzed actual data from reservoirs in Louisiana, the amount of CO_2 injected is the primary factor affecting oil recovery. In contrast, the duration of adsorption has a comparatively minor impact. The treatment pressure refers to the maximum reservoir pressure that is permissible during the injection process. Increasing the treatment pressure leads to solubility of CO_2 and oil viscosity reduction. Injection pressures of up to 0.7 pounds per square inch per foot depth have yielded positive outcomes in multiple field tests (Patton et al. 1982). Accelerating the injection of CO_2 into the well leads to increased absorption of CO_2 throughout the reservoir, hence facilitating contact with a more significant amount of oil (Palmer et al. 1986).

The quantity of CO_2 injected has been acknowledged as one of the most influential factors in improving oil recovery. Monger & Coma (1988) conducted a study on 14 reservoirs in Louisiana and Kentucky where CO_2 stimulation was undertaken. They found that the amount of CO_2 injected was the most critical factor in heavy and light oil reservoirs. An increased contact volume between the injected CO_2 and the oil enhances oil recovery by promoting greater swelling and reducing viscosity. The duration of the flushing process has an impact on the effectiveness of CO_2 stimulation. During the injection cycle, a portion of the oil is displaced from the well. This displacement necessitates the reintroduction of the oil through the return oil flow before induced oil production can be achieved. Although it is essential to have a flushing time to optimize oil recovery, the duration of the flushing interval does not have a significant impact (Hsu & Brugman 1986).

Methodology

Previous studies created a finite volume simulator that utilizes a versatile 3-D grid to accurately compute variations in wettability and interfacial tension (IFT). Some research related to introducing a technique to increase the scale of laboratory imbibition research. A 1-D model is employed to mimic changes in wettability, and the time scale equation is utilized in up-scaling to achieve the same recovery factor as the original oil-in-place (OOIP) core plug. Hakiki et al. (2015) developed a model for polymer surfactant injection by analyzing core flooding test data. Performed reservoir simulation modeling was conducted to investigate the effects of surfactant injection in carbonate rock formations. They considered various factors such as reservoir heterogeneity, relative permeability, capillary pressure, rock adsorption, wettability alteration, and interfacial tension (IFT) models. In this study of huff and puff CO_2 injection simulation, the preliminary phase involves and develops a model utilizing a single-well method to represent the wells under investigation in the JTB Field. The subsequent phase involves estimating original oil in place and performing history matching using production data from the first well. The final phase of this study is optimizing the huff and puff injection scenarios and evaluating the development strategy at the well scale. The overall research approach and flow chart are illustrated in Figure 1, includes preparing a comprehensive research report, conducting regular consultations, presenting the findings, and providing recommendations based on the results.

RESULT AND DISCUSSION

This study occurred in the JTB field, located in West Java, Indonesia. CO_2 huff and puff injection simulations were conducted on the USN-137 well, which is estimated to meet the screening criteria for CO_2 injection. This well has been in production since 1997, with a cumulative oil production of 8865 bbl. The original oil in place (OOIP) is estimated at 4.9 MMBBL.

Single well model

The model dimension is cylindrical (10x1x10) with 100 grid blocks. The model has a porosity of 16 - 23% and a permeability of 15 - 42 mD. This model represents a single-well of JTB Field proposed for pilot huff and puff of CO_2 injection in a carbonate reservoir. Figure 2 illustrates a cylindrical, single-well setup model used for huff and puff simulation, developed with the GEM CMG compositional simulator.

Data input

Prior to reservoir simulation, input data must be prepared, including reservoir rock and fluid characteristics, production and pressure history, and other supporting variables.

Table 1 provides data on several fluid characteristics, such as critical pressure, critical temperature, acentric factor, and mol weight data for each component. Meanwhile, Table 2 shows the well data of USN-137 used in the simulation. The reservoir rock data employs a specific rock

