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Enhanced Oil Recovery through Carbon dioxide Injection: A Compositional Simulation Approach

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ABSTRACT

Primary recovery techniques of hydrocarbons are insufficient to meet the ever-growing energy demand. This fact encourages researchers to establish secondary hydrocarbon extraction techniques to increase production and meet the energy demand. The implementation of CO_2 flooding has been widely regarded as a highly favorable approach for enhancing the recovery of both light and heavy oil resources. The rate of CO_2 injection must be consistent so that viscosity decreases, and medium crude oil mobility is increased in accordance with production requirements. In this research, the compositional simulation model for CO_2 flooding has been developed using Eclipse 2010.1 software with Lorentz-Bray-Clark correlation for enhanced oil recovery by reducing viscosity with constant CO_2 injection. The compositional reservoir simulated model was executed from January 1, 2027 to January 1, 2050. From January 1, 2027 to January 1, 2048, the oil production rate remained constant. The concentration of CO_2 in the oil phase has exhibited a notable increase, rising from 27.25% to 58.658% over the course of the twenty-three-year simulation period. This observation indicates that the oil phase has experienced a greater dissolution of CO_2. Consequently, there has been a reduction in the viscosity of the reservoir oil, with a decrease from 0.126 centipoise (cp) to 0.088 cp, representing a 69.84 percent decline. Additionally, there has been an increase in the mobility of the reservoir oil. Furthermore, the enhanced oil recovery technique successfully achieved the recovery of 35.77 million stock tank barrels per day of medium crude oil. Finally, CO_2 flooding reduces the amount of CO_2 in nature, which is extremely significant from an environmental standpoint.

1. Introduction

Energy consumption is expanding at an exponential rate, but hydrocarbon availability is falling by the day [1–3]. Furthermore, the extraction of hydrocarbons by primary extraction methods is inadequate to fulfill the increasing demand for energy. This fact encourages researchers to establish

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secondary hydrocarbon extraction methods in order to maximize production and meet the world's energy needs [4].

The presence of unrecovered oil in a pore space despite having any relationship due to capillary forces is referred to as residual oil saturation. The primary goal of secondary recovery techniques or Enhanced Oil Recovery (EOR) techniques is to mobilize remaining oil so that it can participate in production, hence improving the rate of oil productivity. EOR methods are divided into four classifications. Thermal, chemical, gaseous, and more types are available.

The term "thermal flooding" refers to injection procedures that convey heat into a reservoir. Thermal methods can be applied in three ways: steam soak, steam drive, and in-situ combustion [5-7]. Thermal recovery is applied in the production of Oils that are viscous and thick, with API gravities less than 20 [8]. The drop in viscosity for very heavy crudes (less than 10°API) is significant, but not sufficient to allow them to flow economically. Chemical flooding is a technique that entails the utilization of chemicals to enhance the efficiency of either fluid displacement or sweep in the process of fluid replacement. Chemical compounds commonly employed in various applications include alkalis, surfactants, polymers, gels, emulsions, as well as their combinations, such as alkali-polymer, surfactant-polymer, and alkali-surfactant-polymer, among others [9–11]. There are also some additional EOR approaches for increasing the sweeping efficiency of the displacing fluids. The most commonly employed techniques in this context include water injection at the gas-oil interface, cyclic injection of water and gas, and microbiological interventions [12–13].

Gas injection is a tertiary recovery technique that involves the injection of natural gas, nitrogen, or carbon dioxide into the reservoir. The gases and drive gas have the potential to either undergo expansion within the reservoir or interact with the oil by means of mixing or dissolution. These processes result in a reduction in viscosity and an enhancement in flow characteristics. Gas injection can be exemplified by various scenarios, including the miscibility of CO_2, immiscibility of CO_2, miscibility of N_2, miscibility of rich gas, miscibility of dry gas, and miscibility of LPG [14–15]. CO_2 flooding is considered to be a highly promising approach for enhancing the recovery of both light and heavy oil. In the context of oil recovery, it is common practice to maintain a constant production pressure during CO_2 flooding in order to ensure the miscibility between the injected CO_2 and crude oil. However, in the case of heavy oil recovery, implementing a declining pressure scheme may have the potential to induce foamy oil flow, thereby potentially enhancing the overall oil recovery process. Viscosity reduction is the most significant mechanism of CO_2 techniques in heavy oil. Despite the limited miscibility of CO_2 in heavy oil, it has been asserted that the partial dissolution of CO_2 can lead to a significant reduction in heavy oil viscosity, potentially by a factor of 10 [16]. Nowadays, researchers are more interested in CO_2 flooding since it reduces the amount of CO_2 in nature, which is highly important from an environmental standpoint. Furthermore, Injection of CO_2 gas can be a low-cost method of disposing of uneconomical produced gases from an oil reservoir.

