



Effects of miscible CO₂ injection on production recovery

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Abstract

Carbon dioxide (CO₂) injection is implemented into the reservoir to further improve the oil production efficiency, by mixing with oil at reservoir condition, and becomes miscible. The miscibility affects the oil to become swelled and less viscous and thus easily flow through the reservoir. Most of the (CO₂) EOR projects has higher recovery factor in miscible condition. Therefore, this article aims to determine the effects of the miscible (CO₂) injection on production recovery in the Cornea Field. The Cornea Field is located in Browse Basin, Western Australia. It is a simple trap structure which is elongated and formed by unfaulted drape anticline over an eroded high basement. The importance of this research is that (CO₂) injection has not been implemented in the Cornea Field since it is a complex reservoir. However, research showed that there was a high potential production recovery in this field. Therefore, research needs to be conducted to determine the effectiveness of the (CO₂) injection on production recovery in this field. The model was validated, by comparing MMP obtained from the simulation model and correlation methods. The MMP of this reservoir is above 38 Bar. Sensitivity analysis on reservoir pressure, reservoir temperature and (CO₂) injection rate was investigated. Oil production increases with the increase in reservoir pressure and reservoir temperature. As the (CO₂) injection rate increases, oil production also increased. From the result, hence, this study should contribute to the knowledge gap in Cornea Field.

Keywords Miscible CO₂ injection · EOR · Cornea Field · Minimum miscibility pressure · Reservoir simulation

Abbreviations

BBL	Barrels
MSCF/DAY	Million Standard Cubic Feet Per Day
MHz	Million Hertz

Symbol

P	Pressure (Bar)
V	Volume
n	No of moles
R	Universal gas constant
T	Temperature
T_{cm}	Weight average pseudocritical temperature of mixture (°F)
Z	Compressibility factor
X_{vol}	Mole fr of volatile (C1 and N2) oil components

X_{int}	Mole fr of volatile (CO ₂ and C2–C6) oil components
M_{C_5} or $M_{C_{7+}}$	Mol wt of oil pentane and heavier fraction (lb/lbmol)

Introduction

Carbon dioxide (CO₂) injection is one of the promising enhanced oil recovery (EOR) methods that have been applied in the oil and gas industry for many years. The CO₂ injection (Hoteit et al. 2019) into the reservoir to further improve the oil production efficiency is usually implemented after primary production of 10% to 20% of original oil in place and secondary production of addition 10% to 20%. Usually, CO₂ acts as a solvent, injected into the reservoir to increase the residual oil production. Carbon di oxide is injected into the reservoir because it can mix with oil at reservoir condition and become miscible (Fig. 1 shows a typical miscible of CO₂ flooding). The miscibility affects the oil to become swelled and less viscous and thus easily flow

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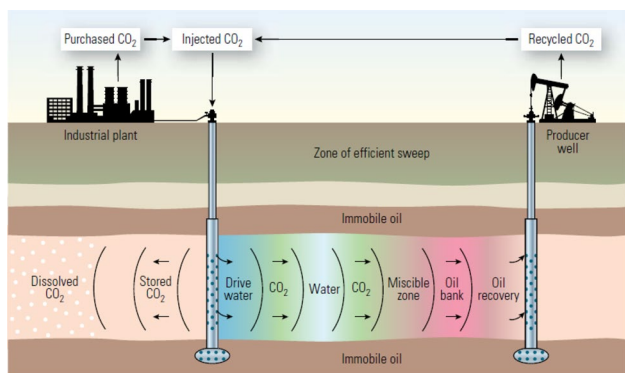


Fig. 1 Miscible CO₂ flooding (Aroher and Archer 2010)

through the reservoir. Most of the CO₂ EOR projects involve miscibility condition. Despite that, immiscibility condition may also be used to extract oil from reservoir (Cooney et al. 2018; Steinsbo et al. 2014; Tadesse 2018; Whittaker and Perkins 2013; Kalra et al. 2017).

However, not all reservoir is suitable for CO₂ injection. The oil composition, depth, temperature and other reservoir characteristic must be considered during CO₂ injection (Cooney et al. 2018; Steinsbo et al. 2014; Tadesse 2018; Whittaker and Perkins 2013; Kalra et al. 2017). At constant temperature, the lowest pressure at which liquid becomes miscible is known as “minimum miscibility pressure” (MMP). This is an important concept that explains the miscible gas injection because at this point, the injected gas and initial oil in place become a single phase, and the flow of the fluids becomes efficient. Accurate estimation of MMP for CO₂ flooding can significantly improve the reservoir recovery (Al-netaifi 2008; Liu 2013; Rezaei et al. 2013). This mostly occurs at a depth greater than 2500 ft, and the oil should have greater than 22 degrees API gravity with less than 10cP viscosity. The saturation of the oil should be higher than 20% of the pore volume (Ansarizadeh et al. 2015; Aroher and Archer 2010; Meyer 2007). From the CO₂ injection, the amount of oil recovered worldwide has been estimated to be around 450 billion BBL (Ansarizadeh et al. 2015; Bergmo and Anthonsen 2014; Cook 2012; US Chambers 2021; Tian and Zhao 2008).

When CO₂ mixed with oil is produced (Fig. 1), it can be separated and can be reinjected into the reservoir as a storage, which can contribute significantly to the reduction in the emission of greenhouse effect (Kamali and Cinar 2013; McLaughlin 2016; Melzer 2012; Parker et al. 2009; Qi et al. 2008; Safi et al. 2015).

As mentioned by Whittaker and Perkins (2013), miscible CO₂ injection was commonly used in oil extraction due to its effectiveness in increasing oil recovery. Therefore, this study aims to evaluate the effect of miscible CO₂ injection on the production of the Cornea Field (Fig. 2). The Cornea Field

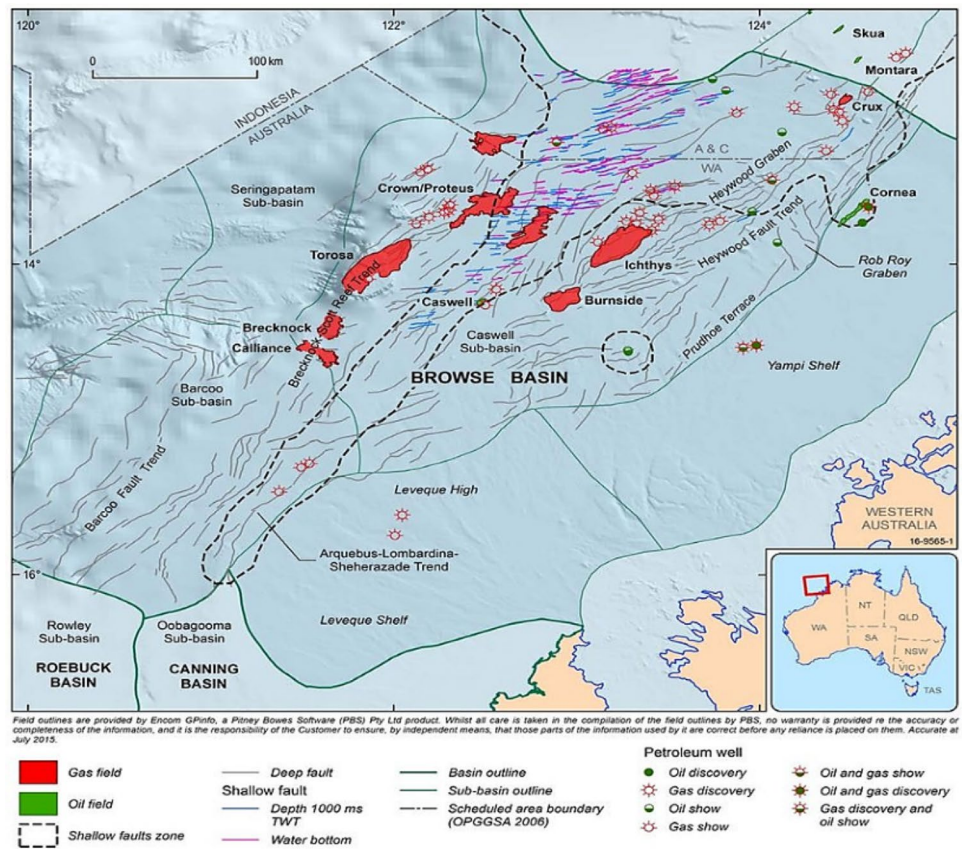
is located in Browse Basin, Western Australia. It is a simple trap structure that is elongated and formed by unfaulted drape anticline over eroded high basement (Ingram et al. 2000). This study is done because there was no investigation done previously in the Cornea Field on the effectiveness of CO₂ injection to improve oil production. Figure 2 shows a structural perspective of Browse Basin.

