A Simulation Study on CO_2 Huff and Puff Method

1. **Yernar Tiyntayev (ID:201758733)**

2. **Omirzhan Tursymat (ID:201855911)**

Supervisor: Assoc. Prof. Dr. Changhong Gao

Petroleum Engineering Department

School of Mining and Geosciences

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Statement of the originality

We truthfully declare that this submitted work, entitled “Assessment of the Potential of Natural Surfactant in Carbonate Reservoir,” is a product of our original research work, to the best of our knowledge. The only exceptions are used published works and internet sources, presented as quotations and references that have been duly cited. Also, we declare that the report has not been previously published, in whole or in part, in any resources nor submitted for any other degree at Nazarbayev University.

Yernar Tiyntayev_______

Omirzhan Tursymat_______

SUPERVISOR: Assoc. Prof. Dr. Changhong Gao

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Abstract

In this study, the CO2 Huff and Puff method was investigated as a potential enhanced oil recovery technique. The CO2 Huff and Puff method is a promising enhanced oil recovery technique that utilizes carbon dioxide to improve sweep efficiency, mobility ratio and to reduce the oil viscosity that will enhance the oil production. In the modern world, more focus is being placed on the potential for CO2-EOR to enable geological CO2 storage because of the mounting demand to address climate change, which has elevated carbon capture to the forefront as a strategy for emission abatement. This method involves injecting CO2 into the reservoir, followed by a soaking period and a production phase, with the aim of improving the displacement of oil. The study utilized a reservoir simulation model on SMG software to evaluate the performance of the method, focusing on the impact of operational parameters such as number of cycles, injection rate, and soaking period on a tight reservoir with heavy oil. Results showed that increasing the number of cycles and injection rate improved oil production and recovery factor, with optimal values of 2 cycles for one base scenario and 3 cycles for the others, and an injection rate of 80 tons per day with incremental recovery of 15.98%. Additionally, a 30-day soaking period was found to be optimal for a particular reservoir with cumulative oil production of 81.95 MSTB and recovery factor of 22.52%. Overall, this study provides valuable insights for optimizing the application of the CO2 Huff and Puff method, contributing to the development of more efficient and sustainable oil recovery techniques.

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1. Introduction

1.1 Background

The resource of heavy oil refers to dense petroleum, and viscous with API gravity of 20 °API or less and a viscosity of more than 100 mPa·s (Speight, 2015). The expected total amount of heavy oil (4.3 BBL) and bitumen (6.5 BBL) that can be extracted is nearly equal to the rest of the reserves of light oil worldwide (Meyer & Attanasi, 2003). To cope with the constant rise in energy demand, the importance of heavy oil reserves will be raised soon. The extraction of heavy oil is constrained by two primary factors: excessive oil viscosity and the thickness of the oil pay zone is narrow. Excessive oil viscosity results in limited mobility of heavy oil in the extraction operation. Two types of techniques are mostly used to decrease crude oil's high viscosity. In the first technique, the high temperature of the injected fluids allows thermal procedures to be substantially more effective in reducing oil viscosity. These techniques consist of processes such as Steam Flooding, Cyclic Steam Stimulation, and in situ combustion, etc (Zhou et al. 2018). The second technique is non-thermal-solvent, which decreases the viscosity of oil by diluting the solvent with heavy oil. These techniques consist of processes such as Vapour Extraction, Cyclic Solvent Injection, and huff 'n' puff process, etc (Zhou et al. 2018).

Earlier research has established that most heavy oil reserves are located in low-productive zones (Srivastava et al.,1999). For instance, approximately 80% of the confirmed heavy oil deposits in the Western Canada Sedimentary Basin are in an oil production zone that is less than 5 m (Bowers & Drummond, 1997). As for deep deposits of heavy oil, the heat treatment-based extraction technique cannot considerably increase the extraction of heavy oil, since the quality of steam will reduce significantly when steam is pumped into the deep field: resulting in the thermal expansion in the field.

To prevent thermal-based approaches from being negatively impacted by thin or deep reservoir characteristics, a non-thermal-solvent extraction technique can be used to improve the heavy oil extraction in deep or thin heavy oil fields. Regarding the non-thermal-solvent technique, various gases may be applied as a solvent for injection. However, scientists have focused their attention on CO_2 solvents for several reasons. Laboratory investigations show that heavy oil may absorb CO_2, which will increase the industry's production of heavy oil (Gao et al., 2012). Compared to other solvents, CO_2 can operate at a significantly greater viscosity reduction ratio and saturation pressure under high pressure (Sankur & Emanuel, 1983). An increase in atmospheric carbon dioxide strengthens the natural greenhouse effect, which raises the earth's temperature. However, using technology without thermal dissolution, it is possible to significantly reduce the emission of CO_2 gas into the atmosphere.

Experience with CO_2-EOR over the last four decades has produced extensive information regarding the process's technical characteristics and financial advantages. For this technique, a lot has been learned about project design and reservoir management, lowering the risk and expense of project development. Nowadays, there is no doubt that CO_2-EOR may be a financially advantageous method to extend the life of a conventional oil field, allowing for the recovery of more precious resources. Enhancing recovery from current fields can also decrease the need to create new oilfields, which can be appealing to both governments and companies since it avoids the costs and environmental effects of doing so.