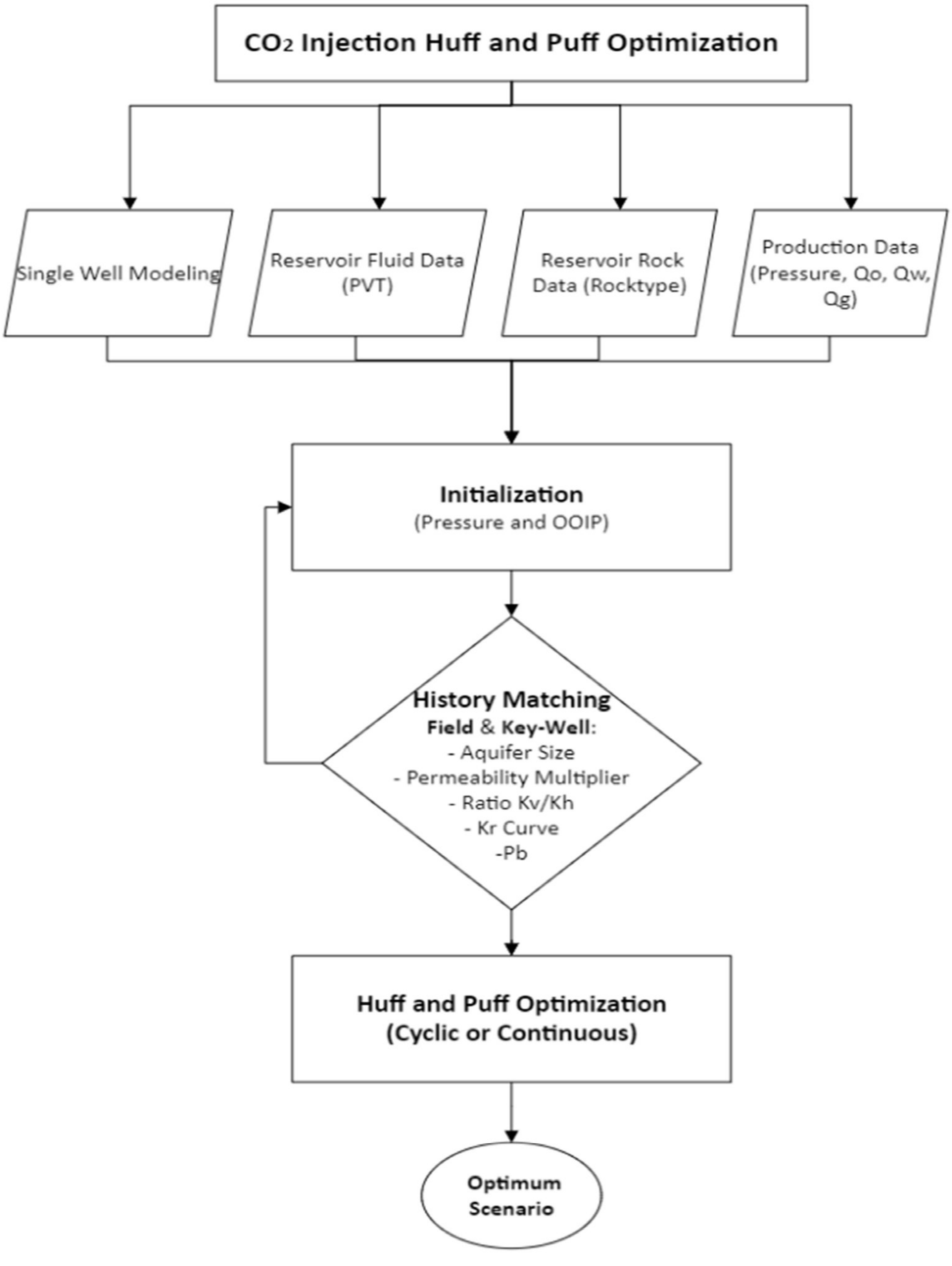

Figure 1. Work flow of activities

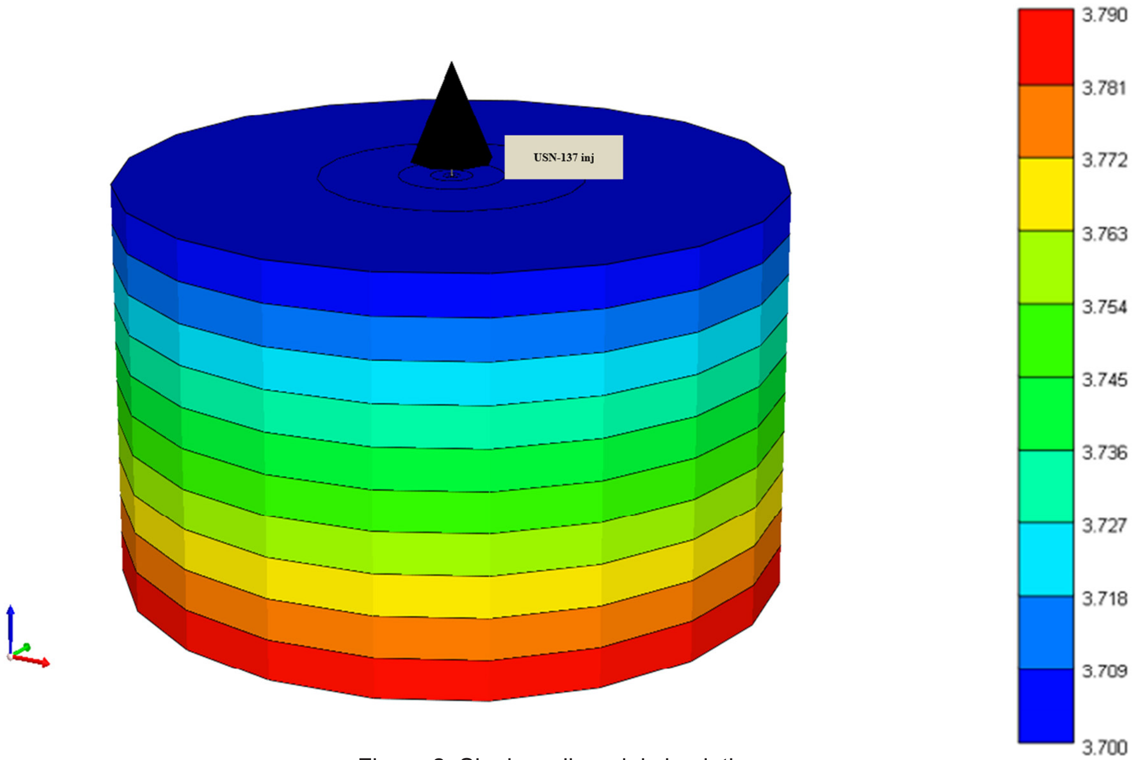

Figure 2. Single well model simulation

Table 1. Fluid characteristics data

No.	Component	Hydrocarbon	Critical pressure, atm	Critical Temperature, ^{0}K	Acentric factor	Mol weight, g/mol
1	CO_2	No	72.80	304.2	0.225	44.01
2	$N_2 – C_1$	No	44.91	187.84	0.012	16.47
3	$C_2 – C_3$	Yes	44.47	340.91	0.128	37.54
4	$C_4 – C_5$	Yes	35.14	440.43	0.216	64.49
5	$C_6 – C_7$	Yes	31.09	545.78	0.251	95.55
6	$C_8 – C_{10}$	Yes	26.90	613.19	0.310	125.19
7	$C_{11} – C_{14}$	Yes	22.38	695.29	0.406	172.28
8	C_{15+}	Yes	15.73	830.35	0.639	30.16

Table 2. Well data of USN-137

Parameters	Value
Reservoir	Limestone
Reservoir pressure, Pr	750 psi
Reservoir temperature, Tr	91 ^{0}C
Porosity, ϕ	16 - 23 %
Permeability, k	15 - 42 mD
Thickness, h	6 ft
Oil gravity	34.29 ^{o}API
Oil viscosity, μ	2.24 cp