Investigation on different cases of natural depletion of the reservoir in one of the Iranian oil fields had been done by Fath and Pournafard (2013). They have also conducted the immiscible and miscible CO₂ flooding to increase the oil production. To determine the minimum miscibility pressure, slim tube simulation was run at different pressures using model (Zene et al. 2019a, b; Mohyaldinn et al. 2019; Mohyaldin et al. 2019) with 600 grid (Zhalehrajabi et al. 2014; Naser et al. 2007) blocks. The MMP for injection of CO₂ was about 4630 psia. From the simulation (Khan et al. 2003, 2001), the result showed that the optimum injection rates were 17,000 Mscf/day and 30,000 Mscf/day. These are for immiscible and miscible CO₂ injection, respectively. At the end of 20 years of total oil production, the miscible CO₂ injection showed 36.6% of recovery factor, while the recovery factor for immiscible CO₂ injection was 34.5%. This showed that the miscible injection was more feasible. However, the miscible condition was tough to reach some point in the heavy oil reservoir. Therefore, immiscible condition was recommended for future study (Fath and Pournafard 2013; Karaei et al. 2015; Vark et al. 2004).

On the other hand, Zarei and Azdarpour (2017) investigated the effectiveness of CO₂ injection. Eclipse 300 was used to examine the CO₂ injection. The oil in the tank was analyzed by software PVTi and experiment contact volume expansion and phase release on the oil. The PVTi output was used for Eclipse 300 input. Six wells were extracted for 10 years with CO₂ injected for 50 years. The injection rate had a direct impact on the EOR. The miscibility condition was studied with an injection of 5000 Mscf/day, which was still under immiscibility condition and miscibility achieved at and injection of 9000 Mscf/day. There were different cases compared: miscible injection at different pressure, miscible and immiscible with different flow rate, water injection then CO₂ injection and vice versa. The result showed that the alternate miscible CO₂ injection and water was a good scenario for oil production (Zarei and Azdarpour 2017; Montazeri and Sadeghnejad 2017). This study was conducted with simulated PVT experiments to investigate the effects of the use of miscible and non-miscible CO₂ in the Safah oil field. The results show that miscible CO₂ injection—rich gases produce more oil than lean gases—leads to higher recovery (Hearn and Whitson 1995).

CO₂ injection for different miscibility condition was also investigated by Han et al. (2014). The study was performed in the 2D vertical sandstone with unstable gravity drainage

Fig. 2 Structural element of Browse Basin: Cornea Field on the upper right side of the map (black lines represent faults) [26,(Poidevin et al. 2015)]



condition. CO₂ was injected at the bottom with 100% oil saturation. The results show that these conditions are consistent with the results of the previous study on the effects of a single photon emission from a laser beam. The results showed that there is no significant difference in effect between the two types of laser beams. It was shown that the oil production increased when miscible condition reached (Han et al. 2014; Alsulaimani 2015; Bhatti et al. 2019; Binshan et al. 2012).

Verma (2015) researched the CO₂ EOR processes to estimate the recoverable oil in the USA. It was studied because CO₂ injection has been one of the methods that has been considered as a solution for the economic profitability. It was also studied that there were different tools that can be used to calculate the MMP (using slim tube tests), mathematical model (Saeid et al. 2018) and correlations. From the discussion, the mathematical model (Sern et al. 2012; Hamzah et al. 2012) provided best result in estimating the MMP, which used equilibrium data and equation of state, while slim tube was expensive and correlation was used only when there were no slim tube and mathematical correlation available even though it was easy to use. From the study, it was determined that the oil recovery increased when pressure increased until it reached MMP. To achieved optimum (Khan et al. 2012) recovery, miscible CO₂ (Rashid

et al. 2014a, b) EOR injection was chosen as a better condition than immiscible injection (Verma 2015; Abdalla et al. 2014; Olea 2017; Perera et al. 2016).

Rudyk et al. (2005) also aimed to examine the CO₂ EOR and to determine the recoverable oil in the North Sea chalk samples. It was studied that there were few parameters that affect the MMP such as chemical composition, reservoir temperature and physical dispersion. Therefore, these factors need to be considered during the investigation. An experiment was performed on cylindrical and cubicle core at high pressure and temperature. It was shown that the oil recovery increased until it reached 180 MMP and the highest oil volume extracted was at 2611 psi. It also determined that the CO₂ injection was applicable for the field with 29% of recovery (Rudyk et al. 2005; Akbari and Kasiri 2012; Jensen 2015; Tzimas et al. 2005).

The observation of the CO₂ injection into a sand pack was studied by Yuechao et al. (2011) using 400 MHz NMR micro-imaging system. For immiscible CO₂ displacement, it was shown that CO₂ fingering was occurred due to difference in oil and CO₂ viscosity and density. Therefore, there were 53% of residual oil left in the sand pack. For miscible CO₂ flooding, it showed that the sweep efficiency was high. But the viscosity and density of gas were low and the velocity were the same. The residual oil left in the sand pack was 34%,

which was lower than immiscible injection. Thus, this showed that the miscible injection can increase recoverable oil.

Contrarily, Al-Abri and Amin (2010) researched on the dependency between interracial tension and relative permeability and also the displacement efficiency of the CO₂ injection into gas condensate reservoir. A laboratory condition was set at high pressure and temperature condition to simulate the reservoir conditions and to conduct relative permeability measurement on sandstone cores at constant reservoir temperature of 95C and displacement velocity of 10 cm/h. Displacement investigation at the immiscible condition at 1100 and 1200 psi, near miscible at 3000 psi and miscible at 4500 and 5900 psi was also included. The core flooding results showed that the pressure was the main factor that controlled the sweep efficiency. Miscible flooding showed optimum recovery of 32% with a better mobility ratio and delayed gas breakthrough, while near miscible was only recovered 23%. For the interfacial tension in the miscible displacement, the fluid properties and phase behavior relationships between CO₂ and condensate were stated to be the driving force that increased the recovery by stabilizing the displacement front.

Farzad (2004) also examined the effects of the injection pressure, vertical/horizontal permeability ratio and relative permeability on the recovery in miscible and immiscible displacement. A 3D, three-phase, Peng–Robinson equation of state compositional simulator method was used to determine the effectiveness of the parameters on the miscible and immiscible displacement. With an estimation of MMP, miscible injection was proven to increase the oil recovery with injection pressure between 5000 psi and 5600 psi where MMP was at 5000 psi.

The research trend has been moved to assess the potential of the CO₂ dissolved concept (Castillo et al. 2017), which combines two different approaches to research into carbon dioxide and its impact on climate change. The aim there was to identify and quantify the thermo-hydrochemical processes triggered by the release of dissolved CO₂ from carbonated aquifers in the form of hydrochloric acid (HCA) and hydrofluoric acid into the atmosphere.

