Optimization of CO_2 Enhanced Oil Recovery Operating Conditions: A Case Study of El Morgan Oil Field Reservoir, Gulf of Suez, Egypt

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Abstract. Oil and gas are energy sources that experience the fastest growth among other energy sources. The oil recovery process can be divided into three recovery stages, namely primary oil recovery, secondary recovery and tertiary recovery or commonly called Enhanced oil recovery (EOR). Enhanced oil recovery (EOR) is an oil recovery used to recover residual oil that cannot be recovered by using waterflooding. According to the US Department of Energy, the tertiary recovery method has a successful recovery factor of up to 75%. EOR also helps reduce CO_2 emissions. However, to get optimal results for CO_2 EOR, several parameters must be optimized, such as mass flow rate, injection pressure and temperature. To create a pressure drop model for CO_2 EOR, several equations are used, including the Begg's-brill equation for the injection well dan production well model, the Darcy equation for the reservoir model. Based on the optimization results using Genetic algorithm and Particle swarm optimization, it was found that the profit increased by 97.4782% and 97.478%, respectively, with an increase from 994.2268 USD/days to 39425.92 USD/day for Genetic algorithm and 994.2268 USD/days to 39422.95 USD/day for Particle Swarm Optimization (PSO).

Keywords: Optimization · Enhanced Oil Recovery · Genetic Algorithm · Particle Swarm Optimization

1 Introduction

Oil and gas are energy sources that experienced the fastest growth in several countries among other energy sources with oil consumption increasing above the average of 1.4 million barrels per day (b/d) or 1.5% [1]. With the increasing demand for energy around the world and the depletion of energy sources, maximizing oil recovery from previously underutilized well reserves will be very important to meet the growing demand for energy [2]. According to the development stage, the oil recovery process can be divided into three recovery stages, namely primary oil recovery, secondary recovery and tertiary recovery. In primary recovery, oil is initially taken from the reservoir using the pressure in the

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reservoir itself. After the initial pressure from the reservoir is lost, oil can be recovered using pressure from outside the reservoir. In secondary recovery, the technique used is seawater injection into the reservoir or commonly referred to as waterflooding [3]. Primary and secondary oil recovery can achieve a total recovery efficiency of around 33% of Original Oil in Place (OOIP) or the original oil contained in the soil [4]. Enhanced oil recovery (EOR) is a technique that is included in tertiary recovery which is used to recover residual oil that cannot be recovered by using waterflooding. According to the US Department of Energy, the tertiary recovery method has a successful recovery factor of up to 75%, the EOR process has two basic advantages, namely the effectiveness of oil recovery with higher yields and lower costs [5]. EOR increase oil production from a reservoir or oil well that has experienced a decline in production which is carried out by injecting an energy or mass through an injection well into the oil reservoir. CO_2 EOR has been proven to be technically and economically successful for more than 20 years [6]. EOR with CO_2 injection also helps reduce CO_2 emissions, emissions from CO_2 contribute to global warming climate change. Many of the negative impacts caused by CO_2 emissions such as having profound effects on human health through diseases ranging from respiratory problems to lung cancer [7].

In this study, optimization of the operating conditions of CO_2 Enhanced Oil Recovery in the El Morgan oil field reservoir Gulf Of Suez, Egypt was carried out by considering costs, in this oil field using CO_2 as injection because it has a medium oil content with API Gravity of 29.9. The optimized variables include flow rate, temperature and pressure of CO_2 which is injected into the oil field reservoir through injection wells. This research will be conducted to optimize the yield of oil production in EOR using the CO_2 injection method. The algorithm applied in this research is the General Algorithm (GA) Particle Swarm Optimization (PSO) algorithm.

2 Methodology

The process carried out in this study begins with problem identification about how to get the maximum oil production possible to get the maximum profit. However, the costs incurred for the needs of this injection process such as the cost of procuring CO_2, the cost of CO_2 recovery and operational costs during the injection will potentially reduce the revenue generated.

2.1 CO_2 EOR Input Parameters and Reservoir Characteristics

In this study, the modeling simulation requires data in the form of input parameters, CO_2 injection operating conditions for better oil recovery, oil composition, and reservoir characteristics. For the input parameters used in the simulation of pressure drop and temperature gradient modeling, data obtained based on field conditions from the El Morgan oil field, Gulf of Suez, Egypt are shown Table 1.

For reservoir characteristics data refers to field conditions at the El Morgan oil field reservoir, Gulf of Suez, Egypt. Rock and reservoir data are shown in Table 2.

