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Modeling of CO_2 injection scenarios in carbonate reservoir as carbon capture and utilization storage program in the Jatibarang oil field

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Abstract

Carbon dioxide (CO_2) gas injection is one of the carbon capture utilization and storage (CCUS) programs implemented in the Jatibarang oil field, not only for reducing the effects of emissions on the environment but also for increasing oil recovery. CO_2 injection scenarios are simulated herein, considering carbonate reservoirs with a high degree of heterogeneity. By modeling the reservoir, the behavior of the reservoir fluid is observed, and the optimal injection scenario that produces the highest oil recovery is determined. CO_2 injection involves several key parameters, including the injection pattern and injection pressure, which are varied to improve the performance and increase oil recovery. Injection pressures are assessed in the range of 500–3000 psi, and five patterns are considered: staggered drive, line drive, direct line, four spot, and five spot. From the simulations, a staggered drive pattern with an injection pressure of 2500 psi is optimal, reaching a recovery factor of 27.24%. The changes in the oil viscosity and oil saturation distribution before and after CO_2 injection are also obtained.

Keywords: CO_2 injection, Enhanced oil recovery, Optimization, Pattern modeling, Recovery factor.

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1. Introduction

To achieve net zero emissions by 2060, Indonesia is taking serious steps to adopt laws that promote the development and deployment of carbon capture utilization and storage (CCUS) technologies. The Indonesian government has published several significant rules that will serve as the foundation for CCUS implementation in the oil and gas sectors. In particular, Minister of Energy and Mineral Resources Regulation No. 2 of 2023 governs the application of CCUS in upstream oil and gas company activities. CCUS technology is the primary tool used for decreasing carbon emissions in the industrial sector, particularly the oil and gas industry [1, 2].

Carbon dioxide (CO_2) is a critical carbon-based compound because it is becoming increasingly abundant and contributes to global warming, leading to detrimental environmental impacts [3]. Thus, enhanced oil recovery (EOR) operations have been developed, not only to mitigate oil losses and improve mining efficiency but also to reduce CO_2 emissions [4, 5]. Notably, CO_2 injection has become a major method among the various CCUS activities [3, 6] and is one of the EOR methods widely researched and applied in various oil fields worldwide [2, 5]. This approach is thought to improve the oil recovery factor (RF) by reducing viscosity, promoting oil expansion, and elevating the reservoir pressure [7, 8]. Nonetheless, CO_2 injection has not been fully optimized, mainly owing to the complicated fluid transfer mechanisms in reservoirs, which remain poorly understood [9, 10]. One strategy to enhance the comprehension of the CO_2 injection process is reservoir modeling, which is used in the present study to facilitate a comprehensive investigation of the diverse parameters influencing efficacy.

CO_2 gas exhibits multi-contact miscibility with reservoir fluids, thus improving the fluid properties [5]. CO_2-EOR flooding mechanisms include miscible and immiscible processes. The process is called miscible if CO_2 dissolves in the oil, which on the one hand, can decrease its viscosity, density, and residual oil saturation, but on the other hand, increases its mobility. Meanwhile, the process is called immiscible when the CO_2 is only used to push the oil bank from a specific well to the existing production wells [11].

Carbonate reservoirs have distinct geological properties relative to sandstone reservoirs, particularly regarding porosity, permeability, and heterogeneity [12]. The significant variation in carbonate rocks complicates fluid circulation throughout the reservoir, requiring a more comprehensive investigation for CO_2 injection [13]. A major difficulty in developing carbonate reservoirs is the rapid decrease in formation pressure due to unregulated extraction, resulting in unstable oil production. Consequently, a suitable development strategy is essential to sustain stable production and maximize the oil RF [14].

The utilization of CO_2 injection as an EOR technology in Indonesia remains under investigation, and numerous studies have assessed the efficacy of this strategy in domestic oil reservoirs, including feasibility studies [15, 16] and technical research [4, 17]. A preliminary study was performed in the M field in 2010, employing the huff and puff technique to enhance oil output. The research employed reservoir simulations to evaluate many injection scenarios, encompassing variations in the water injection rate, CO_2 injection rate, water injection duration, and soaking period. The findings indicated that the method may enhance oil production by 12% relative to the original production phase and decrease oil viscosity by 70% [18-20].

The main processes involved in oil recovery during CO_2 injection include oil swelling, decreased viscosity, and changes in relative permeability caused by the displacement of mobile water with CO_2 [21]. A CO_2 huff and puff operation involves injecting gas into the well, then shutting in the well to create suction, followed by a production phase [22]. During the injection phase, the injected CO_2 remains immiscible and bypasses the oil by displacing either the flowing water or oil. A certain level of water movement is beneficial because it helps avoid oil displacement from the well. Hence, the CO_2 eventually becomes evenly distributed throughout the reservoir, leading to mass transfer between the CO_2 and crude oil. The pressure in the reservoir at the end of the injection cycle is considerably higher than at the beginning, which promotes mixing between substances. 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. Then, during the production stage, oil is extracted through a series of processes, namely oil swelling, viscosity reduction, extraction, reducing the interfacial tension, and changes in relative permeability caused by the displacement water with CO_2 [23].

A comparable investigation was performed in the Jatibarang field, overseen by Pertamina EP and situated in Cirebon, West Java [24]. The field comprises five levels, with an original oil in place (OOIP) of 446 MMbbl and an oil RF of 22.3% as of 2017. In 2022, a CO_2 injection investigation utilizing the huff and puff method was performed in two producing wells within the F layer. The CO_2 injection was conducted immiscibly at a maximum pressure of 2000 psi, below the formation fracturing pressure (2075 psi) and the minimum miscibility pressure of the F layer (2800 psi). The results revealed a 17 MMbbl rise in oil output.

Based on a previous study, an oil field in Indonesia successfully injected CO_2 using the huff and puff method. The present study builds on that case to optimize the CO_2 injection pressure and pattern using reservoir simulations. Specifically, this study examines the impacts of the injection configuration (i.e., pattern) and injection pressure on oil RF. This work aims to identify the optimal CO_2 injection scenario for the carbonate reservoirs in the Jatibarang oil field and enhance the understanding of its application on a broader scale.