From the literature review, most of the studies showed that miscible CO₂ injection was the most efficient way for oil recovery. Therefore, the aim of this paper is to determine production recovery by miscible CO₂ injection into the reservoir. The objectives of this paper are:

- To implement CO₂ injection simulation to the Cornea Field (Abdullah et al. 2019; Ishak et al. 2018)
- To determine the minimum miscible pressure (MMP)
- To evaluate the effect of miscible CO₂ injection on oil production recovery in the Cornea Field for 20 years

Methodology

Data were primarily collected from Geoscience Australia and some from Occam Technology Company. The model was constructed using the PETREL software by importing data collected.

Pressure–volume–temperature analysis (PVTi) and ECLIPSE software were used in this research. PVTi as an equation of state-based code was used to characterize a set of reservoir fluid samples. This is important because the model needs to have a realistic physical model of the fluid sample before input it to the reservoir simulation. The output of the PVT data was then imported into ECLIPSE (Saoyleh 2016; Ying 2013). Table 1 shows the steps in generating PVT table. Equations 1 to 12 were implemented in the PVTi software to generate the result (Slumberger 2014).

• Equation of state for real fluid

The real gas model is given by Eq. (1)

$$PV = nRTZ \quad (1)$$

• Cubic equation

The cubic form of model can be written as follows Eq. (2)

$$Z^3 + E_2Z^2 + E_1Z + E_0 = 0 \quad (2)$$

Table 1 PVTi software procedure to obtain PVT table

Fluid properties estimation	Input of composition and weight fraction To fit the equation of state Constant composition expansion (CCE) and differential liberation (DL) plots generated
Equation of State	Peng Robinson EOS Use later to generate PVT table for ECLIPSE simulation
Flash calculation	Input pressure and temperature of the reservoir fluid To determine phase split and composition
Regression	DL experiments used in the regression To improve the fitting equation of states with experiment observation results to produced better representation of the fluid Sensitivity analysis done to see the smallest attribute changes

$$E_2 = (m_1 + m_2 - 1)B - 1 \tag{3}$$

$$E_1 = A - (2(m_1 + m_2) - 1)B^2 - (m_1 + m_2)B \tag{4}$$

$$E_0 = -(AB + m_1m_2B^2(B + 1)) \tag{5}$$

$$m_1 = 1 + \sqrt{2} \tag{6}$$

$$m_2 = 1 - \sqrt{2} \tag{7}$$

• **The intensive form of Peng Robinson EOS**

The PR EOS is given by Eq. (8)

$$P = \frac{RT}{V - b} - \frac{a(T)}{V^2 + 2bV - b^2} \tag{8}$$

where

$$a(T) = a_0 \left(1 + k_{pr} (1 - \sqrt{T_r}) \right)^2 \tag{9}$$

$$a_0 = 0.45724 \frac{R^2 T_c^2}{P_c} \tag{10}$$

$$b = 0.07780 \frac{RT_c}{P_c} \tag{11}$$

$$k_{pr} = 0.37464 + 1.54226\omega - 0.2699\omega^2 \tag{12}$$

The PVT data were imported into ECLIPSE and used to simulate the CO₂ injection. The CO₂ injection keyword WINJGAS was used to implement the gas injection we ll. MISCIBLE keyword was used for miscible CO₂ injection reservoir. The model was validated by comparing MMP obtained from the result with MMP correlation methods. Correlations were used because it was a more time saving and easier method despite its accuracy. The sensitivity analyses were done by varying different reservoir properties such as initial reservoir pressure, reservoir temperature and CO₂ injection rate. Below are the correlations used to calculate the MMP (Adekunle 2014; Khazam et al. 2016) as stated by Eqs. (13), (14) and (15):

• **Alston (1985)**

$$MMP_{CO_2(Pure)} = 0.000878T^{1.06}M_{C_{5+}}^{1.78} \left(\frac{X_{vol}}{X_{int}} \right)^{0.136} \tag{13}$$

Table 2 Component and weight fraction data inputted to PVTi software

Components	Weight fraction (%)	Molecular weight (g/mol)
CO ₂	1.42	44.01
N ₂	1.2	14.0
C ₁	20.03	16.04
C ₂	4.8	30.07
C ₃	6.5	44.1
C ₇₊	66.05	218

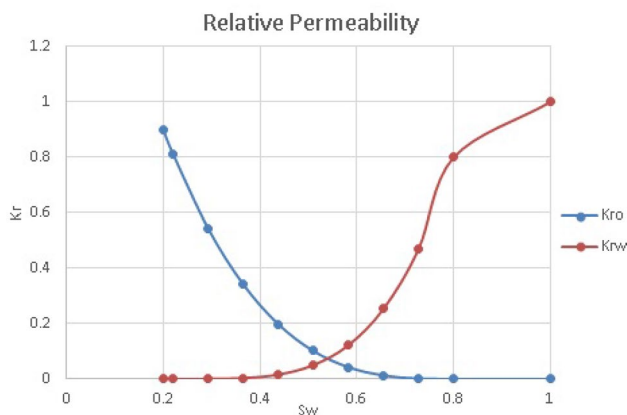


Fig. 3 Relative permeability of oil and water

$$MMP_{CO_2(impure)} = MMP_{CO_2(Pure)} F_{imp} \tag{14}$$

$$F_{imp} = \left(\frac{87.8}{T_{cm}} \right)^{1.935 \left(\frac{87.8}{T_{cm}} \right)} \tag{15}$$

• **Glaso (1980)**

Glaso proposed the model (Eq. 16)

$$MMP = 810 - 3.404M_{C_{7+}} + \left(1.7 \times 10^{-9} M_{C_{7+}}^{3.730} e^{786.8M_{C_{7+}} - 1.058} \right) T \tag{16}$$

Table 2 states the component and weight fraction data inputted to PVTi software.

Figure 3 shows the relative permeability of the oil and water.

Figure 4 shows the capillary pressure versus water saturation.

Results

Two wells were implemented in this reservoir model, which are injector and producer wells. This is to see the behavior of the injector and producer wells individually and to see how much it can be produced alone. Please refer to Fig. 5 for the

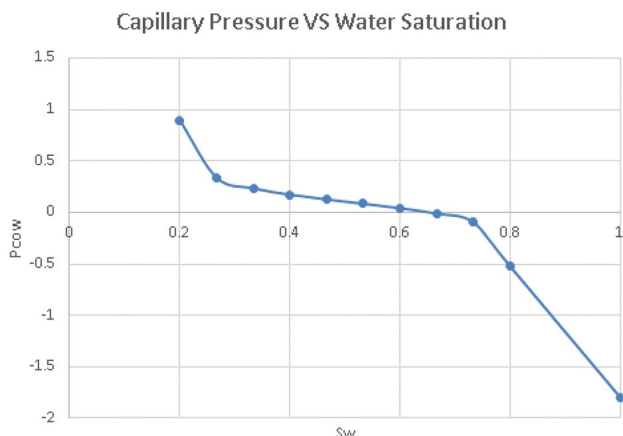


Fig. 4 Capillary pressure versus water saturation

reservoir model with injector and producer wells. Table 3 shows the model condition imported in PETREL. Table 1 shows component and weight fraction data inputted to PVTi software (Tables 4, 5).

After the model was validated, sensitivity analysis was performed to see how the variable changes effect the production recovery.

Effect of reservoir pressure

Reservoir pressure is very important, and this should be accounted in order to have an efficient oil recovery. Therefore, CO₂ was injected to improve reservoir pressure after primary and secondary production. Therefore, the reservoir pressure was investigated to see its effect on oil production with constant CO₂ injection rate. The reservoir pressure was tested from 30 to 50 Bar while maintaining other parameters constant. Figure 6 shows the oil production increased with an increase in reservoir pressure. This is because with CO₂ injection, it helps to improved oil recovery by reducing oil surface tension, swelling the oil, then lowering the oil viscosity and by moving the lighter oil components, hence increasing sweep efficiency. Figure 7 states the field oil production total decreased as pressure increased with time.