Table 1. Input Parameter Injection Well

Parameter	Value	Symbol
Well Diameter	14.75	*inch*
Gravity	9.8	m/s^2
Gravity Factor	1	
Well Depth	8450	*ft*
Tubing Thickness	0.0089408	*m*
Tubing Roughness	0.0000254	*m*
Reservoir Temperature	154	*degF*
Environment Temperature	31	*degC*

Table 2. Reservoir Characteristics

Parameter	Value	Symbol
Reservoir Length	100	*m*
Rock Permeability	100	md
Rock Porosity	0.23	
Reservoir thickness	67.056	*m*
Reservoir pressure	2400	*psia*
Reservoir temperature	154	*degF*

2.2 Pressure Drop Model in Injection Well and Production Well

Beggs-Brill in 1973 performed an energy balance analysis, and assumed that there was no external force from or to the fluid flow to obtain the pressure gradient equation in multiphase vertical flow Pressure drop in multiphase flow can be determined by the following equation [8].

$$\frac{dp}{dz} = \left(\frac{\partial p}{\partial z}\right)_{friction} + \left(\frac{\partial p}{\partial z}\right)_{elevation} + \left(\frac{\partial p}{\partial z}\right)_{acceleration} \tag{1}$$

Friction loss occurs when steam flows through a pipeline or injection tubing so that the pressure changes according to the length of the pipe or the depth of the well. Friction loss is affected by fluid friction with the pipe [9]. According to the Beggs-Brill equation above, the pressure drop in multi-phase flow occurs because of friction, elevation differences and acceleration. In this study, the flow used in a vertical pipe with a slope angle (θ) is 90. So that the total pressure drop equation is obtained as follows:

$$\left(\frac{\partial p}{\partial z}\right)_{elevation} = \frac{f_{tp} \times G_m \times v_m}{2 \times g_c \times d} + \frac{g}{g_c}\left[\rho_L H_L + \rho_g (1 - H_L)\right] \times 1 \tag{2}$$

2.3 Pressure Drop Model in Reservoir

Darcy's law is used to model the pressure drop in the reservoir. Darcy's law states that the motion of fluids in porous media. Darcy experimented with the flow of water through layers of sand. He found that the velocity of the water in the sand layer is proportional to the pressure drop as follows [10].

$$v = k\frac{h_1 - h_2}{L} \tag{3}$$

where v is the velocity of the water, k is the permeability, h is the hydraulic height, and L is the length of the column. The speed of the water is equal to the water discharge divided by the cross-sectional area of the sand [10]

$$v = \frac{q}{A} \tag{4}$$

so to calculate the pressure drop in the reservoir, the following equation can be used:

$$\Delta P = \frac{q\mu L}{KA} \tag{5}$$

2.4 Temperature Gradient Model

In the injection well and production well model, CO_2 injection, heat transfer (Q) from CO_2 to tubing in the well occurs. The amount of heat lost per unit depth is a function of the tubing radius (rto), the temperature of the bolts outside the tubing (Th), the steam temperature (T), and the overall heat transfer coefficient (Uto). The heat transfer equation is assumed to be in a steady state, then it is expressed as in the following equation [11]

$$\frac{dQ}{dz} = 2\pi \times r_{to} \times U_{to}(T - T_h) \tag{6}$$

To calculate the value of heat transfer that occurs in the reservoir, CO_2 that has been injected through the injection well will flow into the reservoir with certain PVP properties. Modeling heat transfer from CO_2 to the reservoir using the heat transfer equilibrium equation which is formulated as follows:

$$Q_1 = Q_2 + Q_{totallosses} \tag{7}$$

Energy values of Q_1 and Q_2 are obtained from the equation:

$$Q_1 = m_{co2} \times C_{p1} \times T_1 \tag{8}$$

$$Q_1 = m_{co2} \times C_{p2} \times T_2 \tag{9}$$

There is a certain amount of energy lost during CO_2 propagation from the injection well to the production well both by conduction and convection. The lost energy can be derived from the following equation:

$$Q_{totalloss} = \frac{T_1 - T_C}{R_{konduksi} + R_{konveksi}} \tag{10}$$

2.5 Calculation of Oil Production Volume and Profit

To obtain the estimated value of oil recovery, the coval method is used which explains that the flow fraction of CO_2 and recovered oil is influenced by the mobility ratio of CO2 + oil and the density difference between CO_2 and oil. For the results of the calculation of the rate of natural oil production, the income value can be obtained which is the multiplication between the rate of natural oil production and the price of natural oil and the calculation of daily oil production volume and profit can be done using the following equation:

$$N_p = \frac{\alpha + (F_i)_{BT}}{1 + \alpha} \tag{11}$$

$$(F_i)_{BT} = \sqrt{\frac{0.9}{(M + 1.1)}} \tag{12}$$

$$\alpha = \frac{1.6}{K^{0.61}} \times \left[\frac{(F_i)_{BT} - F_i}{1 - F_i}\right]^{\left(\frac{1.28}{K^{0.26}}\right)} \tag{13}$$

$$K = EHG \tag{14}$$

$$M = \frac{\mu_o}{\mu_s} \tag{15}$$

$$E = \left[0.78 + 0.22M^{1.4}\right]^4 \tag{16}$$

$$H = \left[\frac{V_{dp}}{\left(1 - V_{dp}\right)^{0.2}}\right]^{10} \tag{17}$$

$$G = 0.565 \times \log\left(\frac{t_h}{t_v}\right) + 0.87 \tag{18}$$

$$\frac{t_h}{t_v} = 2.571 \times K_v \times A \times \frac{\Delta\rho}{q_{gross} \times \mu_s} \tag{19}$$