2. Methodology

This study's methodology is illustrated in Figure 1, commencing with data collection (i.e., geological, petrophysical, reservoir fluid, production, and well data). The data are subsequently utilized to construct a reservoir model employing GEM-CMG simulation software [25].

After developing the reservoir model, multiple CO_2 injection scenarios are simulated to evaluate their impact on oil production. The simulation outcomes are assessed by examining critical aspects, such as variations in the reservoir pressure, CO_2 distribution within the reservoir, and oil RF. The simulation scenario that yields the greatest enhancement in production and satisfies the optimization requirements is deemed optimal. Nevertheless, if the outcomes fail to satisfy the requirements, adjustments are made to the injection pattern and pressure, until the best situation is achieved. CO_2 injection pressures of 500–3000 psi are evaluated, and five injection patterns are considered: staggered drive, line drive, direct line, four spot, and five spot.

Screening criteria are required for all immiscible and miscible injection methods. Data from all injection projects worldwide have been tested, and the optimal reservoir/oil characteristics for project success have been recorded. The oil gravity ranges of existing injection methods have been compiled. Moreover, EOR reservoir screenings are performed using previously reported criteria [26] as shown in Table 1. The criteria are set for various parameters: API gravity, oil viscosity, current pressure, temperature, oil saturation, remaining oil, formation depth, thickness, porosity, permeability, and rock type. All of these reservoir parameters should be screened to determine whether they fulfill the criteria and are suitable for CO_2 injection. These results form the basis of the field results and oil recovery mechanisms [27, 28]. Overall, the main objective of the CO_2-EOR screening is to identify existing depleted oil reservoirs that are suitable for CO_2 injection [11].

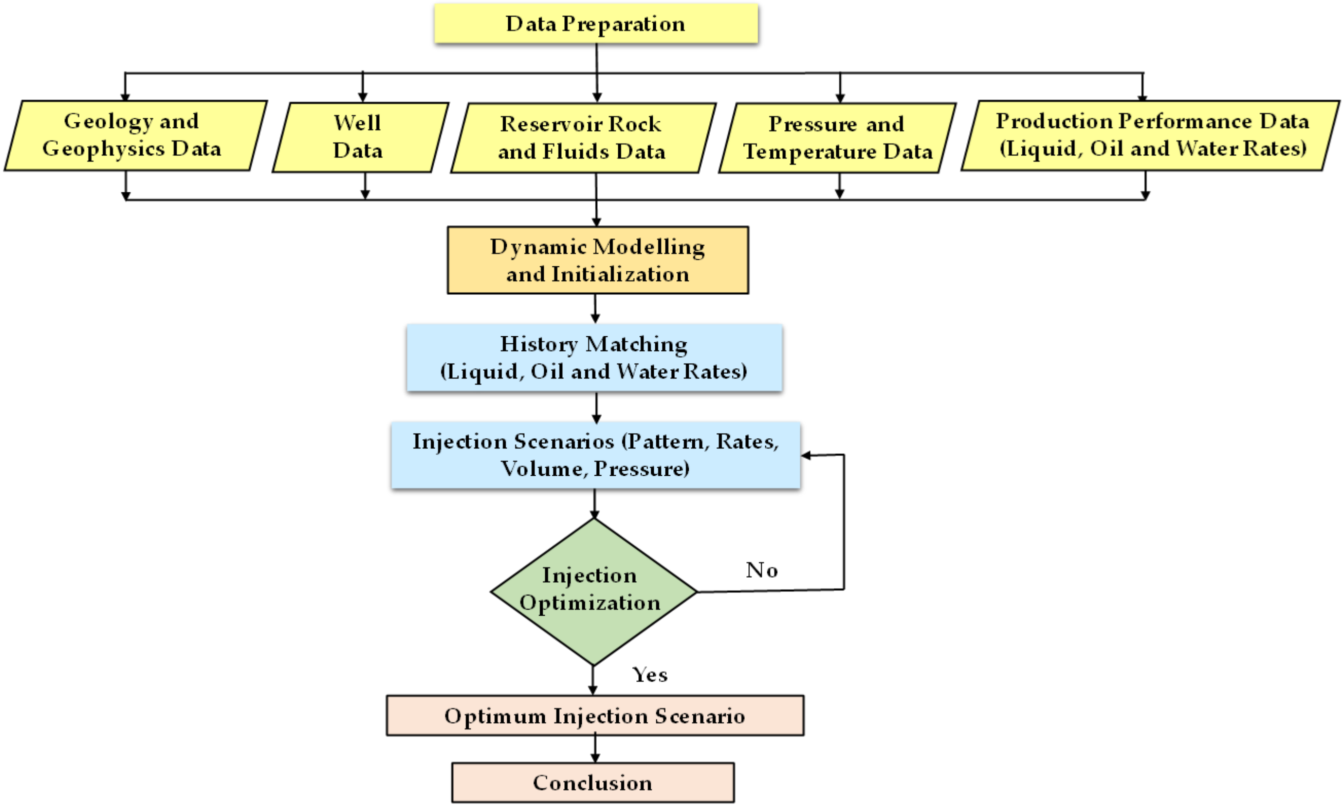

Figure 1.
Flowchart of the study.

Table 1.
Screening criteria of CO_2 injection [26-28].