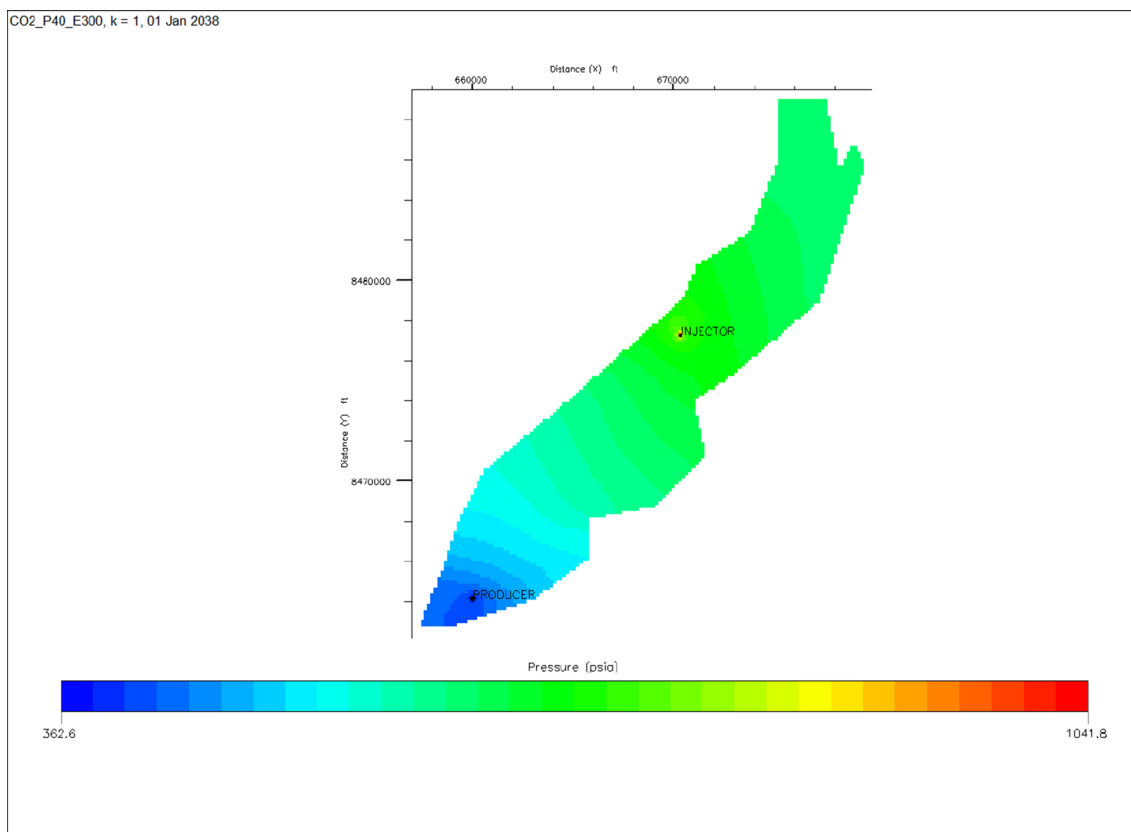


Fig. 5 Reservoir model with injection and producer wells: start producing at 40 Bar

Table 3 Reservoir condition

	Value
<i>Initial condition</i>	
Datum depth	– 80 m
Datum pressure	80 Bar
Gas-oil depth	– 771 m
Water contact depth	– 783.5 m
<i>Fluid condition</i>	
Minimum pressure	64 Bar
Maximum pressure	83 Bar
Reference pressure	80 Bar
Reservoir temperature	377.89 K

Table 4 Component and weight fraction data inputted to PVTi software

Components	Weight fraction (%)
CO ₂	1.42
N ₂	1.2
C1	20.03
C2	4.8
C3	6.5
C7+	66.05

Table 5 The comparison of the MMP correlation

Correlation	MMP (Bar)
Alston	68
Glaso	45

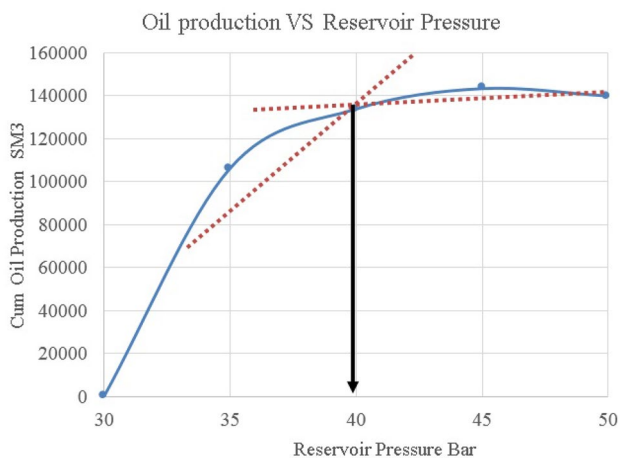


Fig. 6 Cumulative oil production versus initial reservoir pressure

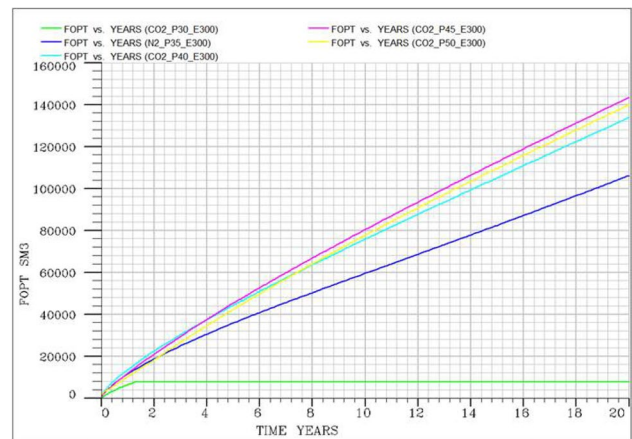


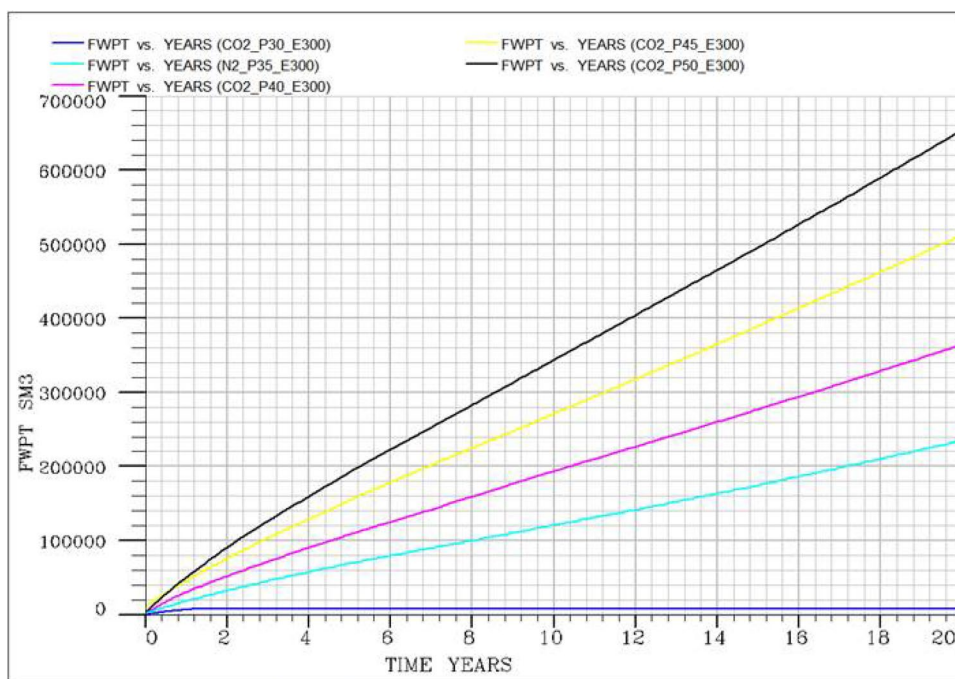
Fig. 7 Field oil production total versus years with reservoir pressure

Figure 6 shows that the MMP of this reservoir is at 40 Bar. The MMP was obtained from the point at which two straight lines intersected, as shown in Fig. 6. The correlation calculations show that the MMP of the reservoir is close with Glaso correlation with 45 Bar. This means that the miscibility of the reservoir is assumed to start at pressure above 4 bar. Therefore, it shows that the model is valid. Please refer to data of Figs. 7, 8, 9 and 10.