After getting the fractional of displacement (Np), oil revenue can be calculated from the following equation:

$$oil\ recover = N_p \times OOIP \tag{20}$$

$$R_{oil} = oilrecover \times P_{oil} \tag{21}$$

To get the cost of procurement CO_2, it is obtained from the multiplication of the CO_2 volume and also the CO_2 price.

$$B_{co_2} = V_{CO_2} \times P_{CO_2} \tag{22}$$

In the application of CO_2 EOR, the oil produced in the production line still contains CO_2 gas, so a process for CO_2 recycle from the production fluid is needed. The calculation of the cost of CO_2 recycle is based on the following equation.

$$B_R = V_{prod} \times BR_{CO_2} \tag{23}$$

The operational cost of the CO_2 EOR pump is the cost of the electrical energy required for the pump to operate for a certain time. Calculation of pump operating costs using the results of modeling pressure drop injection well to production well in the previous stage, fluid mass flow rate, pump efficiency, pump electrical power requirements, pump operating time, and basic electricity tariff per kWh so that the pump operating costs can be obtained during process. The equation used in calculating pump operating costs is as follows.

$$W_p = \frac{q \times \Delta P}{\eta} \tag{24}$$

From the equation obtained above, it can be calculated for the maximum profit obtained by

$$P_{max} = R_{oil} - \left(B_{co2} + B_R + B_{Op}\right) \tag{25}$$

With:
P_{max} = Maximum Profit (USD/days)
R_{oil} = Oil Revenue (USD/days)
B_{CO2} = CO_2 Procurement Cost (USD/days)
B_R = CO_2 Recycle Cost (USD/days)
B_{Op} = Pump Operation Cost (USD/jam).

2.6 Optimization of CO_2 EOR Operating Condition

Optimization is carried out to obtain the most optimal CO_2 EOR operating conditions so that the objective function can be maximized. The optimization technique used is using the stochastic algorithm method in this problem because the objective function used here contains non-linear equations, even some variables are discontinuous, where if the optimization method used is a deterministic algorithm it will cause the possibility of the objective function results to be trapped in the optimal locale bigger. Based on this explanation, this optimization belongs to the Mixed Integer-Nonlinear Programming (MINLP) problem, so it is necessary to use a stochastic algorithm optimization technique that can present the objective function value which is the global optimum, because of its characteristics that test optimization variables randomly in each given range for get the most optimal results. With the algorithm used is Particle swarm optimization (PSO) and Genetic algorithm (GA) in MATLAB software.

Optimized variables are mass flow rate, temperature and pressure of CO_2 injection by maximizing profit. If it is convergent, then proceed to data analysis, the limit is determined by determining the upper bound and lower bound values. The upper bound value is the maximum value limit for the optimization variable, while the lower bound value is the minimum value limit for the optimization variable. Each algorithm has its own parameters. In Particle swarm optimization has population, iteration, elitism, crossover probability, mutation probability, number of bits. For the optimum criteria for EOR success is how to achieve maximum profit.

3 Result and Discussion

3.1 Result of Pressure Gradient and Temperature Gradient Model on Injection Well

Modeling the pressure drop and temperature gradient in the injection well using the Beggs-Brill method. The input parameters used can be seen in Tables 1 and 2. The results of the pressure drop modeling can be seen in Fig. 1.

In the graph, it can be seen that the CO_2 pressure increased along with the increasing elevation of the depth of the well when the CO_2 injection in the injection well took place, this happens due to the influence of gravity which causes an increase in hydrostatic pressure as the depth of the injection well increases.

The results of the temperature gradient modeling can be seen in Fig. 2. In the results of the temperature gradient graph it can be seen that the temperature in the injection well has increased along with the deeper the process when CO_2 injection takes place, this can happen because the CO_2 temperature factor is getting lower than the rock temperature in the surroundings, where the temperature increases with increasing distance from the surface.

The model of pressure drop and temperature gradient in the injection well using the Beggs-Brill method has been validated using PIPESIM software. In this modeling is carried out with an accuracy of every 50 m at the depth of the well and tested by modifying changes in mass flow rate, changes in pressure, and changes in temperature. The average error for pressure drop = 0.9475% and the average error for temperature gradient = 0.82%.