Reservoir Criteria	Immiscible Flood		Miscible Flood		Chemical Injection			Thermal Injection	
	Water Flooding	**Gas Flooding**	**CO_2**	**N_2 (Inert Gas)**	**Surfactant**	**Alkaline**	**Polymer**	**Steam Flooding**	**In-situ Combustion**
Reservoir Characteristics									
Type of Lithology	Sandstone and Limestone	Sandstone and Limestone	Sandstone or Limestone with minimum	Sandstone or Limestone with minimum	Sandstone (more prefer)	Sandstone (more prefer)	Sandstone (more prefer)	Sandstone	Sandstone
Porosity, %	>10	>10	NC	NC	>15	NC	>15	High Porosity	High Porosity
Oil Saturation (% PV)	>30	>20	>40	>40	>35	>35	>50	>40	>50
Permeability, mD	NC	NC	NC	NC	NC	>10	>100	>200	>50
Thickness, ft	NC	NC	Relatively thin, unless formation dip is low	Relatively thin, unless formation dip is high	NC	NC	NC	>20	>10
Well Depth, ft	NC	>1800	>2500	>6000	<8000	<9000	<9000	<11500	>4500
Temperature, °F	NC	NC	NC	<175	<200	<200	<200	>200	>100
Reservoir Fluids Properties									
Oil Gravity, °API	>20	>12	>22	>35	>20	>20	>15	8-13.5	>10
Oil Viscosity, cp	<35	<600	NC	<0.4	<35	<35	<150	<20000	<5000
Oil Composition	NC	NC	High percent of C_5 to C_{12}	High percent of C_1 to C_7	Light to Intermediate	Light to Intermediate	NC	NC	Some Asphaltic Components

3. Result and Discussion

3.1. CO_2 Injection Modeling

A corner point model is constructed with dimensions of 11 × 11 × 6 and 972 grids, a porosity of 17%, and a permeability of 100 mD. The model represents a single well from the field under study that has been proposed for the huff and puff CO_2 injection pilot project. Figure 2 shows the modeling of a single well simulation using a compositional simulator. This study utilizes data from the USN-137 well, as shown in Table 2, and the reservoir and production statistics of the USN-137 well satisfy the screening criteria for CO_2 injection, as outlined in Table 1.

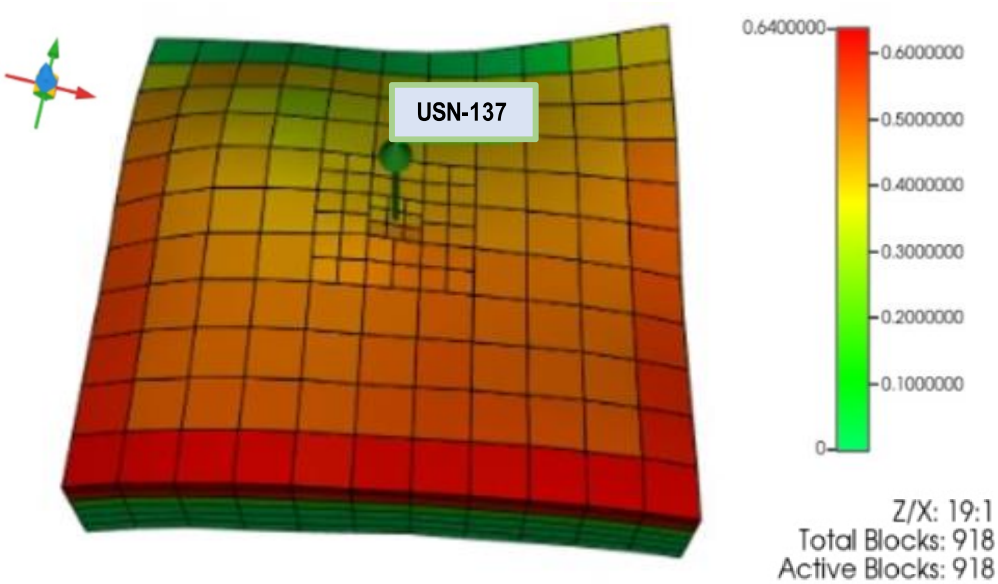

Figure 2.
Reservoir model.

Table 2.
USN-137 well data.

Parameters	Value and Units
Reservoir type	Carbonate
Reservoir pressure, Pr	750 psi
Reservoir temperature, Tr	91 ^{0}C
Porosity, %	16 - 23 %
Permeability, k	15 - 114 mD
Thickness, h	6 ft
Oil gravity	34.3 ^{o}API
Oil viscosity, µ	2.24 cp
Oil rate, Qo (Feb. 2024)	25 bopd
Water rate, Qw (Feb. 2024)	175 bwpd
Gas rate, Qg (Feb. 2024)	20,321 cuft/d
Original oil in place (OOIP)	2.24 MMSTB
Cumulative oil (Feb 2024)	0.58 MMSTB
Recovery factor, RF	25.9 %
Remaining oil	1.66 MMSTB
Oil Saturation	52.7 % PV

Table 3.
Fluid component data.

Component	Hydrocarbon	Oil Pressure	Critical Temperature	Acentric Factor	Mole Weight
		(atm)	(^{0}K)		(g/gmole)
CO_2	No	7.2800E+01	3.0420E+02	2.2500E-01	4.4010E+01
N_2 - C_1	No	4.4910E+01	1.8784E+02	1.1530E-02	1.6470E+01
C_2 - C_3	Yes	4.4470E+01	3.4091E+02	1.2799E-01	3.7540E+01
C_4 - C_5	Yes	3.5140E+01	4.4043E+02	2.1601E-01	6.4490E+01
C_6 - C_7	Yes	3.1090E+01	5.4578E+02	2.5084E-01	9.5550E+01
C_8 - C_{10}	Yes	2.6900E+01	6.1319E+02	3.1013E-01	1.2519E+02
C_{11} - C_{14}	Yes	2.2380E+01	6.9529E+02	4.0595E-01	1.7228E+02
C_{15}^+	Yes	1.5730E+01	8.3035E+02	6.3929E-01	3.016E+02

The reservoir simulation requires preparation of the input data, including the reservoir rock characteristics, fluids, production metrics, pressure, and other relevant variables. Table 3 details each component's critical pressure, critical temperature, acentric factor, and molecular weight.