Recent researches are focusing on CO_2 injection. In their study, Yu et al. (2005) employed numerical reservoir modeling techniques to simulate the injection of CO_2 as a huff-and-puff process. The researchers utilized typical Bakken reservoir and fracture parameters in order to enhance oil recovery [17]. In their comprehensive study, Alvarado and Manrique (2010) conduct a thorough assessment of the enhanced oil recovery (EOR) status and potential for increasing ultimate recovery factors in various reservoirs, spanning from extra heavy oil to gas condensate. The authors examine the efficacy of different techniques, including CO_2 injection, high pressure air injection (HPAI), and chemical flooding, in achieving this objective [6]. In another study, the feasibility of employing cyclic CO_2 injection as a means to enhance recovery factors in shale oil reservoirs [18]. Perera et al. (2016) are currently engaged in an extensive examination of the CO_2-EOR (Enhanced oil recovery) procedure, employing the CO_2-Prophet simulator for the purpose of 3-D numerical modeling [19].

Based on the findings presented, it is observed that there exists a positive correlation between the rate and volume of CO_2 injection (measured in HCPV - Hydrocarbon pore volume) as well as the reservoir temperature, and the subsequent increase in oil production during pure CO_2 injection. Safi et al. (2016) create a numerical simulation of subsurface flow in an EOR system utilizing Nitec, LLC's multiphase flow solver programme COZView/COZSim [20]. The study conducted by Almobarak et al. (2021) offers valuable insights into the mitigation of minimum miscibility pressure (MMP) through the introduction of chemical agents into the CO_2 phase [21]. According to Massarweh and Abushaikha (2022), continuous CO_2 flooding is challenging due to unfavorable mobility, viscous fingering/channeling, and early CO_2 breakthrough, particularly in the presence of reservoir heterogeneities [22].

In short, modern researchers are working on numerical reservoir modeling, 3-D numerical modeling, and the multiphase flow solver program COZView/COZSim to improve oil recovery factors by injecting CO_2 while taking reservoir heterogeneity, minimum miscibility pressure, and fracture 2parameters in consideration. However, in this study, we created a compositional simulation model for CO_2 flooding with Lorentz-Bray-Clark correlation using Eclipse 2010.1 software for enhanced oil recovery by reducing viscosity with constant CO_2 injection. Here, Four CO_2 injection wells were positioned around the reservoir's perimeter while one oil production well was positioned in the reservoir's middle. The optimal CO_2 injection rate for achieving maximum oil production is determined to be 500 thousand standard cubic feet per day (MSCF/D) at a pressure of 3100 pounds per square inch (psi) through a single well. Correspondingly, the most favorable oil production rate is observed to be 4900 stock tank barrels per day (STB/D). The compositional reservoir simulation model was utilized to simulate the time period spanning from January 01, 2027, to January 01, 2050. From January 1, 2027, to January 1, 2048, the oil production rate remained constant. The compositional reservoir simulator has perfectly generated the CO_2 injection mechanisms. CO_2 concentration in oil phase has increased from 27.25% to 58.658% which indicates that more CO_2 was dissolved in oil phase within the twenty-three years of simulation. The viscosity of reservoir oil is 0.126 cp at the beginning of CO_2 injection and at the end of CO_2 injection the viscosity of reservoir oil is 0. 088 cp. The reduction of viscosity has been observed in the oil phase by the dissolution of CO_2 in oil phase and the oil viscosity has reduced by 69.84%.

2. Methodology

Compositional simulation is used for reservoir simulation and prediction of recovery when a fluid sample includes two or more hydrocarbons that display distinctively different phase and composition changes relative to temperature and pressure. To observe the dynamic characteristics of the reservoir under an optimal enhanced oil recovery program, the simulation model predicts reservoir pressure profile, viscosity profile, bottom hole pressure profile, gas injection rate, oil production rate, dissolution of gas profile, and total recovery factor profile. Eclipse (Version: 2010.1) software was utilized here for compositional simulation.