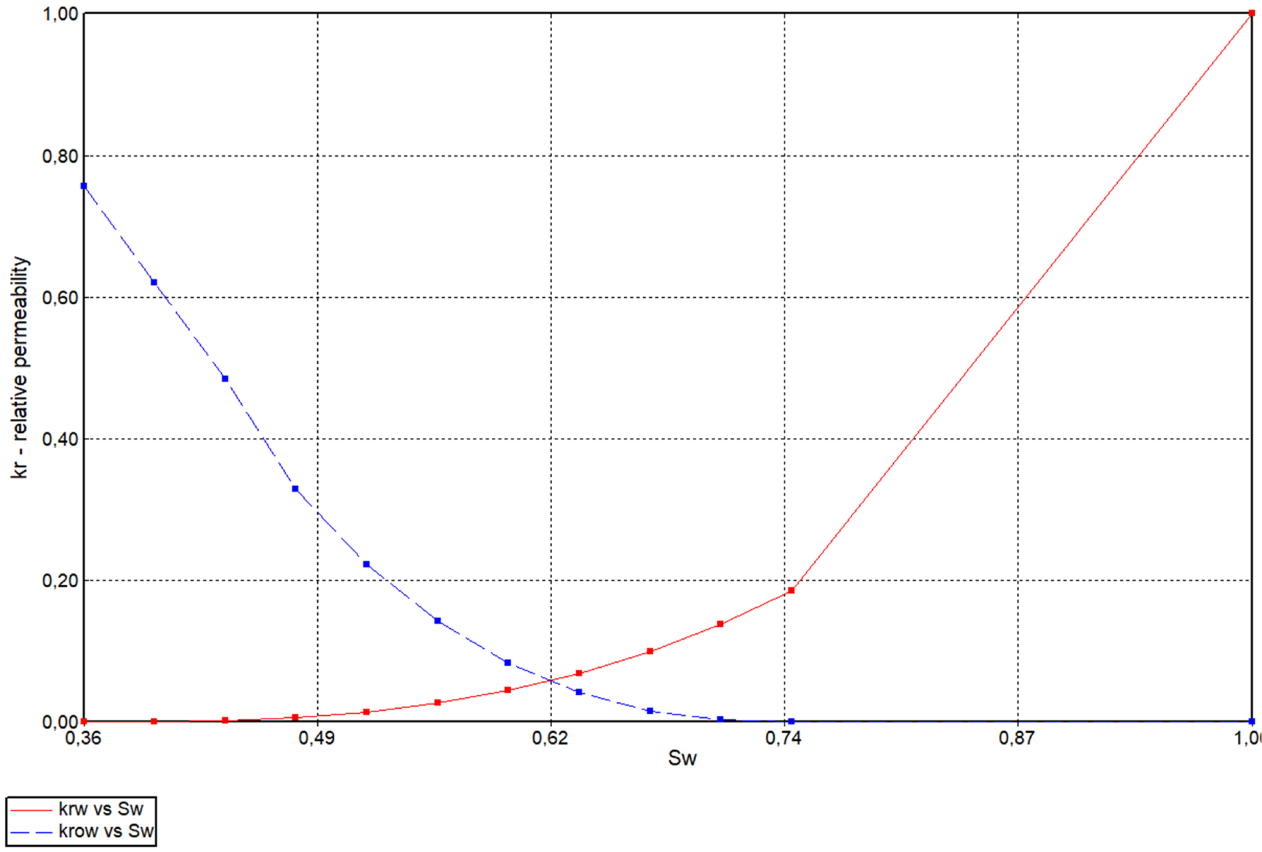

Figure 3. kro-krw vs Sw curve

characteristic known as rock type 1 which exhibits an oil-water relative permeability curve (k_{ro}-k_{rw}) versus water saturation as shown in Figure 3.

Figure 3 shows that the reservoir rock is classified as a water-wet type, where the cross-section is located between the kro-krw curve at a S_w of 0.62. Although, in general, carbonate reservoirs are often said to have oil-wet or mixed-wet tendencies due to long-term interactions with polar components of oil (such as resins and asphaltene) and their complex pore structures. In reality, the wettability of carbonates varies greatly depending on the specific conditions of the reservoir and production history. In some instances, such as the history matching results shown, carbonate rocks can be water-wet due to the strong influence of mineral composition, geochemical conditions of high salinity formation water, and the absence of significant contamination by polar components of light oil. Thus, despite their typical oil-wet classification, carbonate reservoirs can exhibit water-wet properties under exceptional conditions, as illustrated by the relative permeability (kro-krw).

Initialization

The initialization involves identifying the parameters and variables that govern the simulation, ensuring that the model accurately represents the reservoir state at the onset of CO_2 injection or at a designated moment during the injection procedure. Following the initialization, the established conditions must be corroborated and validated against the available field data to ensure that the model accurately represents the reservoir's actual condition. If a discrepancy arise between the model and the field data, further modifications to the initialization parameters are required. The result of

Table 3. Initialization results

Parameter	OOIP (MMSTB)
Volumetric	4.92
Simulation	4.90
% Error	0.4%

original oil in place (OOIP) initialization is shown in Table 3. The initialization continues until the simulated OOIP deviates by no more than 5% from the volumetric estimate.

History matching

The history matching process involves comparing the simulation results and the collected field data to minimize the discrepancies. This is accomplished by iteratively adjusting and optimizing model parameters until the simulated outcomes closely align with observed field behaviour.

This study adjusts the reservoir pressure, relative permeability curve, and aquifer modelling parameters. After the parameters are adjusted, validating the model with more comprehensive data is crucial. Upon completion of the history matching process, it is necessary to review and validate the initial conditions using available field data to confirm that the model accurately represents the actual reservoir conditions in real-time. Thus, the validated model can be utilized to make several predictions, such as the CO_2 injection performance and the planning of the CO_2 injection volume.