A specific rock characteristic is found at the site, known as Rock Type 1. Rock Type 1 exhibits particular oil-water permeability (K_{ro}-K_{rw}) and gas-oil permeability (K_{rg}-K_{ro}) curves, as shown in Figure 3. Accordingly, the reservoir rock is classified as a water-wet type, where the cross-section is located between the K_{ro}-K_{rw} curve at S_w = 0.62. Although carbonate reservoirs generally have oil-wet or mixed-wet tendencies due to long-term interactions with polar components of oil (such as resins and asphaltene) and the complexity of their porous structures, in reality, the wettability of carbonates greatly varies depending on the specific conditions of the reservoir and its production history. In some instances, such as the history matching results shown in Figure 4 through Figure 6, carbonate rocks can be water-wet owing to the strong influence of the mineral composition, geochemical conditions of high salinity formation water, and the absence of significant contamination by polar components of light oil. Therefore, carbonate reservoirs can exhibit water-wet properties under exceptional conditions, as illustrated by the relative permeability (K_{ro}-K_{rw}).

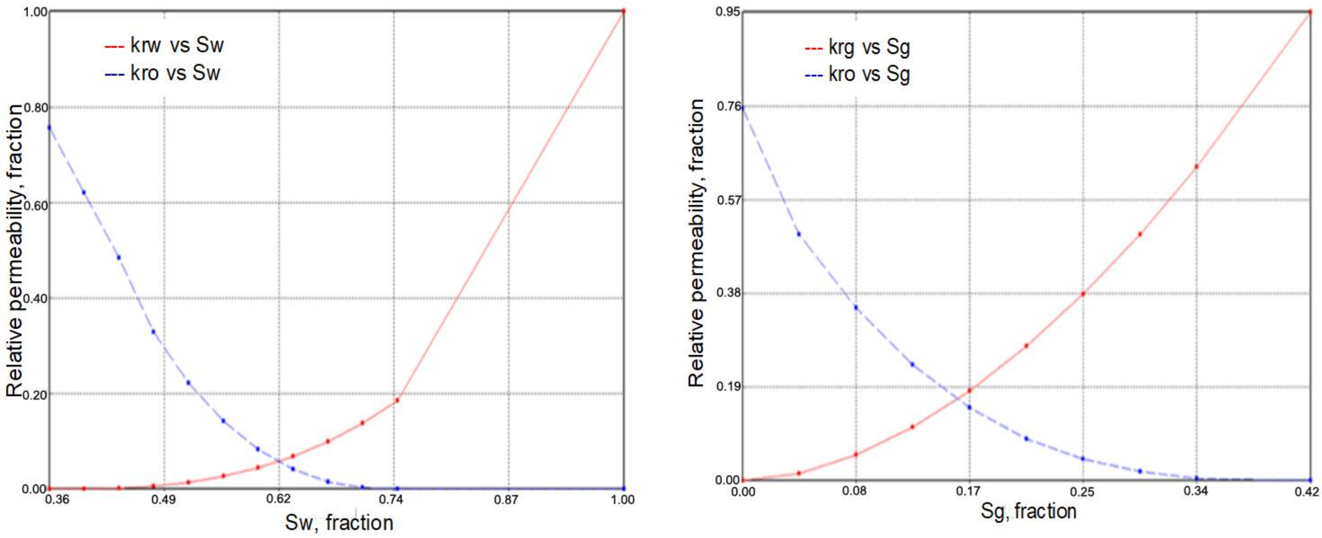

Figure 3.
Kro-Krw vs Sw (a) and Krg-Kro vs Sg (b) curves.

The initialization process involves determining the parameters and variables that constitute the simulation setup, aiming to ensure that the model accurately represents the reservoir conditions at the onset of CO_2 injection or a specific stage during the injection process. Upon completion of the initialization 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. Should a discrepancy arise between the model and the field data, additional modifications to the initialization parameters must be implemented. The OOIP initialization results are shown in Table 4. The initialization is performed until the OOIP value from the simulation has a maximum error of 5% compared with the volumetric case.

Table 4.
Initialization results.

Parameters	OOIP (MMSTB)
Volumetric	2.240
Simulation	2.236
% Error	0.21%

The differences between the simulation outcomes and the empirical data are minimized by optimizing the relevant model parameters. In the history matching step, adjusted parameters include the reservoir pressure, relative permeability curves, and aquifer modeling. Then, the model is validated using new or more comprehensive datasets to ensure accurate projections of future reservoir behavior, thus facilitating the planning of the injection volume. Based on the history matching results of the liquid, oil, and water rates shown in Table 5 and Figures 4 to 6, the difference between the actual data and the simulated data was less than 1%.

Table 5.
Summary of the history matching results.

Parameters	Actual (Mbbl)	Simulation (Mbbl)	Difference (%)
Liquid rate	1.3077	1.3037	0.30
Oil rate	0.3263	0.3251	0.37
Water rate	0.9814	0.9786	0.28

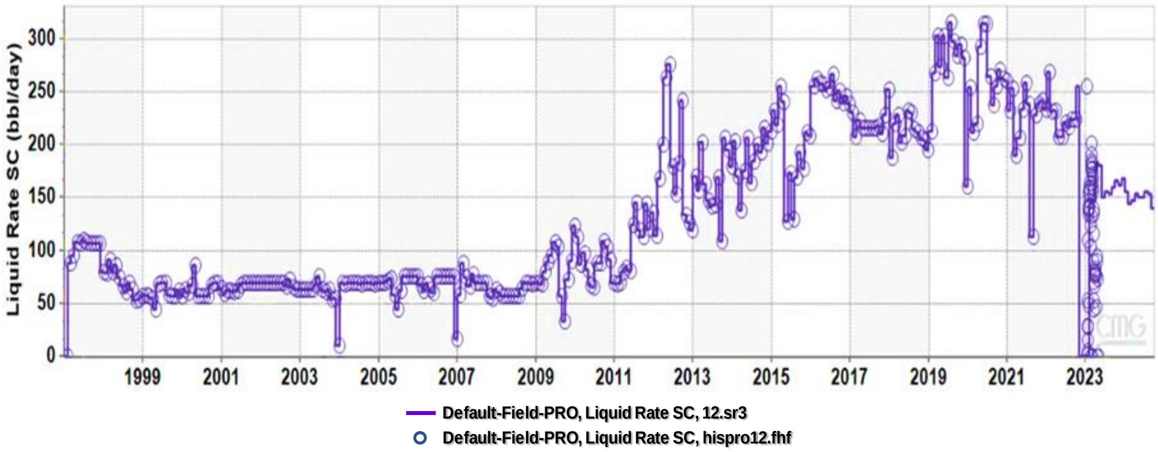

Figure 4.
History matching result of the liquid rate.