Development of compositional simulation model requires some pre-processing settings. In pre-processing settings there are six sections in DATA File. The flowchart of pre-processing settings is given below in Figure 1.

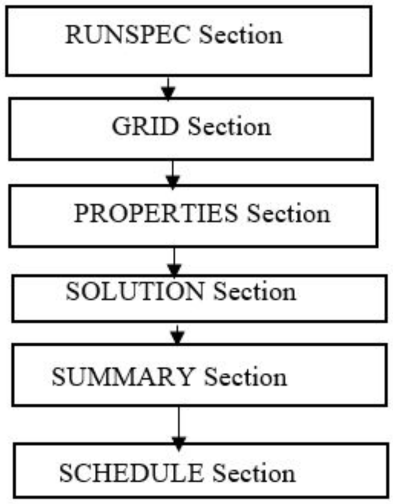


Fig. 1. Pre-processing settings of compositional simulation model

The first section of pre-processing settings of ECLIPSE is the RUNSPEC section. It includes information about the run title, start date, units, problem dimensions (such as the number of blocks, wells, tables, etc.) that indicate the presence of phases or components, and option changes. The GRID portion specifies the simulation grid's basic geometry as well as numerous rock attributes. The reservoir fluids and rocks' pressure and saturation dependent properties are listed in the PROPERTIES portion of the input data. The RPTSOL keyword guides the initial solution's output to the Print file in the SOLUTION section. The SUMMARY section defines which variables should be written to Summary files after each time step of the simulation. The outcome that is wanted must be mentioned in this section. The SCHEDULE part provides the computer-simulated processes (controls and limitations for production and injection) as well as the periods when output reports are required. Compositional simulation model also requires developing reservoir grid model, absolute permeability model, porosity model, shale content model, reservoir fluid composition and thermodynamic properties of reservoir fluid. The input parameters of these models are given below:

- **Reservoir grid model**

In each grid cell, the reservoir grid model incorporated the geometry of the reservoir structure as well as numerous geological attributes. The reservoir structure had been constructed using seismic and well log data. Table 1 shows the reservoir grid model that had been developed using a geostatistical technique.

Table 1
Reservoir grid model

Number of Grid Cells	NX	NY	NZ
	30	30	20
Dimensions of Grid Cells	DX	DY	DZ
	100	100	100

- **Modeling of absolute permeability**

Absolute permeability is the measurement of permeability when the rock contains only one fluid or phase as determined by core analysis in the laboratory. Core samples were collected and processed from reservoir core barrels collected during the coring operation. Core samples were analyzed using a liquid permeameter. Table 2 shows the values that were discovered.

Table 2
Values of absolute permeability

Direction	X axis	Y axis	Z axis
Permeability	100	100	10

- **Modeling of porosity**

Porosity is a petro physical feature of rock that has been measured in a laboratory using core analysis. Core samples were generated from core barrels retrieved from the reservoir during the coring process. A mercury porosimeter was used to examine core samples. The porosity was then estimated, and the amount had been found is 20%. Porosity had been calculated by pore volume of the reservoir. The following parameters are included in the reservoir porosity model:

Pore volume of reservoir = (Bulk volume of reservoir * Porosity)
= (18000000000* 0.2)
= 3600000000

- **Modeling of shale content (NTG)**

The shale content of the reservoir rock is represented by the net to gross ratio. It is referred to as the fraction. If no shale is present in the reservoir rock, the value is 1.00, as estimated in the lab test. The NTG was calculated in the laboratory based on core analysis. Core samples were generated from core barrels retrieved from the reservoir during the coring process. The core samples were then cut up to determine the quantity of shale material. The NTG value was determined after measuring all of the shale material. For our research, the calculated NTG value was 0.8.

- **Oil compositions**

Crude oil is a mixture of comparatively volatile liquid hydrocarbons. The composition of crude oil which was used for lab test is shown in Table 3.

Table 3
Crude oil composition

Component Name	Formula	Mole Fraction
Carbon dioxide	CO_2	0.0002
Nitrogen	N_2	0.0034
Methane	C_1	0.3462
Ethane	C_2	0.0411
Propane	C_3	0.0101
iso-butane	IC_4	0.0076
Butane	NC_4	0.0049
iso-pentane	IC_5	0.0043
Pentane	NC_5	0.0021
Hexane	C_6	0.0161
Heptane+	C_7^+	0.5640

- **Critical Temperature**

The critical temperature of a substance refers to the temperature at which its vapor is unable to undergo liquefaction, irrespective of the magnitude of the applied pressure. Each substance possesses a critical temperature. Table 4 presents the critical temperature values associated with the utilization of various constituents found in crude oil.