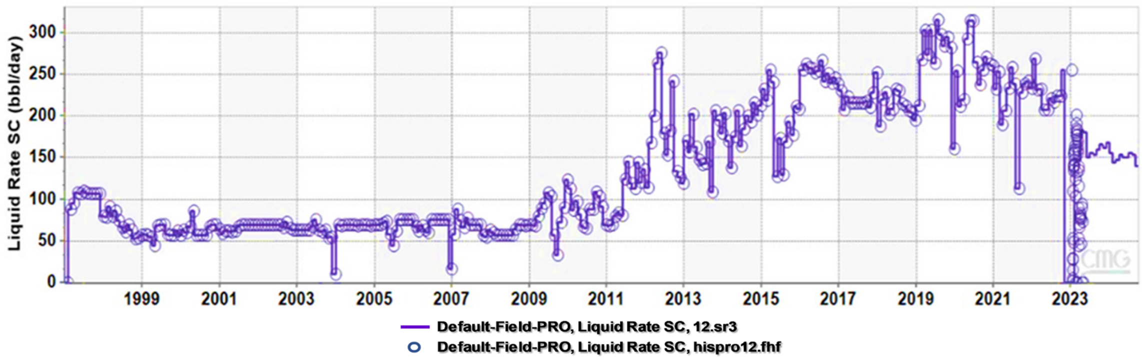

Figure 4. History matching result of liquid rate

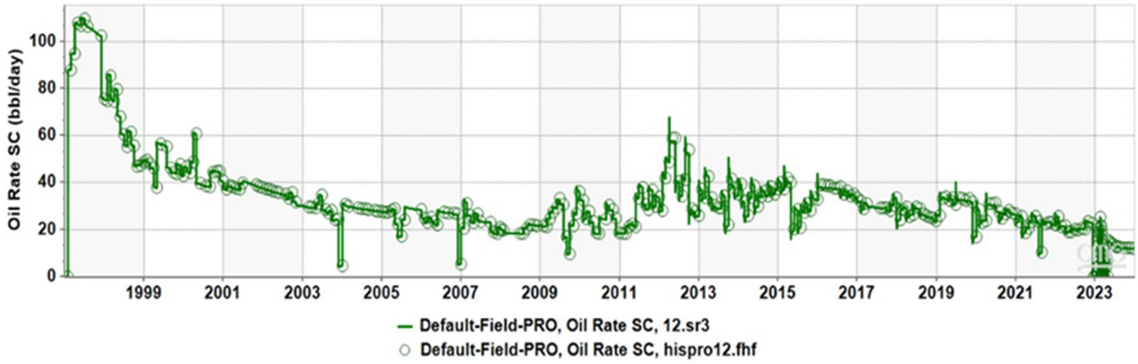

Figure 5. History matching result of oil rate

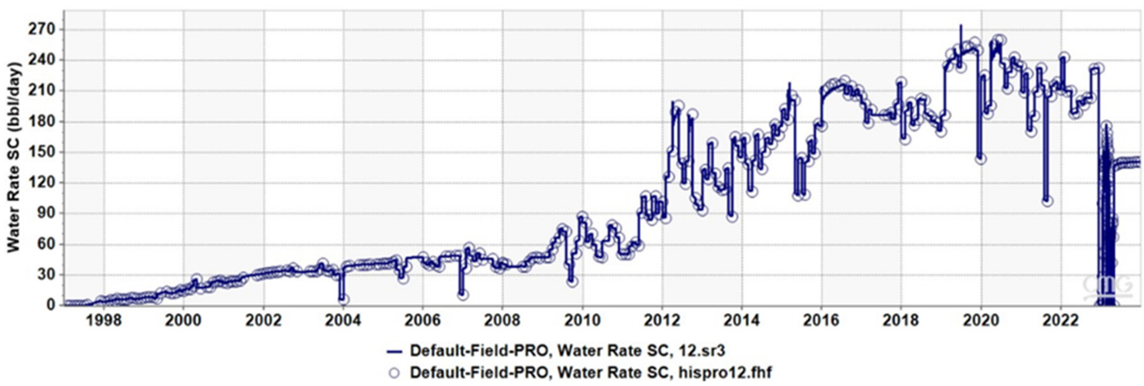

Figure 6. History matching result of water rate

As shown in Figures 4 through 6, the history matching results for liquid, oil, and water production rates demonstrate a strong agreement between the simulated and actual field data, with discrepancies of less than 1%.

Huff and puff optimization

Injection pressure optimization

Injection pressure optimalization is critical in planning and executing CO_2 injection into reservoirs for enhanced oil recovery (EOR) and/or carbon capture utilization and storage (CCUS). The goal is to determine the optimal injection pressure that maximizes the CO_2 flow in the reservoir while considering technological, economic, and environmental constraints. Excessive injection pressure can lead to several issues, such as reservoir formation damage (Li et al. 2022), elevated energy consumption, or the potential leakage of CO_2 to the surface (Jia et al. 2019). On the other hand,