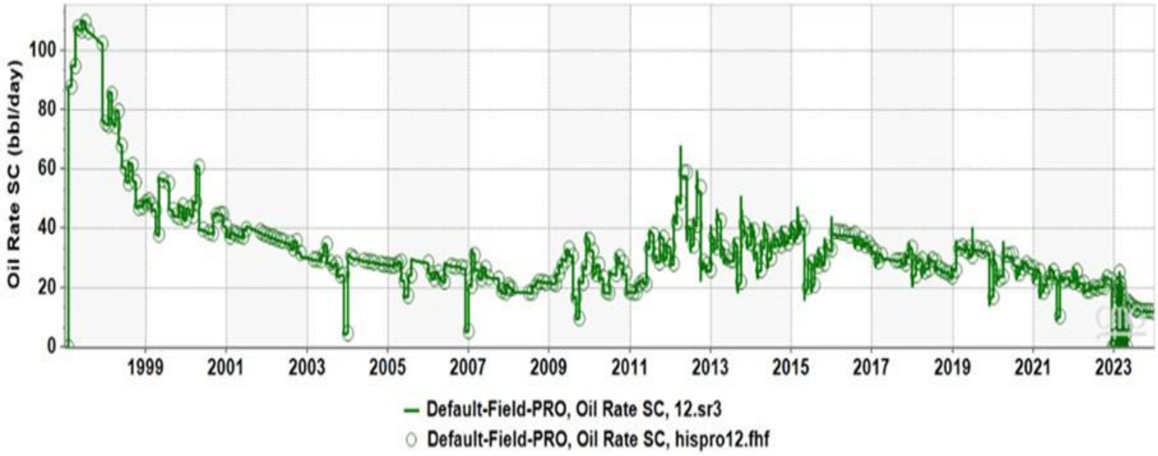

Figure 5.
History matching result of the oil rate.

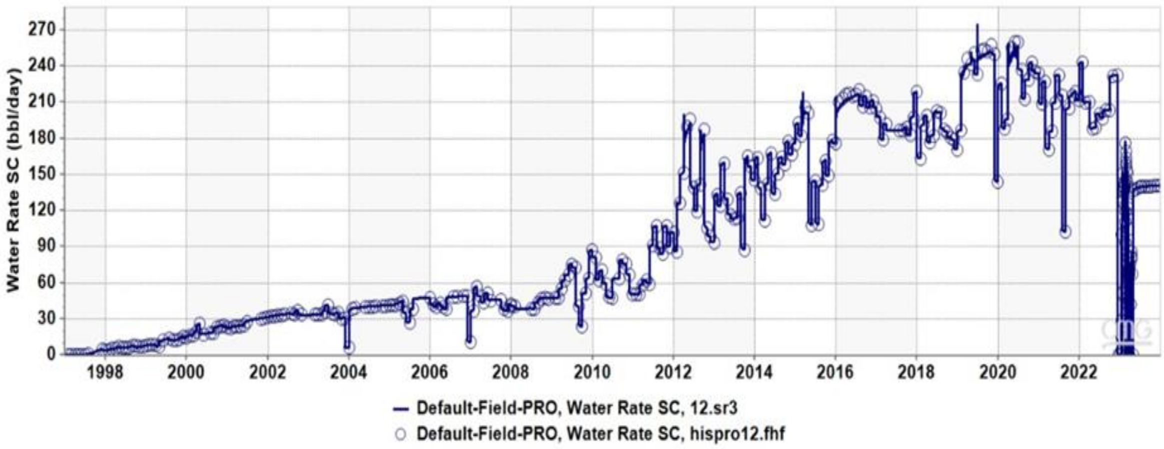

Figure 6.
History matching result of the water rate.

3.2. Injection Pressure Optimization

Injection pressure indicates the maximum allowable reservoir pressure during the injection process. Elevating the treatment pressure enhances CO_2 solubility and decreases oil viscosity. Multiple field tests have utilized injection pressures reaching 0.7 psi.ft depth, yielding favorable outcomes. Furthermore, increasing the rate of CO_2 injection into the well enhances CO_2 absorption within the reservoir, thereby improving contact with additional oil [29]. Injection pressure optimization is critical for maximizing 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, excessive energy consumption, or the potential leakage of CO_2 to the surface. Nevertheless, insufficient pressure diminishes the effectiveness, resulting in less effective CO_2 mobilization inside the reservoir.

Figure 7 shows the simulated cumulative oil production versus time for various injection pressure scenarios, namely 500 (baseline), 1000, 1500, 2000, 2500, and 3000 psi. The injection pressure has a significant impact on the oil production rate, where higher pressures, such as 2000 and 2500 psi, yield greater production rates than lower pressures, such as 500 and 1000 psi.