Effect of reservoir temperature

Reservoir temperature is also a crucial factor to be taken into account in the production recovery. Thus, the initial reservoir temperature was varied to see the effect of the temperature on oil production in the reservoir with constant CO₂ injection rate. The initial reservoir temperature was tested from 110 to 160 °C while maintaining other parameter constants. Figure 11 describes the oil production increased with increasing reservoir temperature from 110 to 160 °C. This is because with CO₂ injection and temperature increases, the kinetic energy of CO₂ molecules increased, which result in more interaction with the residual oil in the reservoir, thus increased in oil production. In addition to that, the production increased with reservoir temperature because the reservoir is located at a deeper depth where it retains its supercritical CO₂. With increased reservoir temperature, it also results in an increase formation pressure and hence leads to an increase in recovery. Reservoir temperature must be increased to avoid the complication of hydrocarbon production, which can lead to losses of valuable product in the

Fig. 8 FWPT versus years for reservoir pressure at 30 bar, 35 bar, 40 bar, 45 bar and 50 bar



hydrocarbon. Figure 12 shows the field oil production total increased as temperature increased with time. Figure 13 states the FWPT versus years for reservoir temperature for 110 °C, 120 °C, 130 °C, 140 °C, 150 °C, 160 °C, and Fig. 14 shows the reservoir simulation of reservoir temperature distribution at 110, 130, 150 and 160 °C

Effect of carbon dioxide injection rate

The permeability of the reservoir is the ability of fluid flow through the reservoir. Transmissibility is the degree of the fluid that can flow with respect to permeability. From Fig. 15, it shows that the permeability transmissibility percentage increased with increased in reservoir permeability. This is because with higher permeability, more fluid can flow through and more oil will be produced.

However, with implementation of CO₂ injection (Fig. 16), additional oil can be produced when compared with natural drive production. From Fig. 17, it shows that with increasing injection rate, more production will be produced. This is because as oil mixed with CO₂ gas, the oil swelled and results in lower interfacial tension and viscosity. This more oil will be recovery. The drop of the production at the end of the data might be due to early gas breakthrough.

Figure 18 shows FWPT versus year for CO₂ injection rate at 500 sm³/day, 600 sm³/day, 700 sm³/day, 800 sm³/day and 900 sm³/day and FWPT nearly linearly increases with injection rate for all flow rate.

Figure 19 shows reservoir simulation of CO₂ injection rate distribution of 500 sm³/day at 2019, 2025, 2029 and 2038. The change in contour color states the concentration change.

Therefore, from Table 6, it can be confirmed that oil production is higher with miscible CO₂ injection when compared with naturally producing reservoir.

Comparison of EOR

Figure 20 illustrates the comparison between the cumulative oil productions for 20 years at 500 sm³/day for CO₂ and WAG injections. It shows that WAG injection initially produced higher than CO₂ injection. However, at year 16 the cumulative oil production for WAG injection started to produce lesser compared to CO₂ injection where production continues to increase. This might be due to early water breakthrough to the production well in WAG injection.

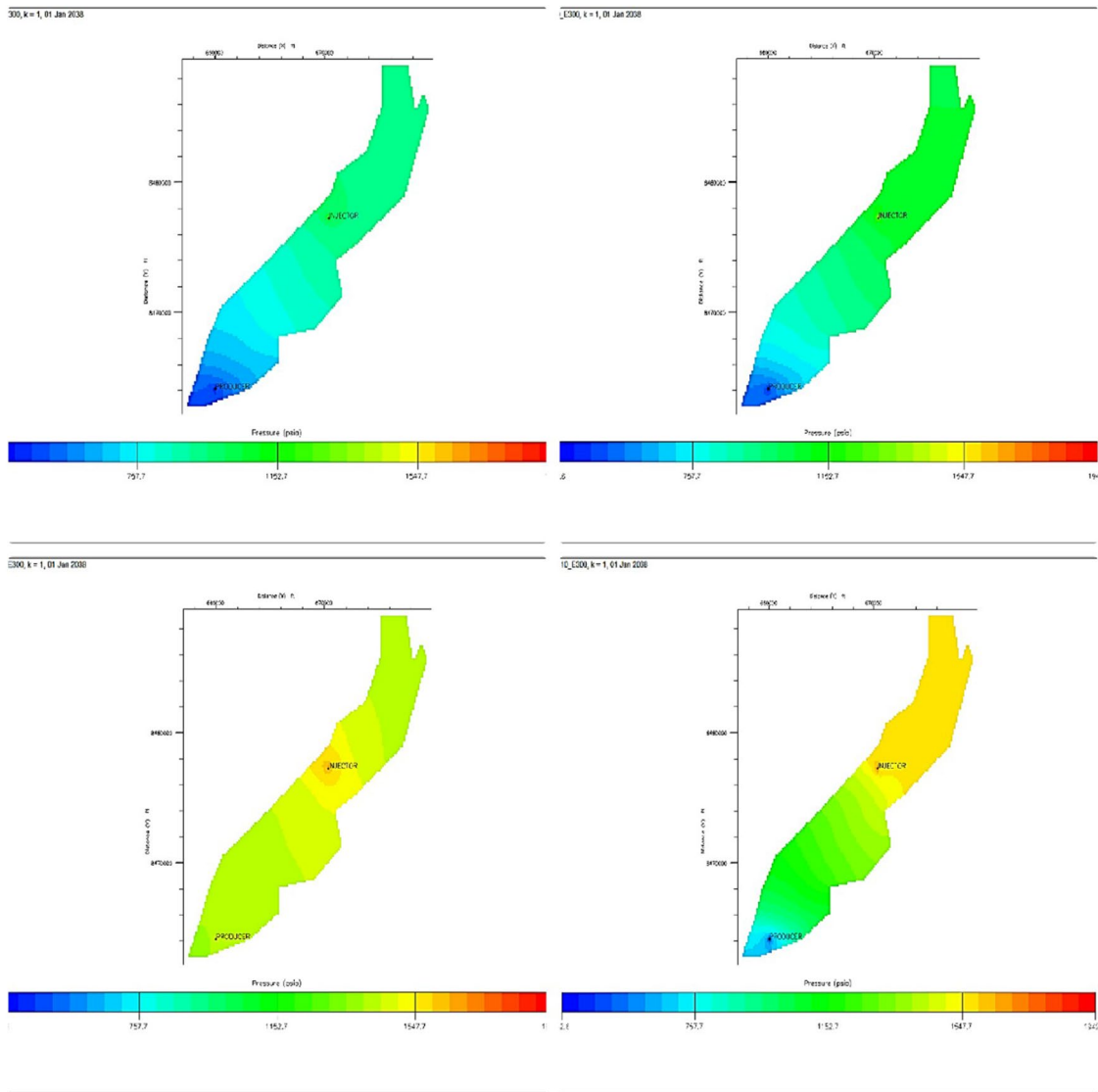


Fig. 9 Left to right: reservoir simulation of reservoir pressure distribution at 60 Bar, 70 Bar, 90 Bar and 110 Bar