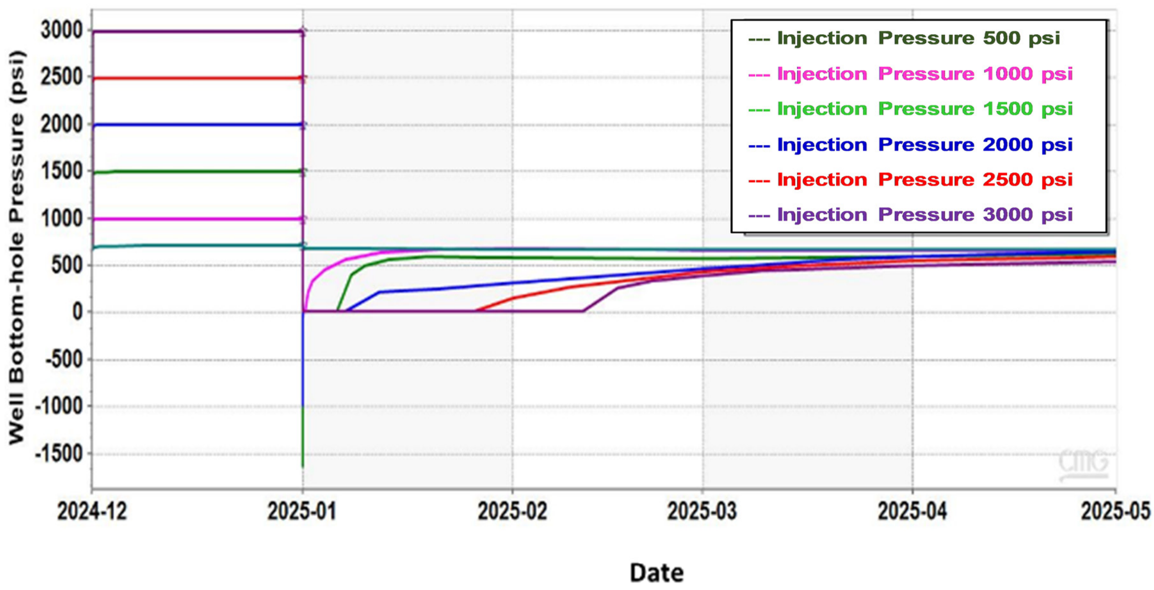

Figure 7. Bottom hole pressure at various pressure injection

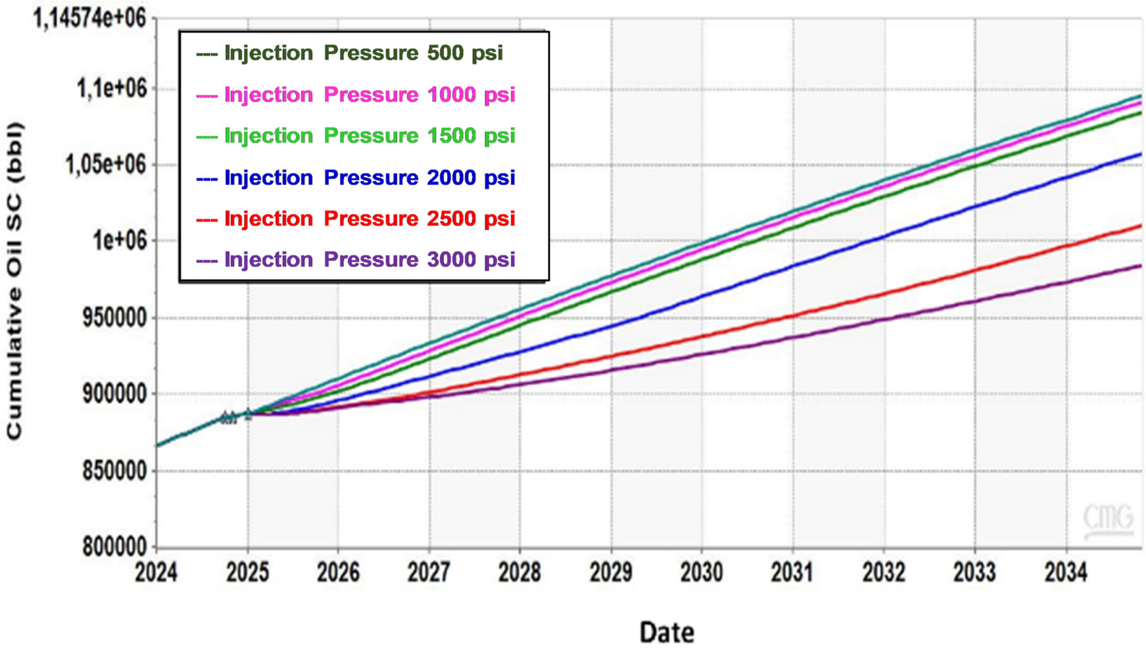

Figure 8. Cumulative oil production at various injection pressure

insufficient pressure might diminish the effectiveness of the injection, resulting in less effective CO_2 mobilization inside the reservoir, as shown in Figure 7. At higher injection pressures, CO_2 is more efficient at mixing with oil and increases reservoir sweeping. This results in the highest cumulative oil production. CO_2 injection efficiency is reduced at lower pressure, reducing oil volume. CO_2 injection is only effective if the injection pressure is above the minimum miscibility pressure (MMP). If the pressure is below the MMP, CO_2 cannot mix effectively with the oil, resulting in decreased EOR efficiency. Figure 8 shows that lower injection pressures lead to reduced production, potentially due to the inability to achieve MMP. Higher CO_2 injection pressures result in more excellent cumulative oil production but at a higher operational cost. The selection of injection pressure should consider minimum miscibility pressure, as well as the optimization of production yield and operation costs. This graph is important for predicting CO_2 injection efficiency in a particular oil field and developing an optimal production strategy.

Higher CO_2 injection pressures provide a significant initial surge, resulting in higher and more stable oil production rates in the long term, as shown in Figure 9. The initial surge at high pressures demonstrates the importance of CO_2 injection to improve oil recovery efficiency. Decision-making on injection pressure should consider cost, technical efficiency, and reservoir characteristics.

The simulation result above shows that 500 psi is the optimum CO_2 pressure for the current scenario, where the summary result for injection pressure scenarios presented in Table 4.

The experimental result by (Zhou et al. 2022) experimental and mathematical studies were carried out to investigate heavy oil production performance using the carbon dioxide (CO2 shows that higher injection pressure (5000 kPa) is preferred due to a higher recovery factor, however, at lower pressure, 3500 kPa, the average production rate for each cycle can be maintained. Besides, the pressure depletion rate also significantly contributes to the overall recovery factor (Zhou et al. 2022)experimental and mathematical studies were carried out to investigate heavy oil production performance using the carbon dioxide CO_2 (Hence, Bungsu et al. 2018) explained that the maximum injection pressure for JTB must not exceed 2000 psi to avoid any fracture induced by the gas injection.

Table 4. Injection pressure scenarios

Injection Pressure Scenarios, psi	Np, MMSTB	Recovery Factor, %
500	1.09	22.2
1000	1.057	21.6
1500	1.056	21.6
2000	1.051	21.4
2500	1.01	20.6
3000	0.98	20.0

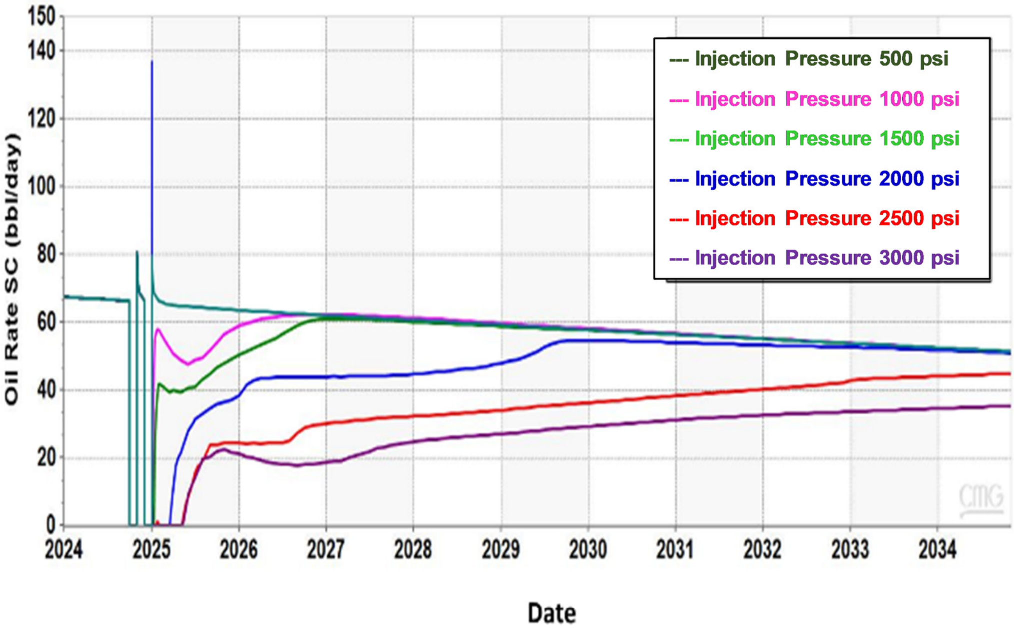

Figure 9. Oil rate at various injection pressure

Cyclic huff and puff optimization

Cyclic huff and puff primarily seek to enhance the mobility of oil confined inside the reservoir by utilizing CO_2, which possesses superior solubilization capabilities to oil. The CO_2 will amalgamate with the oil, diminish its viscosity, elevate the pressure within the reservoir, and propel the oil toward the production well.