Table 4
Critical temperature, pressure, and compressibility factor of crude oil component

Component	CO_2	N_2	C_1	C_2	C_3	IC_4	NC4	IC_5	NC_5	C_6	C_7^+
TCRIT	547.6	227.3	343.0	549.8	665.7	734.7	765.3	828.8	845.4	913.4	972.5
PCRIT	1070.6	493.0	667.8	707.8	616.3	529.1	550.7	490.4	488.6	436.9	396.8
ZCRIT	0.2742	0.2916	0.2884	0.2843	0.0804	0.2824	0.2736	0.2701	0.2623	0.2643	0.2633

- **Critical pressure**

A substance's critical pressure is the pressure required to liquefy a gas at its critical temperature. Table 4 shows the necessary pressure for using crude oil components.

- **Compressibility factor (Z)**

The compressibility factor (Z), represents a real gas's divergence from ideal gas behaviour. Table 4 shows compressibility factor values that are often calculated from equations of state (EOS) that utilise compound-specific empirical constants as input.

- **LBC coefficient**

According to Eclipse Software, for seeing viscosity reduction process there must be in need of LBC Coefficient. The viscosity coefficients applied by the Lorentz-Bray-Clark correlation must be adjusted for reservoir thermodynamics. The viscosity is calculated using a fourth-order polynomial with diminished density and must not be negative. There are five default values for the coefficients which are given in Table 5.

Table 5
LBC coefficient values of crude oil component

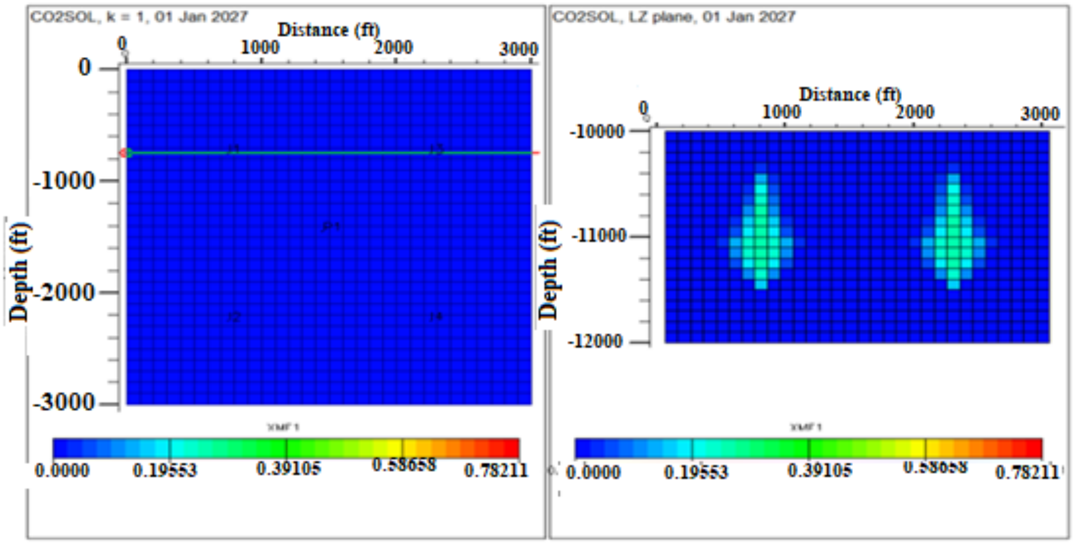
LBCCOEF	0.1023	0.023364	0.058533	-0.040758	0.0093324