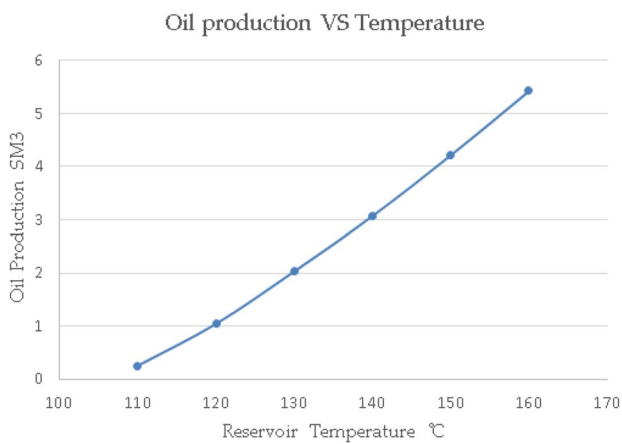


Fig. 10 Oil production versus initial reservoir temperature

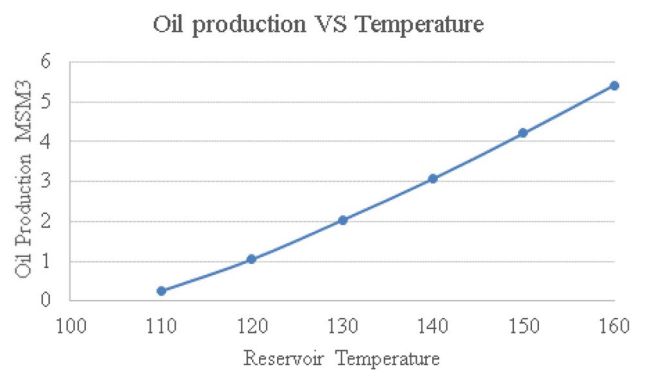


Fig. 11 Cumulative oil production versus initial reservoir temperature

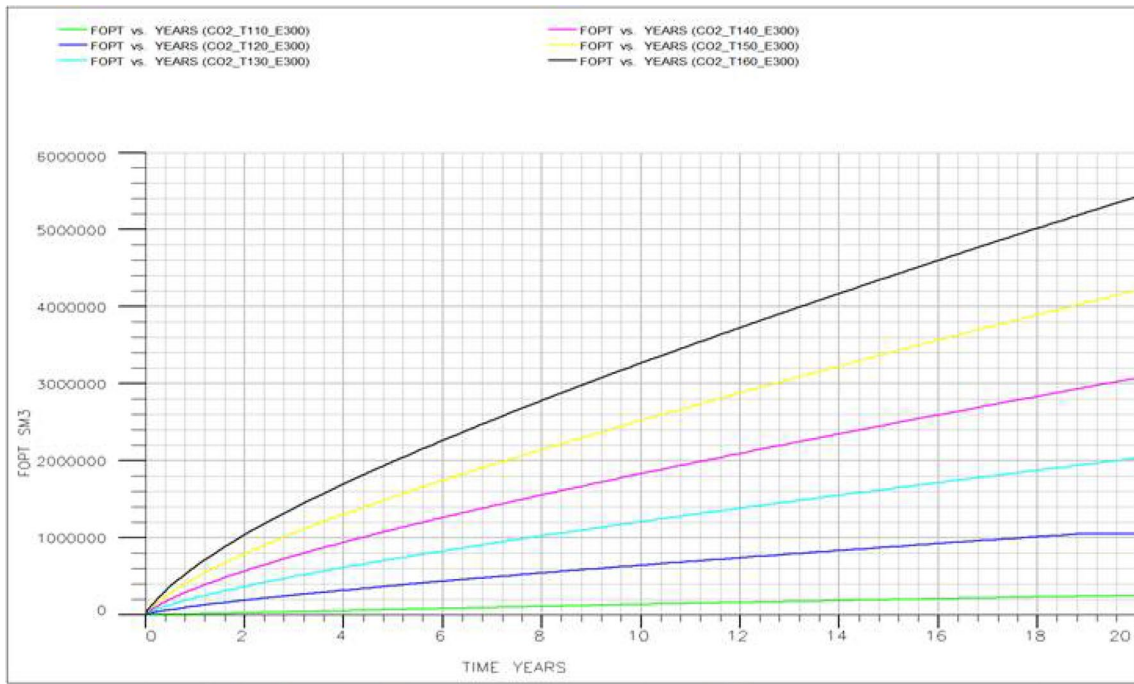


Fig. 12 Field oil production total versus years with reservoir temperature

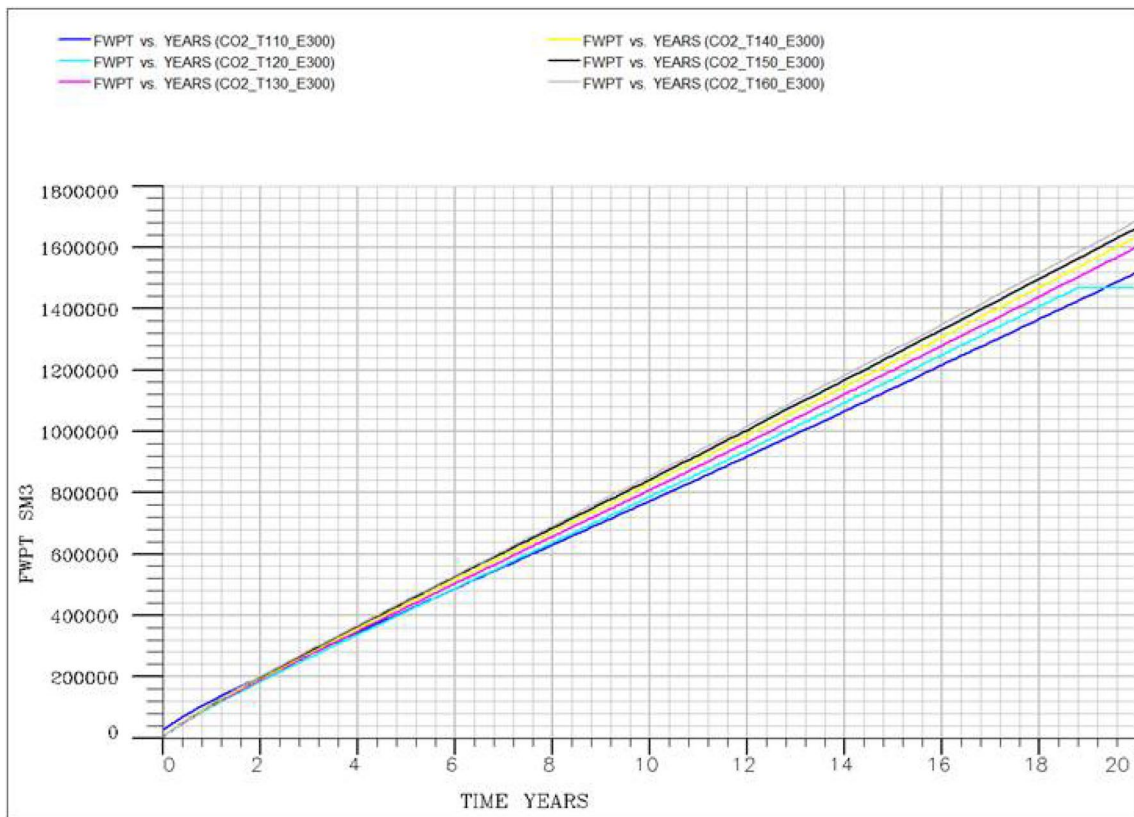


Fig. 13 FWPT versus years for reservoir temperature for 110 °C, 120 °C, 130 °C, 140 °C, 150 °C, 160 °C