Fundamental procedure of huff and puff cyclic CO_2 injection (Huff): CO_2 is initially introduced into the reservoir through an injection well to elevate the reservoir pressure and diminish the oil viscosity. Soaking phase: Following the completion of the injection, this phase permits the CO_2 to amalgamate with the oil in the reservoir. In the soaking phase, CO_2 solubilizes the oil, diminishes viscosity, and facilitates smoother oil flow. Production (Puff) phase: Following the soaking phase, oil extraction commences by elevating the CO_2 stressed oil to the surface. This production is generally elevated due to the enhanced mobility of the oil following the CO_2 infusion which decreases viscosity. Cycle Reiteration phase: This procedure is executed multiple times. Each cycle allows for increased oil recovery from the reservoir, contingent upon the efficacy of CO_2 in diminishing the oil viscosity and facilitating its movement to the production well.

Several aspects must be evaluated to enhance cyclic huff and puff for CO_2 injection, including cycle time, injection pressure, and soaking period. This optimization enhances oil recovery while minimizing CO_2 emissions and operational expenses. The soaking length is essential, allowing CO_2 to break down the oil and decrease its viscosity. An insufficient duration may hinder adequate CO_2 integration with the oil, whilst an excessive duration may result in suboptimal CO_2 utilization. Evaluating the ideal soaking duration is crucial for optimizing oil extraction. Reservoir modelling enables the calculation of soaking duration by analyzing CO_2 flow data and oil viscosity to determine the perfect equilibrium point.

The CO_2 injection pressure must adequately surpass reservoir pore pressure and diminish oil viscosity without inducing fractures in the reservoir rock. Consequently, the optimization of injection pressure is crucial. To optimize the advantages of CO_2 injection, it is critical to maintain the CO_2 in a supercritical state since this form exhibits enhanced solubility and more efficiently diminishes oil viscosity. The injection pressure must exceed 7.38 MPa to attain the supercritical state. The volume of CO_2 injected per cycle must be optimized. Insufficient amounts may hinder optimal oil recovery, whilst excessive volume might result in elevated CO_2consumption and increased operational expenses. A simulation model is crucial for estimating the CO_2 required each cycle to minimize CO_2 consumption and enhance oil recovery.