3. Results and Discussion

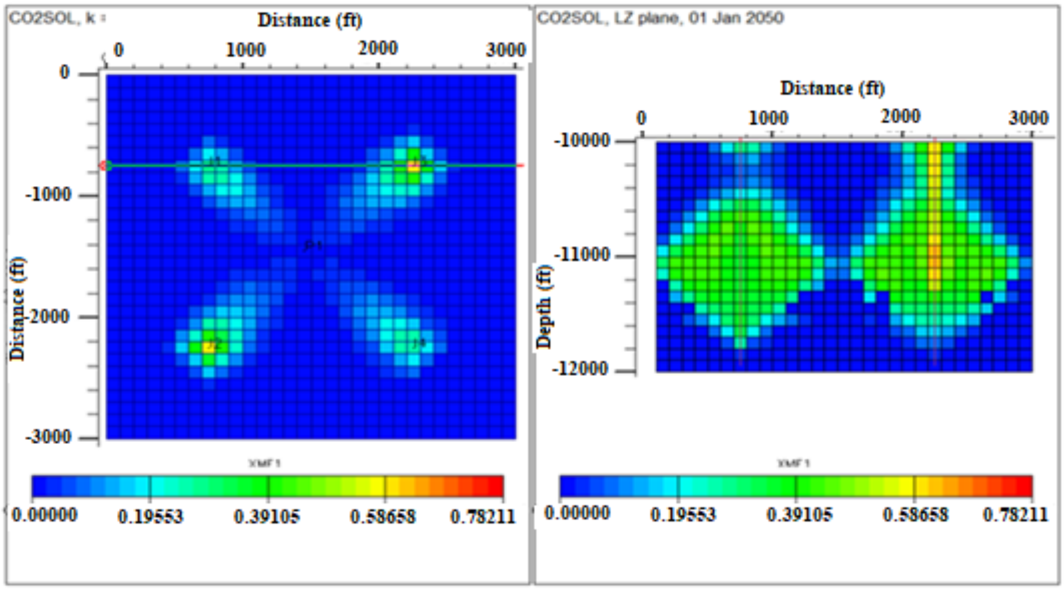
- **CO_2 Dissolution in Oil**

Mole fraction CO_2 in liquid phase means that when CO_2 dissolves in oil, the weight of the oil is reduced. As a result, by improving the lifting process, oil production will rise. The penetration distance will increase with time due to the dissolution of CO_2 in oil.

Figure 2 depicts the solubility of CO_2 in oil and the penetration distance from the wellbore. Figure 2 (a) shows that the mole fraction of CO_2 (XMF1) in liquid phase at the start of the simulation on January 1, 2027 was 0.2725 near the well bore. As indicated in Figure 2 (b), moderate amounts of CO_2 were dissolved in the oil phase, and CO_2 distributed about 300 feet from the well bore, which may be identified by color difference. Figure 2 (c) shows that a considerable amount of CO_2 was dissolved in the oil phase, with the mole fraction of CO_2 (XMF1) in the liquid phase at the end of the simulation on January 1, 2050 being 0.58658 near the well bore.



(a) (b)



(c) (d)

Fig. 2. Mole fraction CO_2 in liquid phase on 1st January 2027 (a and b) & 1st January 2050 (c and d)

Figure 2 (d) further illustrates that CO_2 was dispersed 600 feet around the well bore. After 23 years of simulation, the CO_2 concentration in the oil phase increased from 27.25% to 58.658%, indicating that more CO_2 was dissolved in the oil phase. Furthermore, the spreaders of CO_2 around the wellbore have increased from 300 feet to 600 feet, indicating that the hydrocarbon of oil is becoming lighter and more suitable for secondary recovery.

- **Immiscible Displacement**

Mole fraction CO_2 in gas phase represents the moderate amounts of CO_2 that dissolve in crude oil and form a miscible zone up to certain points. After a specific miscible limit, CO_2 does not dissolve, but instead forms an immiscible zone that provides sufficient pressure to the reservoir as a gas cap drive mechanism.