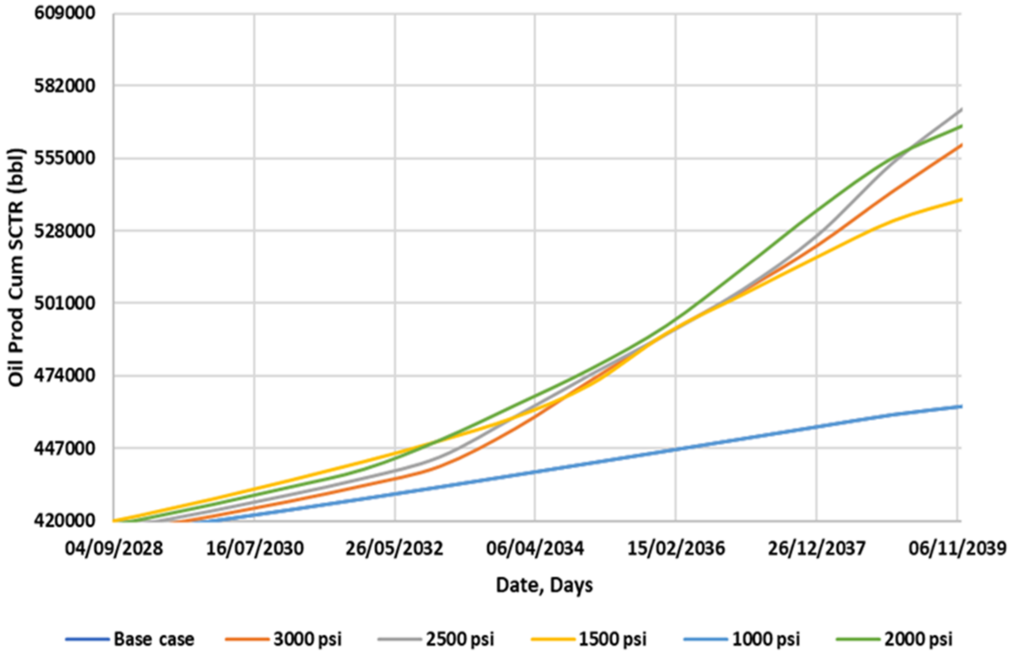

Figure 7.
Cumulative oil production for various injection pressures.

Figure 8 shows the correlation between RF, expressed as a percentage, and the injection pressure, measured in psi. At injection pressures below 1000 psi, the RF value remains relatively stable at approximately 20.65%. The injection pressure at that level does not significantly influence oil recovery enhancement. Beginning at an injection pressure of 1500 psi, a notable increase in RF occurs, rising from 20.65% to 24.11%. This increase signifies that the pressure is adequate to surpass the reservoir pore pressure, consequently enhancing oil mobilization. High pressure significantly enhances oil mobility through viscosity reduction, leading to peak production. The displacement observed in this case is classified as miscible displacement. However, elevated pressures may also heighten the potential for reservoir damage—medium pressures, such as 1500–2500 psi, provide a balance between production efficiency and long-term stability.

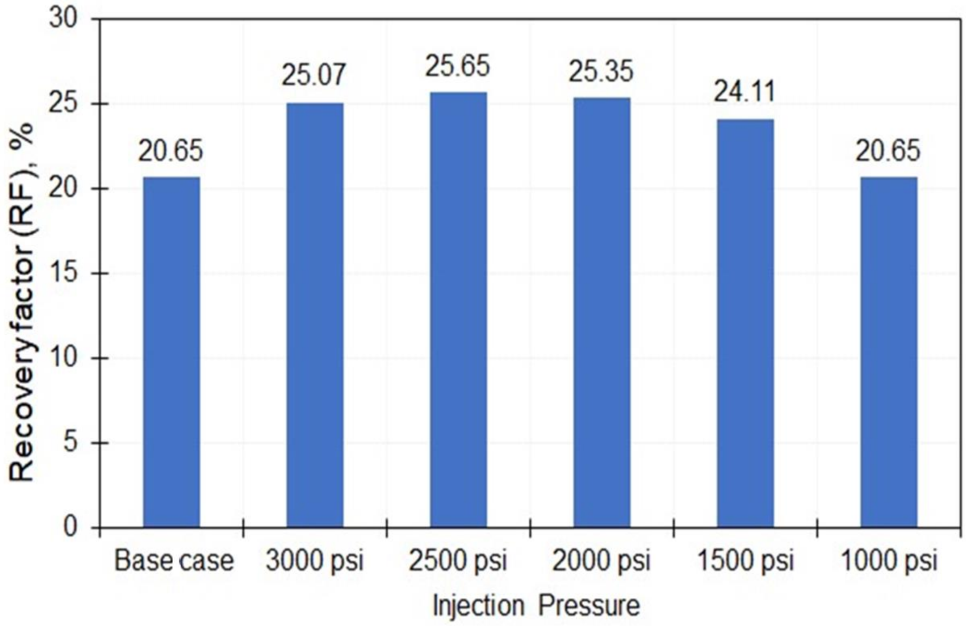

Figure 8.
Injection pressure optimization results.

Overall, based on the simulation results shown in Figure 7 and Figure 8, the highest cumulative oil production is obtained using an injection pressure of 2500 psi, and the lowest values are obtained at 500 (baseline) and 1000 psi. Hence, the cumulative oil production is directly proportional to the injection pressure; the greater the pressure applied, the greater the cumulative oil production and RF. A summary of the injection pressure sensitivity test results is shown in Table 6.

Table 6.
Summary of the injection pressure sensitivity test results.

Injection Pressure (psi)	Oil Production Cumulative (Mbbl)	Recovery Factor (Mbbl)	Incremental Recovery Factor (%)
500 (Base case)	462.7	20.65	-
3000	561.7	25.07	4.42
2500	575.8	25.65	5.00
2000	567.9	25.35	4.69
1500	540.2	24.11	3.46
1000	462.7	20.65	0.00

3.3. Injection Pattern Optimization

Injection-production well arrangements exhibit both regular and irregular patterns. The stability of the drilled well positions determine the consistency of the injection and production patterns, and the orientation of the primary permeability determines the positioning of the injection and production wells. Accordingly, CO_2 injection necessitates the establishment of an optimal well pattern [30]. Nonetheless, it is essential to comply with the principle that existing wells should be utilized to the greatest extent possible during subsequent injection activities. Areas with depleted pressure conditions are more conducive to using scattered peripherals, which exhibit higher sweep efficiency than patterned injection methods. Furthermore, the reservoir driving mechanism significantly influences the choice of injection-production well patterns, the volume of hydrocarbons, and the inclination of the rock layer to be displaced by gas. The layout of injection-production wells can be categorized into irregular pattern and regular pattern flooding's.