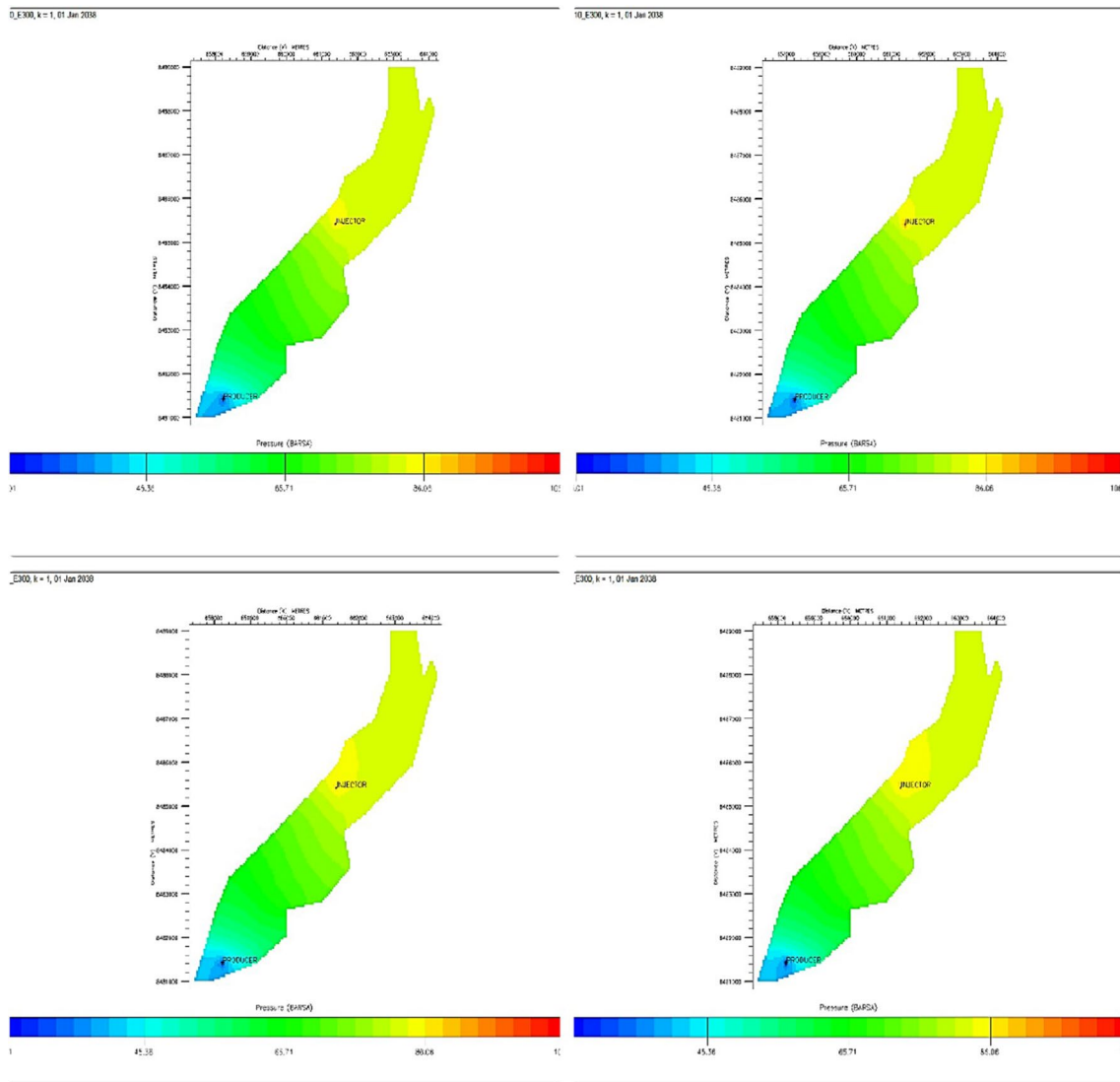


Fig. 14 Left to right: reservoir simulation of reservoir temperature distribution at 110, 130, 150 and 160 °C

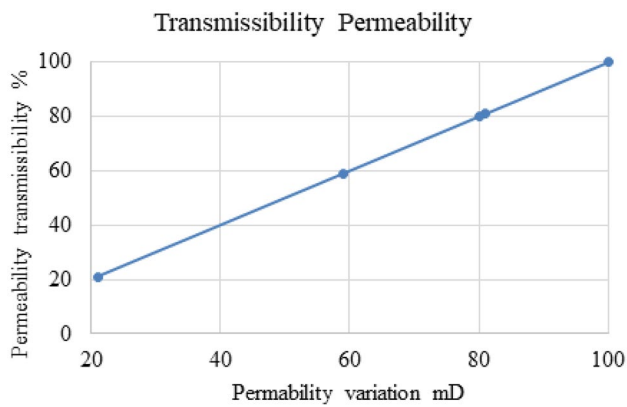


Fig. 15 Variation of transmissibility permeability

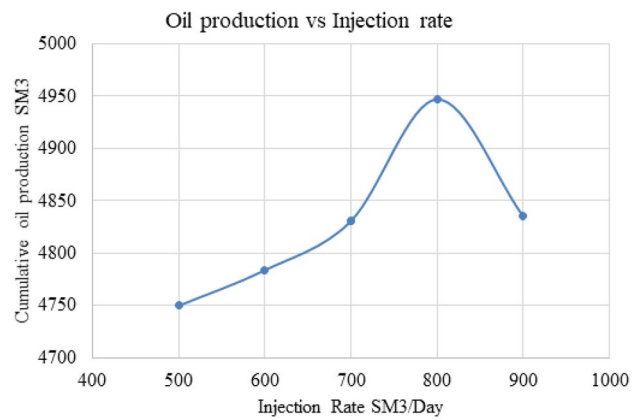


Fig. 16 Oil production versus CO₂ injection rate

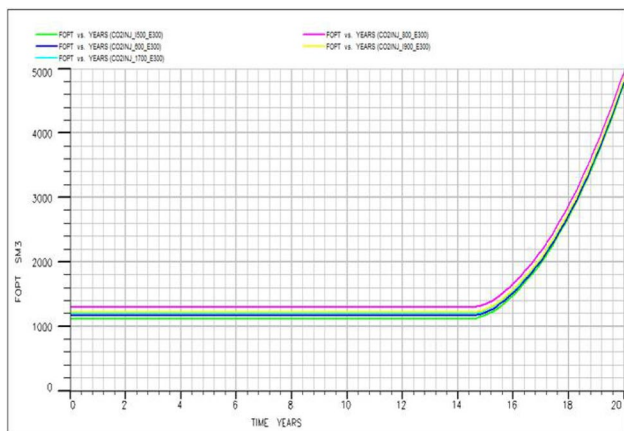


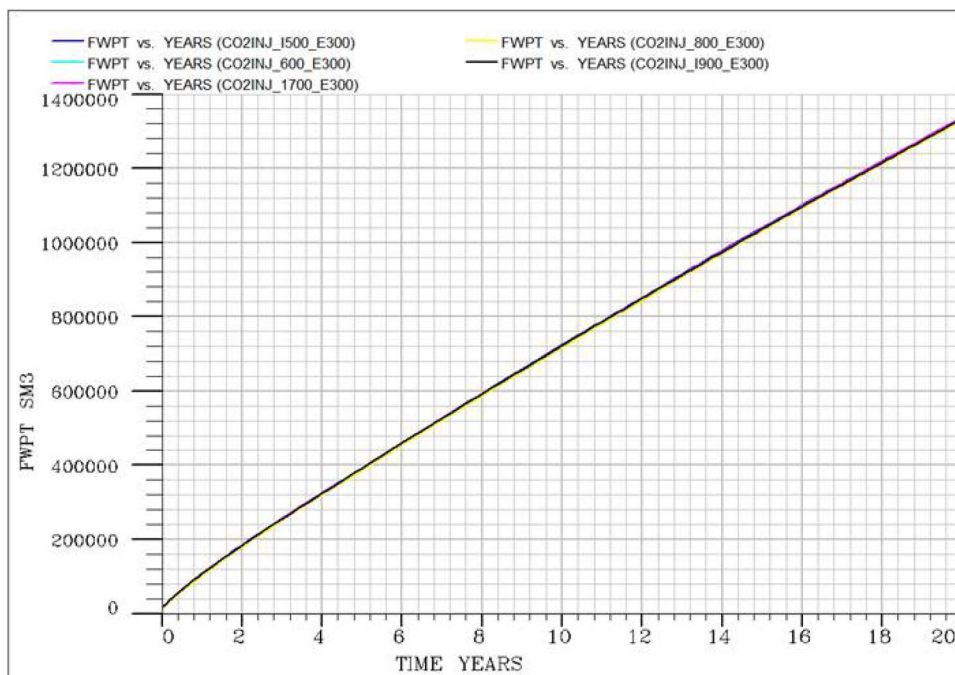
Fig. 17 Field oil production total versus years with CO₂ injection rate