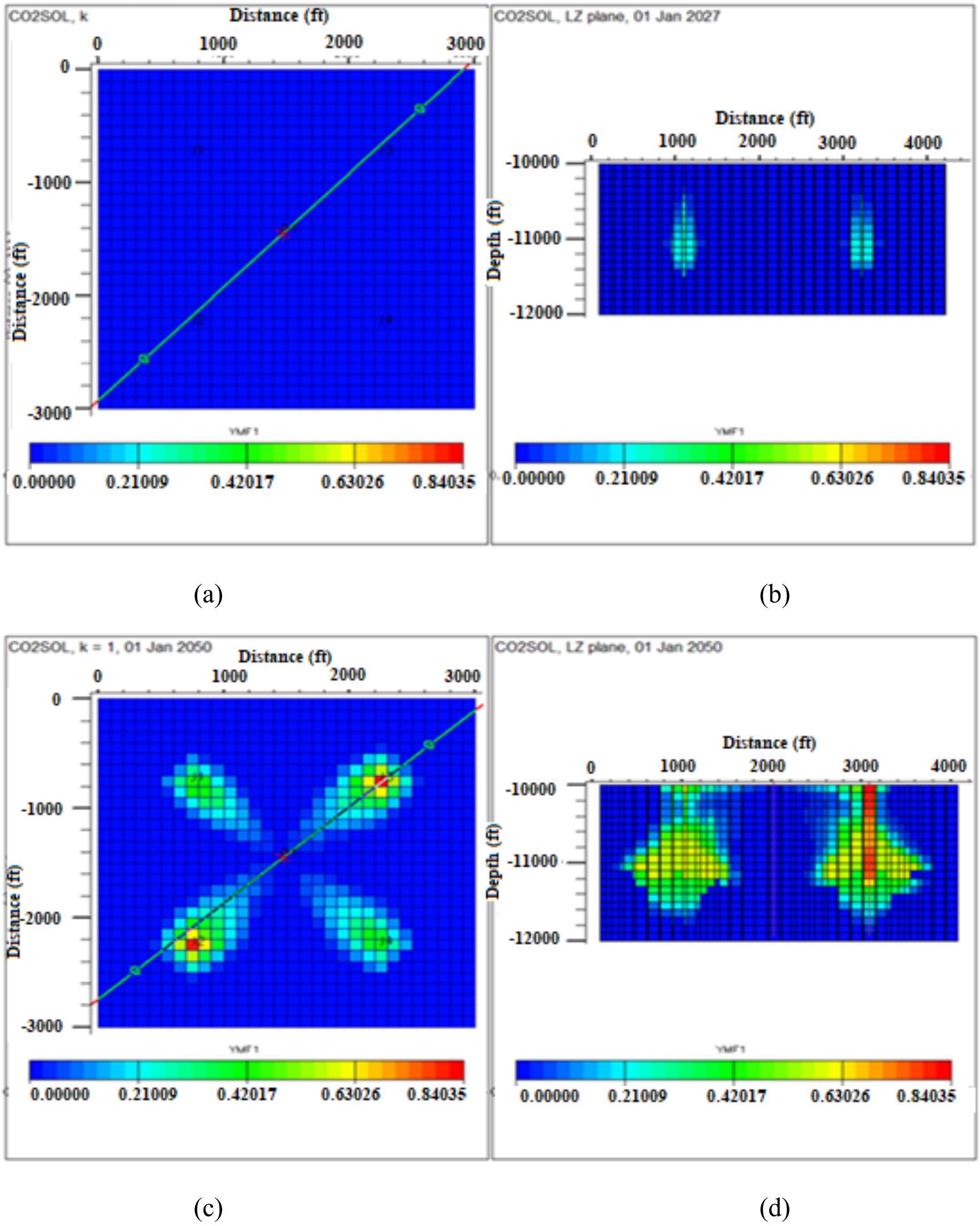


Fig. 3. Mole fraction CO_2 in gas phase on 1st January 2027 (a and b) & 1st January 2050 (c and d)

Figure 3 (a) indicates that the mole fraction of CO_2 (YMF1) in gas phase was 0.21009 near the well bore at the start of the simulation on January 1, 2027. Figure 3 (b) shows that CO_2 progress in the gas phase would be enhanced from 0% to 21%. Figure 3 (c) depicts the mole fraction of CO_2 in the gas component as of January 1, 2050. CO_2 would not have dissolved after a specific miscible limit but would have produced an immiscible zone to provide adequate pressure to the reservoir. In Figure 3 (d), the advancement of the immiscible zone would have been enhanced after 20 years of simulation, with the rate of advancement ranging from 21% to 84%.

- **Viscosity**

When CO_2 is continually injected through the injection wells, the viscosity of the oil decreases. The impact of reduced viscosity is increased oil mobility in the reservoir rock.