Figure 9 shows that the injection pattern plays an important role in oil recovery efficiency. The staggered line pattern shows the highest cumulative oil production at the end of the period. This pattern provides better pressure distribution and maximizes oil mobilization in the reservoir. The direct line and four-spot patterns give similar results to the triangular pattern but display slightly lower production. These patterns, including the five-spot pattern, likely exhibit lower production than the staggered drive pattern because the pressure is less evenly distributed in the reservoir. The line drive pattern shows the lowest cumulative production due to the limited range of the injection pressure.

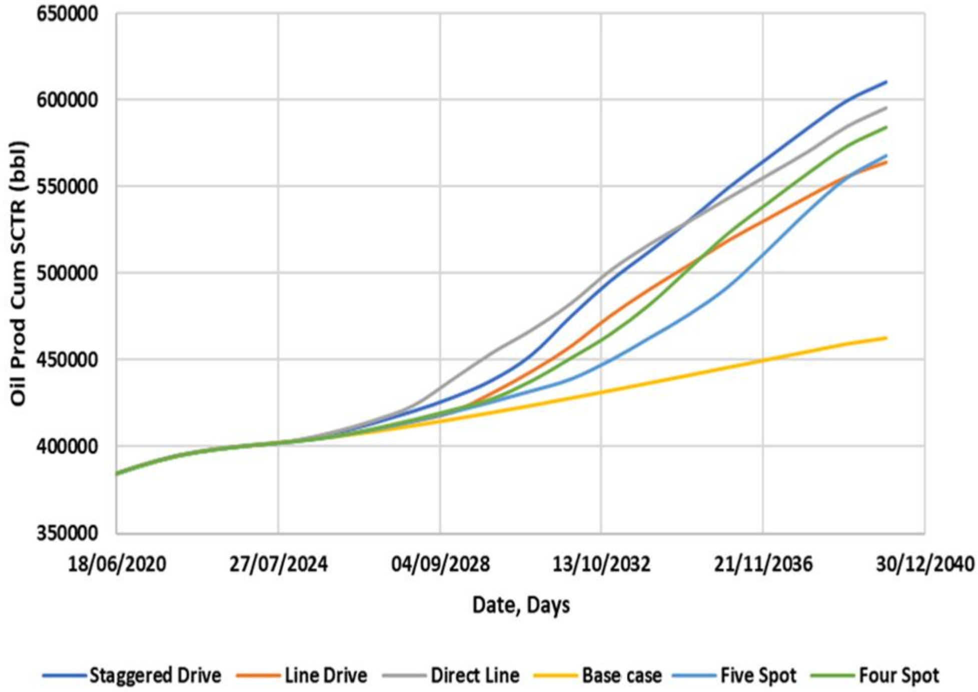

Figure 9.
Cumulative oil production for various injection patterns.

Figure 10 shows that the injection pattern substantially impacts the RF. The staggered drive pattern achieves a maximum RF of approximately 27.24%, demonstrating enhanced efficiency owing to the uniform pressure distribution and oil mobilization within the reservoir. The direct line pattern exhibits an RF of approximately 26.56%, accompanied by four instances with an RF of 26.08%. Although these results are promising, the direct line pattern does not outperform the staggered drive pattern. The line drive pattern yields a lower RF of approximately 25.16%, whereas the five-spot pattern results in an RF of 25.35%, highlighting its constraints in accessing the complete reservoir area.

Furthermore, proper selection of the injection pattern is essential to improve the recovery efficiency and maximize the oil production rate. From Figure 9 and Figure 10, the staggered drive pattern provides the optimal RF by enabling a more even pressure distribution, making it a better choice for total oil recovery efficiency. However, the direct line pattern is better at increasing the short-term oil production rate because of the greater injection pressure at any given time. The selection of the best pattern should be tailored to the operating objectives, prioritizing either the short-term production or the total recovery efficiency. A summary of the injection pattern optimization result is shown in Table 7.

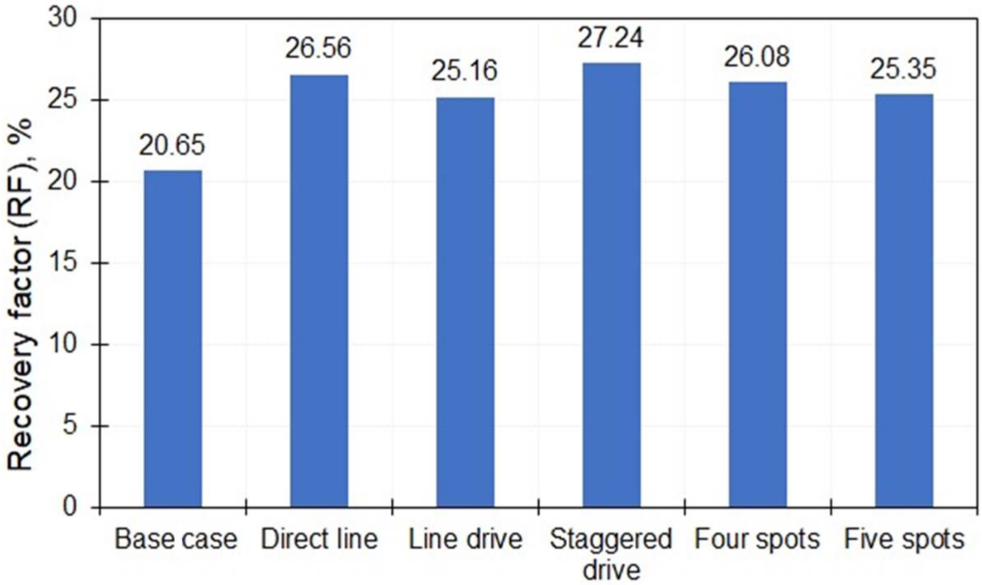

Figure 10.
Pattern optimization results.

Table 7.
Summary of the injection pattern optimization results.