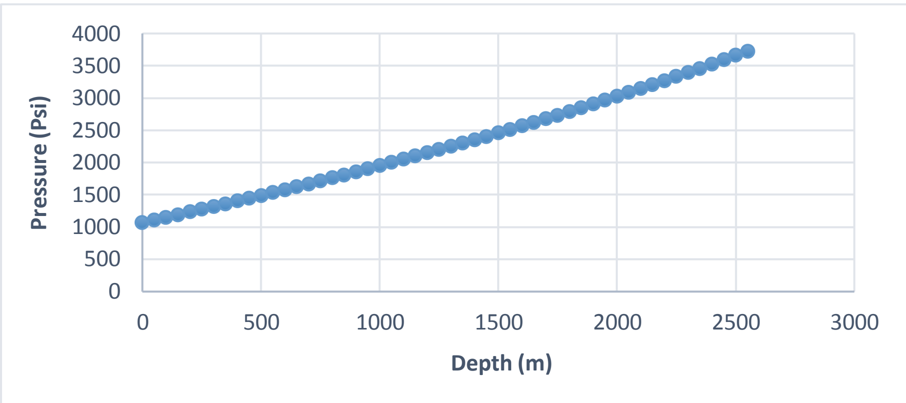

Fig. 1. Graph Pressure Drop on Injection Well.

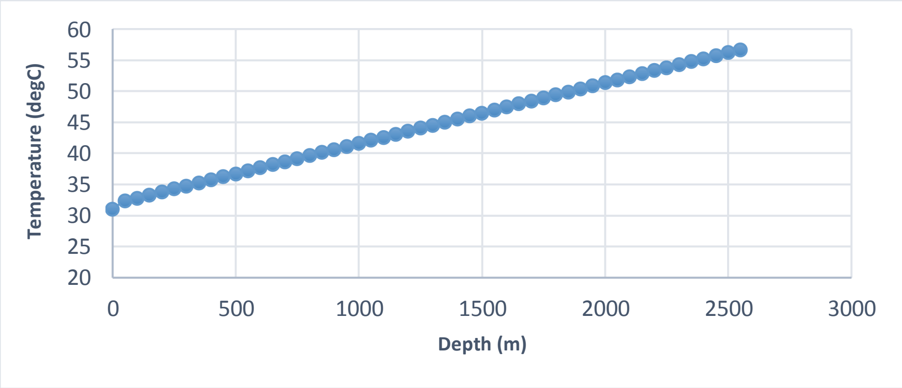

Fig. 2. Graph Temperature Gradient on Injection Well

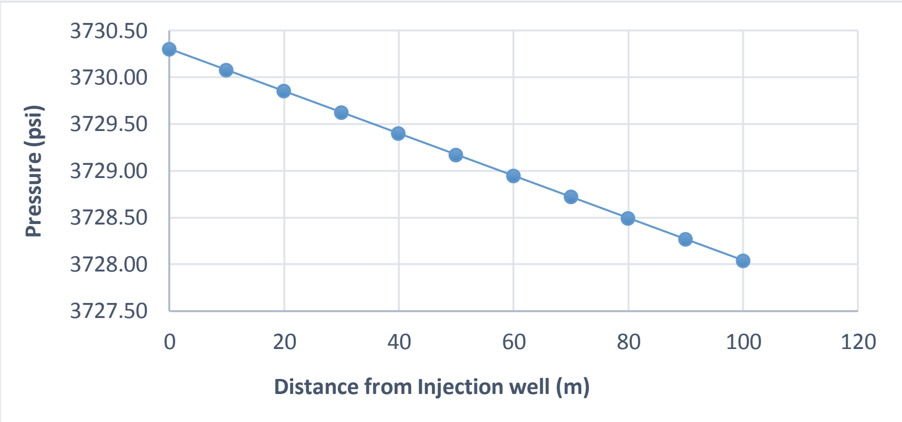

Fig. 3. Graph Pressure Drop on Reservoir

3.2 Result of Pressure Gradient and Temperature Gradient Model on Reservoir

The reservoir pressure drop model in the reservoir is modeled using the Darcy equation. The reservoir characteristics for the Darcy equation used as input parameters can be seen in Table 2. For the input pressure and temperature in the reservoir, the output pressure and temperature gradient from the injection well are the results. The results of the pressure gradient modeling on the reservoir can be seen in Fig. 3.

The results of the temperature gradient modeling on the reservoir can be seen in Fig. 4. The temperature of the mixture of CO_2 and oil also decreased with increasing distance from the injection well to the production well.