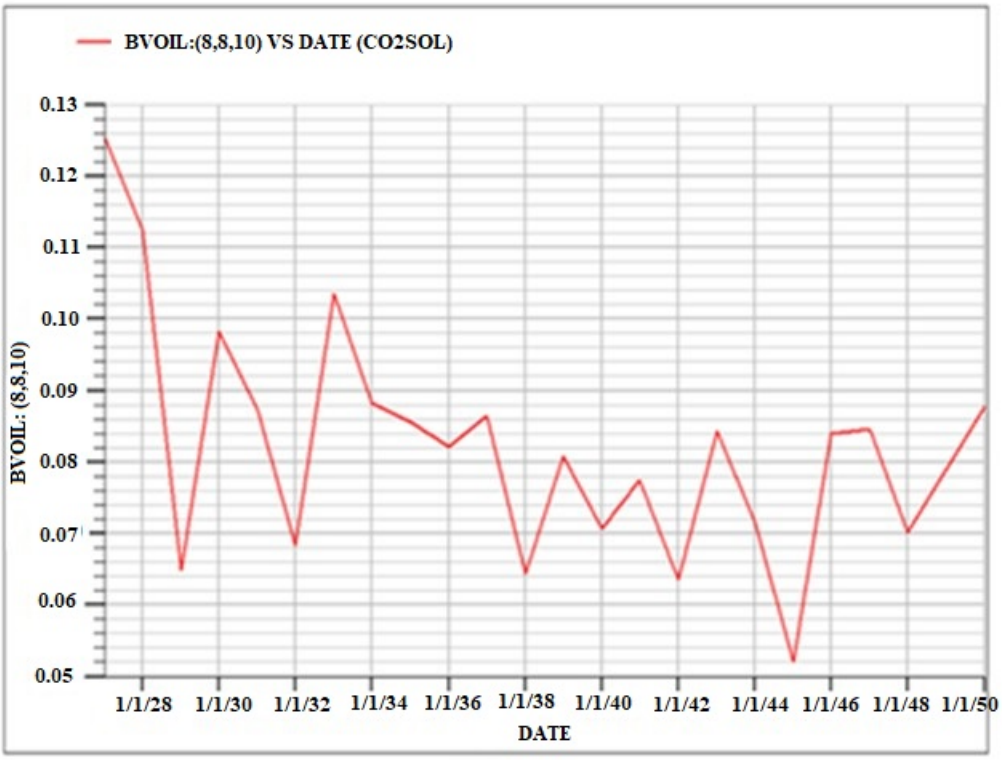


Fig. 4. Viscosity reduction profile

Figure 4 shows the reduction in oil viscosity caused by CO_2 injection. The viscosity of reservoir oil is 0.126 cp at the start of the simulation on January 1, 2027 and 0.088 cp at the completion of the simulation on January 1, 2050. The dissolving of CO_2 in the oil phase has resulted in a reduction of viscosity in the oil phase, with the oil viscosity decreasing by 69.84%.

- **Oil Production Rate**

Oil production rate means the smooth oil production in a constant rate which is known as play to rate production.

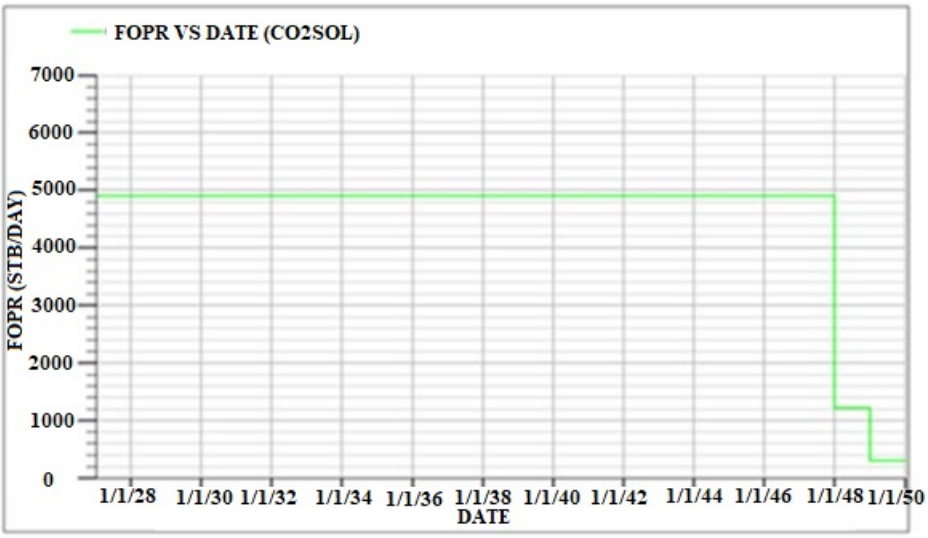


Fig. 5. Oil production rate profile

Figure 5 represents the results of a twenty-three-year simulation from January 1, 2027 to January 1, 2048. The oil production rate profile did not fall drastically until 2048, but there was a sharp fall because of the initiation of the production of dissolved gas through producing well.