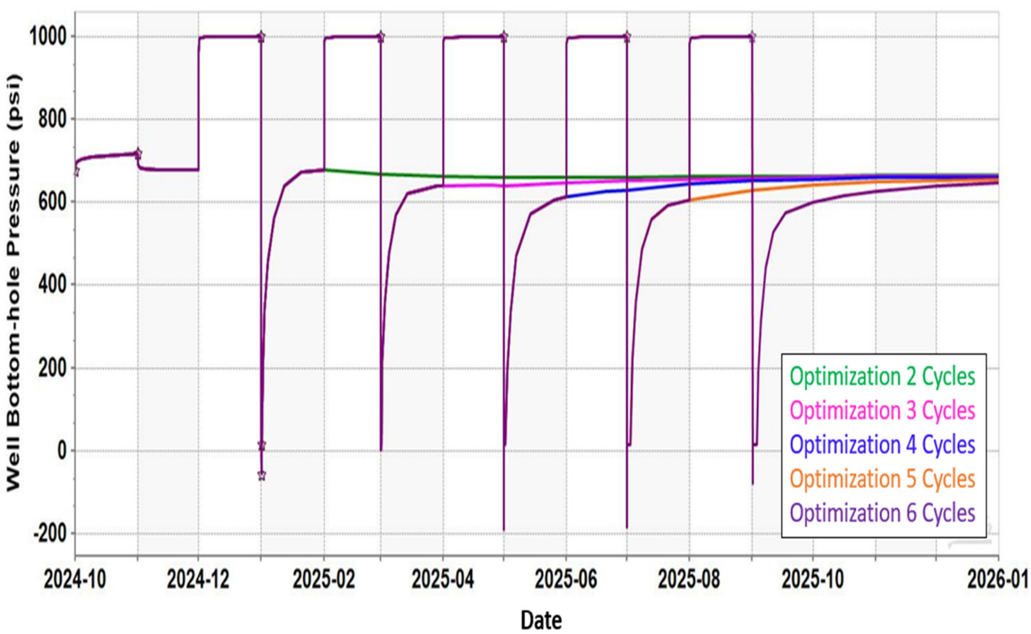

Figure 10. Bottom hole pressure at various cyclic huff and puff

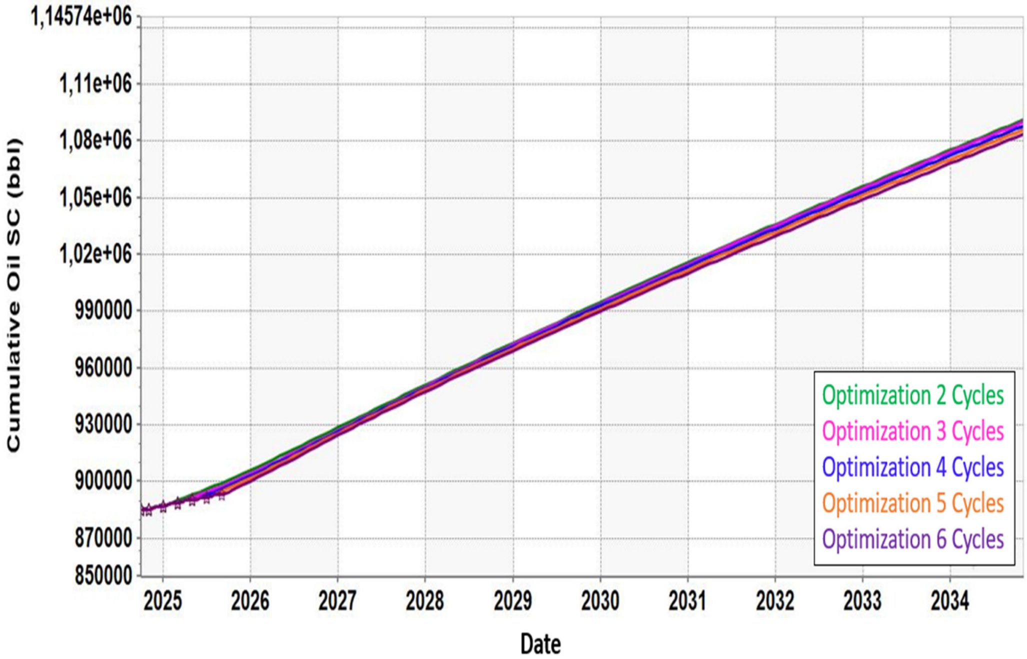

Figure 11. Cumulative oil at various cyclic huff and puff

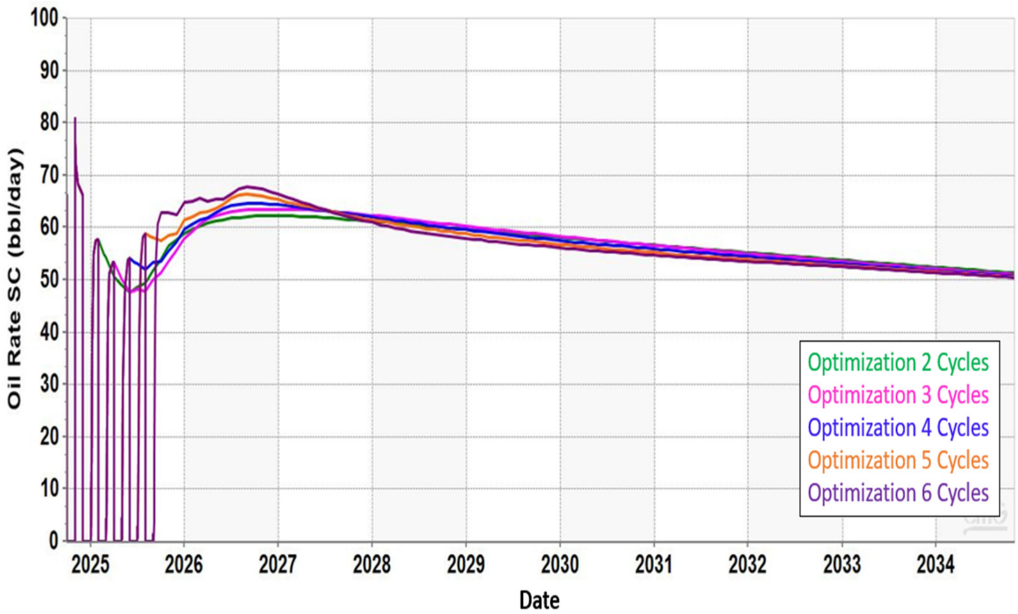

Figure 12. Oil rate at various cyclic huff and puff

Reservoir modelling was employed to evaluate multiple huff and puff cyclic scenarios, incorporating soaking length, CO_2 content, and cycle frequency modifications. As optimization cycles increase, the complexity of borehole pressure (BHP) fluctuations escalates, resulting in elevated peak pressures and extended stabilization periods. Incorporating cycles facilitates enhanced CO_2 sweeping within the reservoir; however, it may also lead to increased operational duration and expenses.

Figure 10 indicates that during the initial cycles (2-3 cycles), there is a more pronounced drop in BHP pressure, corresponding to an accelerated oil production rate. During advanced cycles (4-6), the reservoir exhibits an extended duration to achieve stable pressure, signifying a more profound oil depletion process. The selection of the number of cycles must consider the equilibrium between oil production yield and the incremental operational cost associated with each cycle. Increasing the number of cycles optimizes the CO_2 injection effect; however, achieving pressure stability in each cycle requires a longer duration. The cyclic huff and puff method utilizing CO_2 injection demonstrates an increase in pressure during the injection phase, followed by a decrease in pressure during the production phase. Increasing optimization cycles results in more intricate pressure dynamics, leading to extended pressure stabilization and enhancing the potential for improved oil recovery. Determining the optimal number of cycles requires an evaluation of technical efficiency, operating costs, and reservoir characteristics.

Cumulative oil production exhibits an upward trend with the number of cycles; however, the rate of increase demonstrates diminishing returns. Increased cycles yield optimal output over an extended period; however, evaluating them concerning cost and operational efficiency is essential. Figure 11 serves to identify the optimal cycle count that maximizes cumulative oil production while maintaining manageable operating expenses.

Figure 12 illustrates significant variations in oil production rates during the initial phase across all cycle scenarios. This phase corresponds to the initial injection stage, where the oil displacement is primarily driven by the pressure of the newly injected CO_2. Scenarios with a higher number of cycles (5 and 6 cycles) demonstrates a more consistent increase in production rate than a lower number of cycles. Following the initial fluctuations, oil production rates are expected to decline and gradually stabilize between 2027 and 2034. An increased number of cycles leads to elevated and more consistent production rates than a reduced number of cycles. The increase in production rate remains observable at additional cycles (5 and 6 cycles), albeit to a lesser extent. The data suggests that the reservoir continues to respond to CO_2 injection despite decreased efficiency during later cycles. From the simulation above, the most optimum cycle number is two cycles. The result summary of cycle scenario is presented in Table 5.

Table 5. Cycle scenarios

Cycle Scenarios	Np, MMSTB	Recovery Factor, %
2	1.091	22.3
3	1.090	22.2
4	1.088	22.2
5	1.086	22.1
6	1.084	22.1

CONCLUSION

The optimization of CO_2 injection with the huff and puff cycle methodology is an exceptionally efficient method for enhancing oil recovery, particularly in low-permeability or long-producing reservoirs. This technique increases production efficiency by employing CO_2 to lessen oil viscosity and augment its flow. Based on simulation result, for USN-137, which is characterized by carbonate rock and water-wet properties, CO_2 injection using huff and puff method results for the optimum injection pressure scenario at a low injection pressure (500 psi). Under this condition, a recovery factor of 22.2% was achieved using 2 - 6 injection cycles. The improved performance at low pressure is attributed to more uniform diffusion and reduced risk of gas channelling or gas blocking in the reservoir. However, in the number of cycles scenario, the results obtained did not have a significant effect, as evidenced by the RF values ranging from 22.1 - 22.3%. These findings suggest that cycle number may be a less sensitive parameter under these specific conditions. This research provides a useful reference for the application of CO_2 huff and puff methods in similar well and highlights the need for further investigation into other operational parameter such as soaking time or shut-in duration.

ACKNOWLEDGMENT

The authors would like to thank the Petroleum Engineering Department, the Chemical Engineering Department, and PT Pertamina EP for their support and facilitation of this research. Gratitude is also extended to Research Center and Community Services (LPPM) UPN "Veteran" Yogyakarta for funding this study.