In Modeling the pressure drops and temperature gradient in the reservoir is done by segmenting the distance from the injection well of 10 m. The results of the validation of error modeling for pressure drop and temperature gradient in the reservoir have been

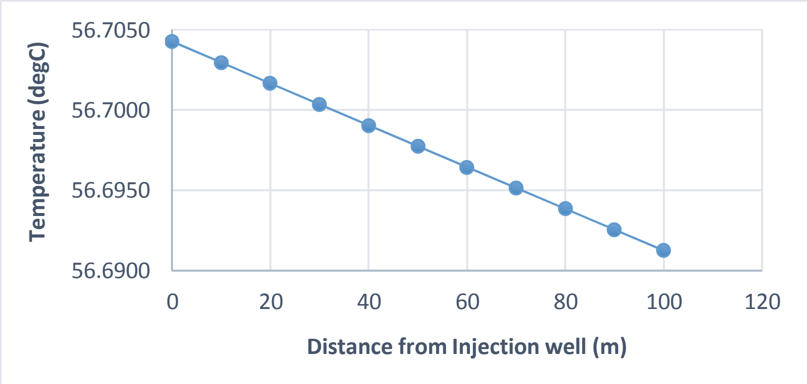

Fig. 4. Graph Temperature Gradient on Reservoir

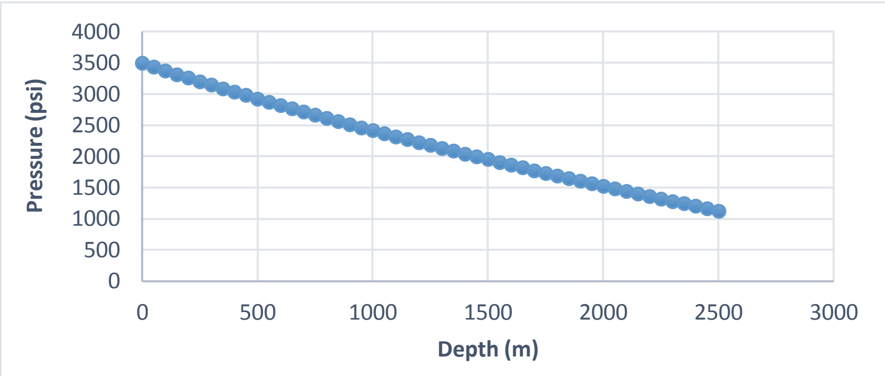

Fig. 5. Graph Pressure Drop on Production Well

obtained with the average error for pressure drop = 0.032% and the average error for temperature gradient = 0.516% for the simulation on COMSOL Multiphysics software.

3.3 Result of Pressure Gradient and Temperature Gradient Model on Production Well

The oil production process from the injection well and reservoir will be continued into the production well. The pressure and temperature characteristics from the pressure modeling with the Darcy equation on the reservoir will be used as input for modeling the production well (Fig. 5).

From the graph of the results of the pressure gradient modeling, it can be seen that in the production well section, it can be seen that the pressure and temperature of the production oil decreased as the oil approached the surface. The decrease in pressure is caused by reduced compression due to opposing the force of gravity. Another thing that affects changes in pressure is the friction between the CO_2 and oil mixture between the tubing walls of the production well.

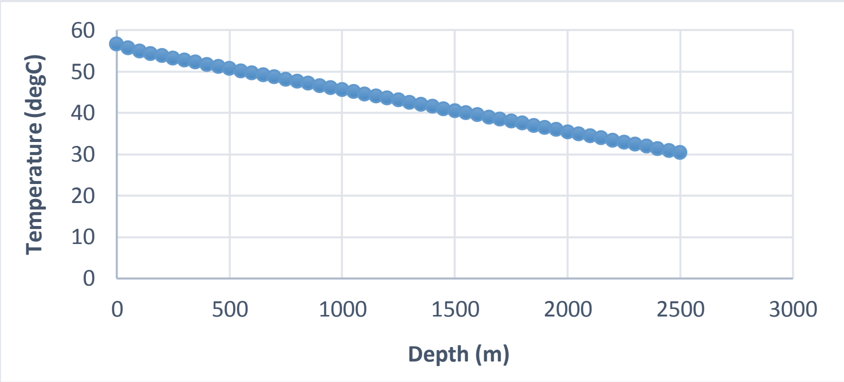

Fig. 6. Graph Temperature Gradient on Production Well

The results of the temperature gradient modeling on the production well can be seen in Fig. 6. The temperature of the mixture of CO_2 and oil decreased with increasing distance from the reservoir to the surface. The decrease in temperature of the mixture of CO_2 and oil slowly as it approaches the earth's surface is caused by the hardness of the rock formations around the tubing production well. In addition, a decrease in pressure and temperature can occur due to a change in the fluid phase of the mixture between oil and CO_2.