- **Recovery Profile of reservoir oil**

The recovery profile of reservoir oil refers to the use of EOR procedures to increase oil production over time by reducing viscosity.

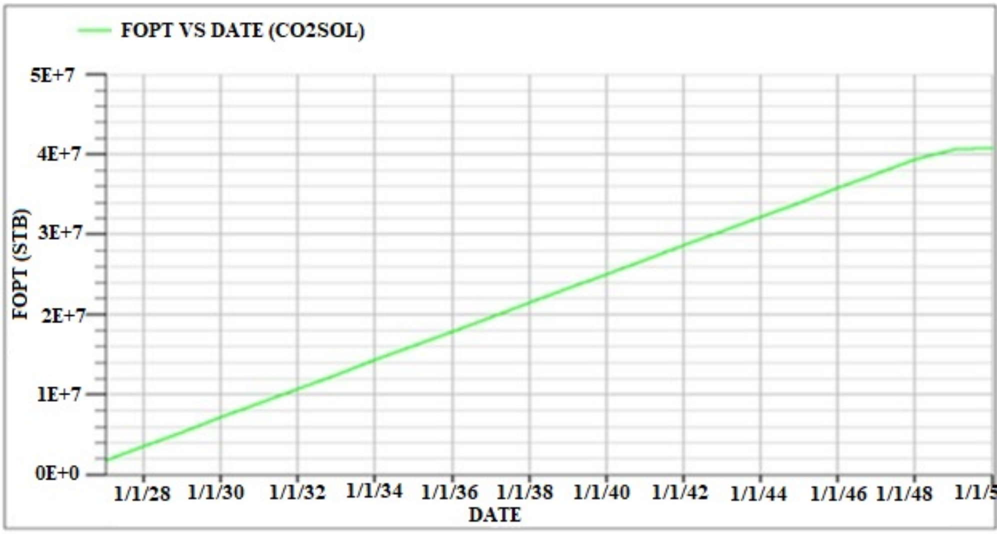


Fig. 6. Recovery profile of reservoir oil

Figure 6 describes the growing recovery profile of reservoir oil from January 1, 2027 to January 1, 2050. That is, using CO_2 injection to increase oil recovery helped to recover 35.77 million stb/day of medium crude oil.

4. Conclusions

There are various patterns for injection and production well placement. This well placement pattern must be chosen based on reservoir characteristics and production requirements in order to get higher oil recovery. The simulated reservoir was created by placing four CO_2 injection wells around the reservoir's periphery and one oil production well in the center. The CO_2 injection mechanisms were precisely created using the compositional reservoir simulator. The CO_2 injection rate must be consistent in order to reduce viscosity and increase the mobility of medium crude oil in accordance with production requirements. The concentration of CO_2 in the oil phase has increased, indicating that more CO_2 has been dissolved in the oil phase. CO_2 solubility in oil reduces viscosity, making the oil more mobile. The viscosity of the oil phase has been reduced by 69.84%. As a result, the viscosity reduction rate must be raised to achieve the desired oil production while minimizing pressure loss and maximizing oil recovery. Many oil fields in the United States have successfully used the CO_2 injection technique for enhanced oil recovery. The CO_2 injection technique has retrieved almost 29300 stb/day of crude oil in the SCACROC field. Again, the CO_2 injection technology was used to recover 22700 stb/day of crude oil at the Seminole field. Again, the CO_2 injection technique was used to extract 11600 stb/day of crude oil from the Rangely field. Finally, 6500 stb/day of crude oil has been obtained from the West Mallalieu field using CO_2 injection technology. However, in our research, 35.77 million stb/day of medium crude oil was recovered by viscosity reduction using CO_2 injection through compositional reservoir simulator. Furthermore, CO_2 flooding reduces the amount of CO_2 in nature, which is very important from an environmental standpoint. Capturing CO_2 from the environment and injecting it into reservoirs at a steady rate is challenging to maintain. Furthermore, the displacement of oil by CO_2 injection demands major expenditures. These are the major limitations of this study. Finally, the creation of reservoir simulation models, injection and production wells, rock properties, fluid properties, thermodynamic parameters, and oil composition must be incorporated effectively to ensure optimum recovery. The reservoir properties must be carefully programmed into the simulated model. CO_2 reaction simulation can be used for future CO_2-EOR research.

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