GLOSSARY OF TERMS

Symbol	Definition	Unit
CO_2	Carbon dioxide	
EOR	Enhanced Oil Recovery	
STB	Stock tank barrel	
bbl	Barrel	
bbl/D	Barrel/day	
Mscf	Thousand standard cubic feet	
WOR	Water oil ratio	bbl/bbl
GOR	Gas oil ratio	scf/bbl
CMG	Computer Modelling Group	
OOIP	Original Oil in Place	MMSTB
CCUS	Carbon Capture Utilization and Storage	
MMP	Minimum miscibility pressure	psi
Np	Cumulative production	MMSTB

REFERENCES

Abdurrahman, M., Ferizal, F. H., Saputra, D. D. S. M. & P. Sari, R., 2019, Study on CO_2 Soaking Time and Huff and Puff Injection Cycle Effect in Tight Permeability Reservoir. Scientific Contributions Oil and Gas, 42(1), 9-14. https://doi.org/10.29017/scog.42.1.388.

Bungsu, S., Primasari, I., Purba, F.I. & Aliefan, T.A., 2018, CO_2 Injection by Huff and Puff at Jatibarang Field. Prosiding Simposium IATMI 2018.

Chandra, S. et al., 2021, Well Integrity Study for WAG Application in Mature Field X, South Sumatra Area for the Fulfillment as CO_2 Sequestration Sink. 107-121.

Gondiken, S., 2007, Camurlu Field Immiscible CO_2 Huff and Puff Pilot Project. https://doi.org/10.2523/15749-ms.

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.

Halinda, D., Az Zariat, A., Muraza, O., Marteighianti, M., Setyawan, W., Haribowo, A., Rajab, M., Firmansyah, M., Hasan, I., Nurlia, D., Adham, A., Prabowo, P., Okabe, H., Mikami, K., Kento, K., Susanta, P. & Palupi, A.S., 2023, CO_2 Huff and Puff Injection Operation Overview in Jatibarang Field Lessons Learned from a Successful Case Study in Mature Oil Field. Society of Petroleum Engineers - ADIPEC, ADIP 2023. https://doi.org/10.2118/216175-MS.

Haskin, H.K. & Alston, R.B., 1989, An Evaluation of CO_2 Huff "n" Puff Tests in Texas. Journal of Petroleum Technology, 41(02), 177-184. https://doi.org/10.2118/15502-PA.

Hsu, H.H. & Brugman, R.J., 1986, CO_2 Huff-Puff Simulation Using a Compositional Reservoir Simulator. Society of Petroleum Engineers of AIME, (Paper) SPE.

Iskandar, U.P., Sofyan, S. & Usman, U., 2022, Ranking of Indonesia Sedimentary Basin and Storage Capacity Estimates for CO_2 Geological Storage. Scientific Contributions Oil and Gas, 34(2), 149-156. https://doi.org/10.29017/scog.34.2.801.

Jia, B., Tsau, J.S. & Barati, R., 2019, A review of the current progress of CO_2 injection EOR and carbon storage in shale oil reservoirs. Fuel, 236, 404-427. https://doi.org/10.1016/j.fuel.2018.08.103.

Kartiwa, C.Y., 2017, 2 of 5 Research and Development Centre for Oil & Gas Technology LEMIGAS Proposed CO_2 Hydrate Technology Application for Carbon Capture and Storage Implementation in Indonesia. Scientific Contributions Oil and Gas, 40(2), 69-73.

Li, J., Chen, Z.Y., Feng, Y.C., Qu, L.S., Liu, J. G., Li, W.Y. & Dai, M.Y., 2022, Damage of reservoir rock induced by CO_2 injection. Petroleum Science, 19(4), 1674-1681. https://doi.org/10.1016/j.petsci.2022.03.016.

Monger, T.G. & Coma, J.M., 1988, Laboratory and field evaluation of the CO_2 huff "n" puff process for light-oil recovery. SPE Reservoir Engineering (Society of Petroleum Engineers), 3(4), 1168-1176. https://doi.org/10.2118/15501-pa.

Murray, M.D., Frailey, S.M. & Lawal, A.S., 2001, New Approach to CO_2 Flood: Soak Alternating Gas. SPE Permian Basin Oil and Gas Recovery Conference, SPE-70023-MS. https://

doi.org/10.2118/70023-MS.

Palmer, F.S., Landry, R.W. & Bou-Mikael, S., 1986, Design and implementation of immiscible carbon dioxide displacement projects (CO_2 Huff-Puff) in South Louisiana. Proceedings - SPE Annual Technical Conference and Exhibition. https://doi.org/10.2523/15497-ms.

Patton, J.T., Coats, K.H. & Spence, K., 1982, Carbon Dioxide Well Stimulation: Part 1-A Parametric Study. Journal of Petroleum Technology, 34(08), 1798-1804. https://doi.org/10.2118/9228-PA.

Ramadhan, R., Mon, M.T., Tangparitkul, S., Tansuchat, R. & Agustin, D.A., 2024, Carbon capture, utilization, and storage in Indonesia: An update on storage capacity, current status, economic viability, and policy. Energy Geoscience, 5(4),100335. https://doi.org/https://doi.org/10.1016/j.engeos.2024.100335.

Rotelli, F., Blunt, J.M., De Simoni, M., Dovera, L., Rotondi, M. & Lamberti, A., 2017, CO_2 injection in carbonate reservoirs: Combining EOR and CO_2 storage. Offshore Mediterranean Conference and Exhibition 2017, OMC 2017, 1-16.

Seyyedsar, S.M., Farzaneh, S.A. & Sohrabi, M., 2017, Investigation of Low-Density CO_2 Injection for Enhanced Oil Recovery. Industrial and Engineering Chemistry Research, 56(18), 5443-5454. https://doi.org/10.1021/acs.iecr.7b00303.

Simpson, M.R., 1988, CO_2 Huff `N` Puff Process in a Bottomwater-Drive Reservoir. JPT, Journal of Petroleum Technology, 40(7), 887-893. https://doi.org/10.2118/16720-PA.

Thomas, G.A. & Monger-McClure, T.G., 1991, Feasibility of Cyclic CO_2 Injection for Light-Oil Recovery. SPE Reservoir Engineering, 6(02), 179-184. https://doi.org/10.2118/20208-PA.

Zhang, Y.P., Sayegh, S.G., Huang, S. & Dong, M., 2004, Laboratory investigation of enhanced light-oil recovery by CO_2/flue gas huff-n-puff process. Canadian International Petroleum Conference 2004, CIPC 2004, 3, 1-13.

Zhou, X., Li, X., Shen, D., Shi, L., Zhang, Z., Sun, X. & Jiang, Q., 2022, CO_2 huff-n-puff process to enhance heavy oil recovery and CO_2 storage: An integration study. Energy, 239, 122003. https://doi.org/10.1016/j.energy.2021.122003.