3.4 Result of Crude Oil Production and Profit Before Optimization

The stage after CO_2 injection starting from the injection well to the production well is to calculate the oil recovery or the amount of oil production produced from the El Morgan oil field, Gulf of Suez, Egypt. Oil recovery can be calculated from the comparison of the viscosity value between oil and CO_2 and the amount of oil contained in the reservoir or original oil in place. With input conditions of 1071 psi, temperature of 31 oC, mass flow rate of 0.3044 kg/s and OOIP of 2.7 million bbl, using Eq. 11–19 it can be calculated the oil production rate of 40,107 barrels per day, with recoverable oil of 89.37%.

After getting the rate of oil production from the previous calculation of 40,107 barrels per day and the selling price of crude oil is known to be 50 USD/bbl, using Eq. 20–25 it can be calculated oil income to profit. Assuming the amount of CO_2 carried into the production line is equal to the amount of CO_2, the calculation of the total profit from CO_2 EOR operations with operating conditions in accordance with Table 2 can be seen in Table 3.

Table 3. Profit Cost Before Optimization

Parameter	Value	Symbol
Crude oil cost	2005.3818	USD/day
CO_2 Procurement cost	408.7886	USD/day
CO_2 Recycle cost	601.6145	USD/day
Operating cost	0.7517	USD/day
Profit	994.2268	USD/day

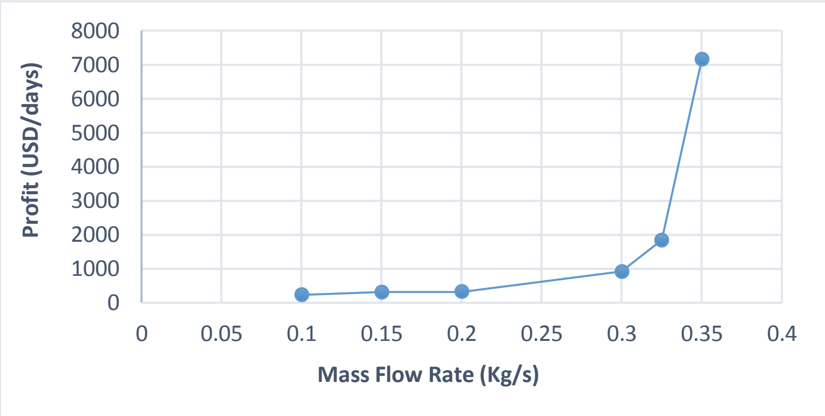

Fig. 7. Graph of sensitivity analysis of changes in CO_2 injection mass flow rate to total profit

4 Sensitivity Analysis

Sensitivity analysis was conducted to determine the effect of changes in one of the optimized variables on the estimated net profit to be obtained as an objective function that will be optimized in this study.

Figure 7 shows a graph of the sensitivity analysis of changes in the injection mass flow rate to profit. In this test, the pressure and temperature are constant. The curve shows the increase in profit along with the increase in the value of the injection mass flow rate.

The graph of the sensitivity of the injection pressure to profit is shown in Fig. 8 with a constant temperature and mass flow rate. In the graph it can be seen that the higher the pressure applied during the injection, the lower the profit obtained.

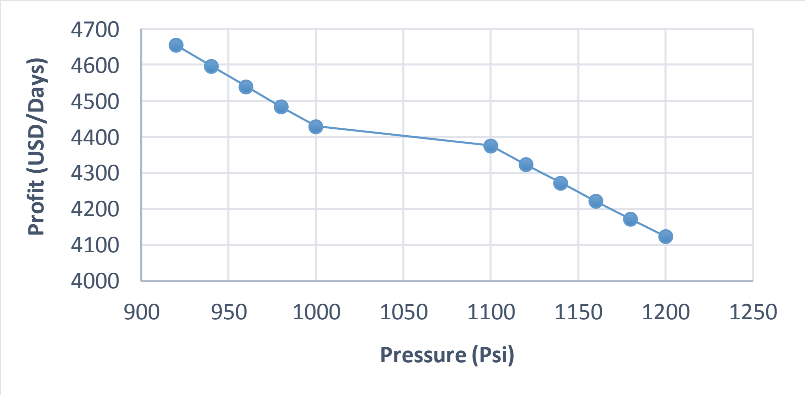

Fig. 8. Graph of sensitivity analysis of CO_2 injection pressure changes to total profit