Conclusions

This concludes few important findings:

1. MMP of this reservoir is at 38 Bar where oil production starts to produce.

Fig. 18 FWPT versus year for CO₂ injection rate at 500 sm³/day, 600 sm³/day, 700 sm³/day, 800 sm³/day and 900 sm³/day



2. It shows that reservoir pressure, reservoir temperature and injection rate are very important factors to be considered in petroleum reservoir for recovery and determining its effects on the oil production in the reservoir. These factors are analyzed to determine the optimum pressure, temperature and injection rate to be able to achieve higher oil recovery.
3. The production increased with an increase reservoir pressure and reservoir temperature. See Figs. 6 and 10.
4. CO₂ injection rate is also a crucial factor that boosts the recovery factor. The oil production increases with an increase CO₂ injection rate. The ultimate CO₂ injection rate is at 800 sm³/day.
5. It shows that CO₂ injection can boost the oil production in the reservoir when compared with naturally producing reservoir. Therefore, it proves that miscible CO₂ injection is a feasible method to be used in boosting recovery factor.
6. Table 7 shows that by injecting CO₂, the production is a boost when compared with natural drive production.

Hence, this paper contributes to the knowledge gap present in the Cornea Field since no CO₂ injection simulation

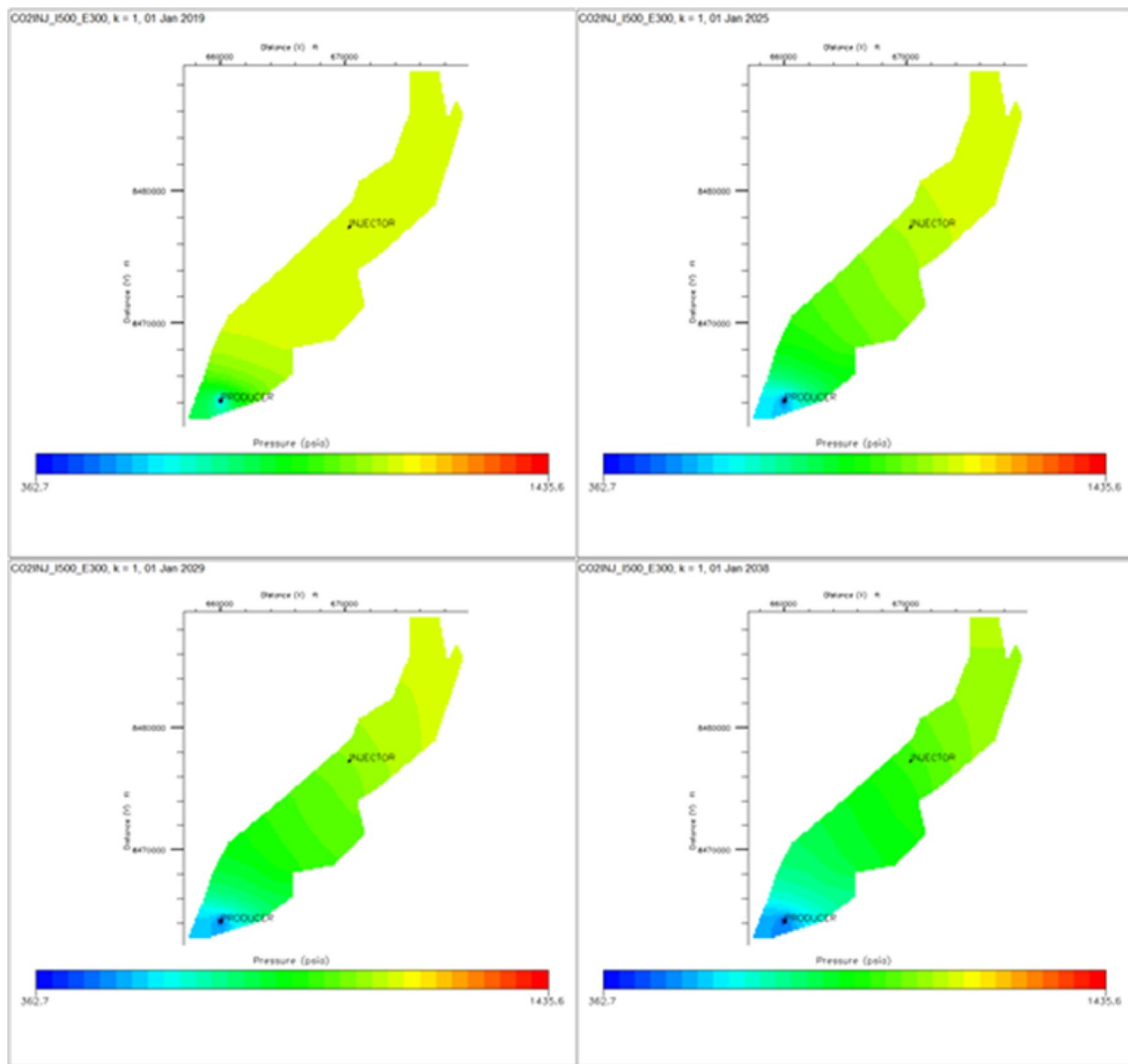


Fig. 19 Left to right: reservoir simulation of CO₂ injection rate distribution of 500 sm³/day at 2019, 2025, 2029 and 2038

was done before. Economic analysis was not included in the research. Also, for further improvement in oil recovery, it is recommended that more study needed to be done, such as implementing water alternating gas (WAG) to improve further the production. This article is produced with the donated software of Schlumberger Brunei/Malaysia (petrel and eclipse).

Table 6 Oil production comparison for production with and without CO₂ injection

	Method	Oil production KSM ³
1	Natural pressure depletion	2
2	CO ₂ injection	13

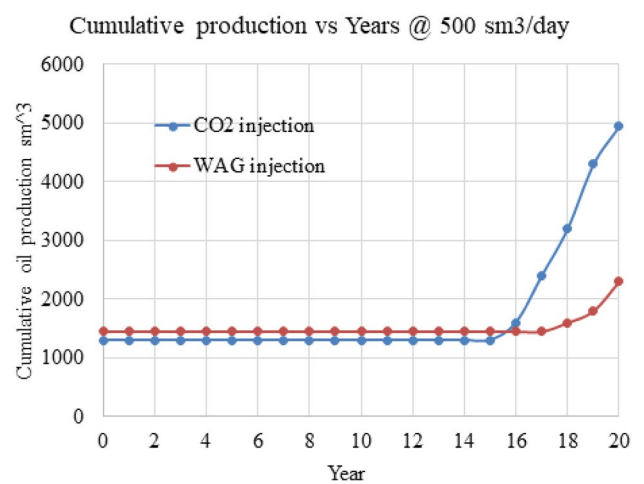


Fig. 20 Cumulative production versus Years @ 500 sm³/day

Table 7 Oil production comparison for production with and without injection

Method	Oil production SM3
Natural pressure depletion	2200
injection	4950

Funding These results are produced using Schlumber's donated (free for academics) software.

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