Injection Pattern	Oil Production Cumulative (Mbbl)	Recovery Factor (Mbbl)	Incremental Recovery Factor (%)
Base case	462.73	20.65	-
Direct line	595.14	26.56	5.91
Line drive	563.77	25.16	4.51
Staggered drive	610.29	27.24	6.59
Four spots	584.37	26.08	5.43
Five spots	567.89	25.35	4.69

Figure 11 shows the changes in oil viscosity in the model during the simulation, indicating that the staggered drive pattern yields the highest oil production. This outcome is attributed to a significant reduction in oil viscosity, which enhances oil mobility within the reservoir. Meanwhile, Figure 12 shows that the staggered drive pattern effectively enhances oil displacement toward the production well, resulting in the highest RF value and providing the greatest cumulative oil production by the end of the period. Overall, this pattern enhances the pressure distribution and optimizes oil mobilization within the reservoir. The direct line and four-spot patterns yield results that approximate the triangle pattern, albeit at slightly lower levels, likely owing to the suboptimal pressure distribution compared with that of the staggered drive pattern. From the simulation results shown in Figure 11 and Figure 12 the staggered drive injection pattern yields the best results based on changes in the oil viscosity and oil saturation distribution after CO_2 injection.

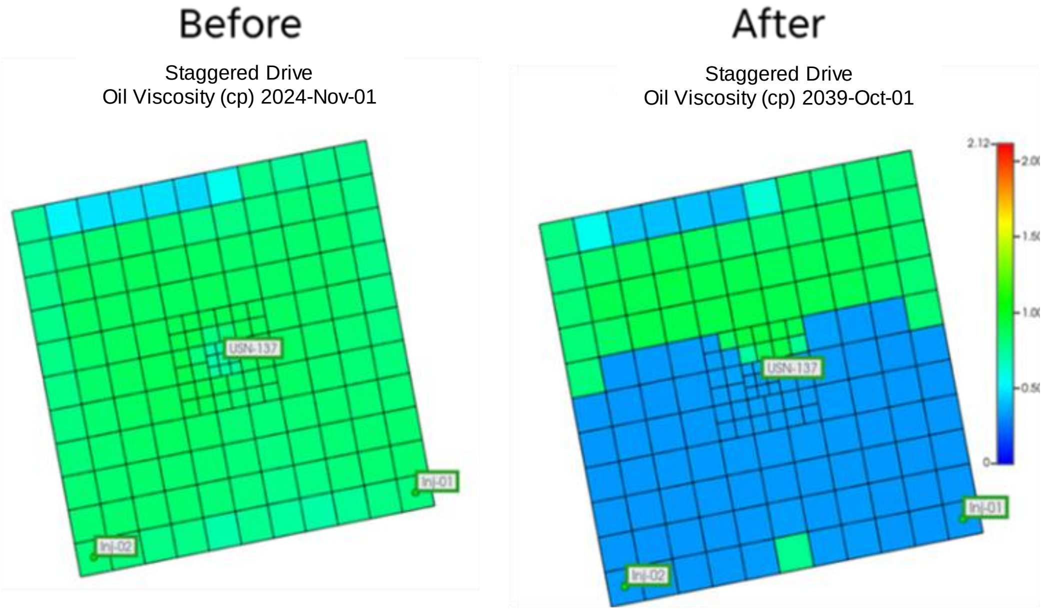

Figure 11.
Viscosity distribution changes for the staggered drive pattern.

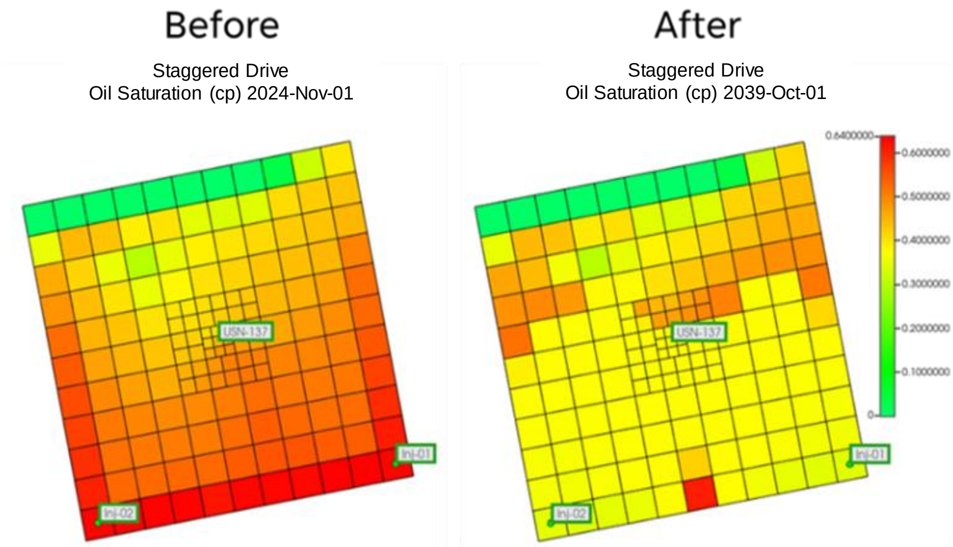

Figure 12.
Oil saturation distribution changes for the staggered drive pattern.

4. Conclusion

The implementation of CO_2 injection as a CCUS program to reduce hydrocarbon emissions and improve oil recovery in the Jatibarang oil field is demonstrated herein. The parameters used in the modeling CO_2 injection optimization include the reservoir rock type and fluid, heterogeneity of the carbonate reservoir, pressure and temperature, and the injection pattern. The CO_2 injection model is developed to determine the optimum injection pressure and injection pattern, as well as obtain the changes in oil viscosity and oil saturation distribution before and after CO_2 injection. As a result, a high injection pressure of 2500 psi is favorable, consistent with the concept that miscible displacement during CO_2 injection enhances RF efficiency. Additionally, the staggered drive pattern achieves the highest RF of approximately 27.24%, displaying an enhanced pressure distribution and increased oil mobilization within the reservoir. Optimization of the injection pressure and injection pattern parameters significantly enhances the RF efficiency in the advanced stage of the CO_2 injection scenario. Ultimately, the proposed methodology elucidates the optimal CO_2 injection scenario for the Jatibarang oil field and enhances the general understanding of its implementation on a broader scale.

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