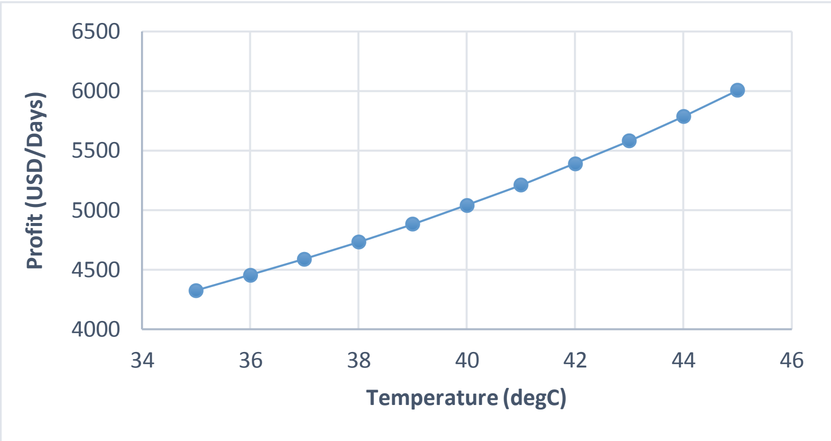

Fig. 9. Graph of sensitivity analysis of CO_2 injection temperature changes to total profit

In Fig. 9, it can be seen that the curve between the injection temperature and the profit shows an increase. The higher the temperature, the higher the profit obtained.

The graphs above show that the higher the mass flow rate and temperature will increase the profit from EOR. If the mass flow rate is higher, then a higher injection pressure is required. Meanwhile, the higher the pressure applied during the injection, the lower the profit value obtained. However, to get a high injection mass flow rate also requires a high injection pressure on the compressor. This is because the driving force of the mass flow rate is the injection pressure. So it is necessary to optimize the injection mass flow rate, injection pressure and injection temperature variables to get the optimum value of the objective function (net profit).

Table 4. Optimization Variable Genetic Algorithm

Optimization Variable	Before Optimization	After Optimization
Pressure Injection	1071 psia	999.99 psia
Temperature Injection	31 °C	65
Mass Flow Rate	0.3044 kg/s	0.6 kg/s

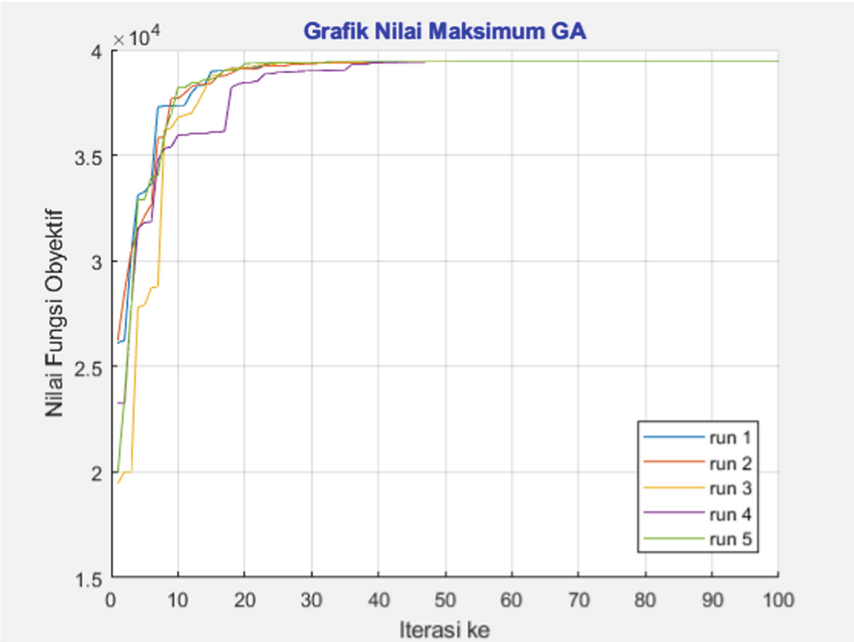

Fig. 10. Graph Genetic Algorithm fitness fitness plot

5 Optimization Using Genetic Algorithm

Optimization was carried out to find the optimal value of the optimization variables of the EOR process, namely injection pressure, injection temperature, and CO_2 injection mass flow rate. The objective function of this optimization is net income, which is the sum of revenue from sales of crude oil, deducted by CO_2 procurement costs, CO_2 processing costs and compressor operating costs. Table 4 shows the most optimal variables for optimizing CO_2 EOR.

CO_2 EOR using Genetic Algorithm can be seen in Fig. 10.

Table 5. CO_2 operation revenue after optimization with Genetic Algorithm

Parameter	Before Optimization (USD/days)	After Optimization (USD/days)
Crude oil cost	2005.3818	58687.6608
CO_2 Procurement cost	408.7886	805.7595
CO_2 Recycle cost	601.6145	17606.298
Operating cost	0.7517	849.6744
Profit	994.2268	39425.92

Table 6. Optimization Variable Genetic Algorithm

Optimization Variable	Before Optimization	After Optimization
Pressure Injection	1071 psia	1000 psia
Temperature Injection	31 °C	65 °C
Mass Flow Rate	0.3044 kg/s	0.6 kg/s

The results of net profit after optimization using Genetic Algorithm can be seen in Table 5.

Table 5 shows that the profit after optimization has increased by 97.4782% from the initial CO_2 EOR profit of 994.2268 USD/day to 39425.92 USD/day.

6 Optimization Using Particle Swarm Optimization

Optimization was carried out to find the optimal value of the optimization variables of the EOR process, namely injection pressure, injection temperature, and CO_2 injection mass flow rate. The objective function of this optimization is net income, which is the sum of revenue from sales of crude oil, deducted by CO_2 procurement costs, CO_2 processing costs and compressor operating costs. Table 6 shows the most optimal variables for optimizing CO_2 EOR.

CO_2 EOR using Particle Swarm Optimization can be seen in Fig. 11.

The results of net profit after optimization using Particle Swarm Optimization can be seen in Table 7.

Table 7 shows that the profit after optimization has increased by 97.478% from the initial CO_2 EOR profit of 994.2268 USD/day to 39422.95 USD/day.

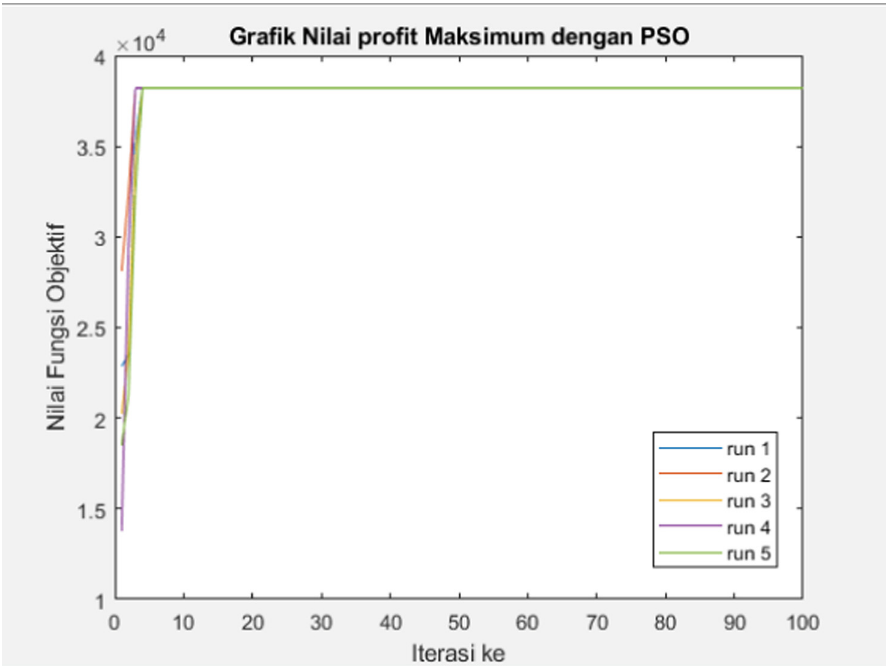

Fig. 11. Graph plot Global Best Particle Swarm Optimization

Table 7. CO_2 operation revenue after optimization with Particle Swarm Optimization

Parameter	Before Optimization (USD/days)	After Optimization (USD/days)
Crude oil cost	2005.3818	58683.3055
CO_2 Procurement cost	408.7886	805.7595
CO_2 Recycle cost	601.6145	17604.991
Operating cost	0.7517	849.6015
Profit	994.2268	39422.95

7 Conclusion

In injection well modeling, the validation results with PIPESIM showed Mean Absolute Percentage Error at pressure and temperature of 0.9475% and 0.82%, respectively. In reservoir modeling, the validation results with COMSOL Multiphysics show Mean Absolute Percentage Error at pressure and temperature of 0.032% and 0.516%, respectively. In the production well modeling, the validation results with PIPESIM show the Mean Absolute Percentage Error at pressure and temperature of 2.7104% and 0.7388%.

The optimization results in the case study of El Morgan oil field, Gulf of Suez, Egypt were carried out using Genetic algorithm and Particle swarm optimization, it was found that the economic impact could optimize the required costs such as the cost of procuring CO_2 increased by 49%, the cost of separating CO_2 increased by 97%, and pump operating costs increased by 100% for the process of increasing petroleum production. However, the increase in revenues from oil production was 97% higher than the costs incurred. So, the CO_2 EOR profit is up to 97.4782% from 994.2268 USD/day to 39425.92 USD/day. While optimization using Particle swarm optimization can optimize the required costs such as the cost of procuring CO_2 increased by 49%, the cost of CO_2 separation increased by 97%, and pump operating costs increased by 100% for the increasing petroleum production process. However, the increase in revenues from oil production was 97% higher than the costs incurred. so, the CO_2 EOR profit is up to 97.478% from 994.2268 USD/day to 39422.95 USD/day.

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