More focus is being placed on the potential for CO_2-EOR to enable geological CO_2 storage because of the mounting demand to address climate change, which has elevated carbon capture to the forefront as a strategy for emission abatement. Novel ways of CO_2-EOR might contribute to the achievement of a win-win solution for business and mitigate the effects of climate change by providing financial possibilities for oil producers, as well as assuring long-term storage of significant amounts of CO_2. As stated by Sahin et al. (2008), the CO_2 huff 'n' puff technique is the most effective since the recovery factor is high compared to other methods of CO_2 injection, such as continuous CO_2 injection, CO_2 water-alternating-gas injection, etc. The interfacial tension between the injected CO_2 and the residual oil almost disappears by implementing the CO_2 huff 'n' puff method when the reservoir pressure is greater than the minimum miscibility pressure. Additionally, implementing this technique activates production mechanisms such as reservoir re-pressurization, a decrease in viscosity, and solution gas drive. Moreover, the CO_2-rich oil phase swells and expands, becoming mobile. The CO_2 Huff and Puff method has been extremely successful in several field experiments. A pilot CO_2 "huff and puff" test conducted in the Canadian area of Lloydminster shows that the oil recovery has improved by 8–20%, or nearly 1.5 MMbbl of heavy oil (La Roche, 2017).

1. Research problem

The overall demand for all types of hydrocarbon resources rises as energy consumption continues to rise. Despite the extremely difficult oil extraction process from heavy oil reservoirs, heavy oil is currently developing into a very promising and important source of energy. In addition to the fact that the oil extraction from conventional basins is declining, huge reserves of heavy oil are more than 3 times the reserves of conventional oil, and enhanced oil recovery methods are being improved every year (Alboudwarej, 2006). The oil extraction in formations with heavy oil is low compared to oil extraction from conventional formations because of the physical constraint of the flow of oil through a porous medium. Since heavy oil deposits react ineffectively to secondary recovery. As a result, there is currently a need for further knowledge of the tertiary recovery methods for heavy oil reservoirs.

However, the implementation of cyclic gas injection in existing fields can reduce the burden on the development of new fields, minimizing the associated costs and environmental impact effects that could be a benefit for both governments and companies.

The concept of the cyclic gas injection technique to enhance oil recovery was designed a long time ago and achieved many successes in the oil production fields. For instance, the earliest pilot projects on the feasibility of CO_2 in heavy oil fields were carried out in the 1980s and 1990s and proved successful, but it is necessary to improve the design parameters of the cyclic gas injection process in heavy oil deposits (Zhou et al., 2019). The design parameters include CO_2 injection rate, CO_2 injection pressure, the quantity of CO_2 injection, well shut-in, and soaking time. This can be achieved through two approaches. One of them is a review of previous field cases. The second approach is reservoir simulation with varied design parameters.

2. Aims and Objectives

The study is aimed to improve the understanding of the CO_2 huff 'n' puff method, using a review of previous field cases, and simulating reservoirs with different porosity and permeability for cyclic injection of gaseous CO_2 by the huff and puff method with different design parameters. The design parameters will be optimized to maximize the hydrocarbon recovery and prevent emissions of injected CO_2 gas from the reservoir. Design parameters for optimization include operation parameters such as CO_2 injection rate, the quantity of CO_2 injection, and soaking time.

Objectives:

1. To improve understanding of the CO_2 huff 'n' puff method through a literature review on its mechanisms and field cases.
2. To improve the design parameters of the CO_2 huff 'n' puff process through reservoir simulation.
3. Maximize oil recovery using the CO_2 huff 'n' puff technique by providing sensitivity analysis on operational parameters of the CO_2 huff 'n' puff method.
4. Economic Analysis for CO_2 huff 'n' puff method

1.4 Justification of this research

Economic justification: The CO_2 EOR project requires investment money to be implemented. It entails modifying wells to function as both injectors and producers, setting up a CO_2 recycling facility and infrastructure for corrosion-resistant field production, and constructing pipelines for CO_2 collecting and conveyance. However, the purchase of CO_2 is typically the project expense with the highest overall cost. As a result, wherever feasible, operators work to optimize and lower the cost of its acquisition and injection. The total cost of producing a barrel of CO_2 (including purchase price and recycling charges) can range from 25 to 50 percent of that cost. The first CO_2 injection volume must be acquired well before the start of additional output, in addition to the high upfront capital expenses of a CO_2 supply/injection/recycling scheme. As a result, the return on investment for CO_2 EOR is often modest and has a long payoff period.

Technical justification: High-cost drilling, fracturing, and completion processes must be reduced given this low price of oil. Thus, it becomes increasingly crucial to use existing wellbores to increase the residual oil output. Taking into account several increased oil recovery techniques, the CO_2 huff, and puff approach is regarded as one of the most effective methods for enhancing oil recovery since the recovery factor is high compared to other methods of CO_2 injection, such as continuous CO_2 injection, CO_2 water-alternating-gas injection, etc. This technique is a cost-effective option for depleted single wells that have not yet been prepared for refracturing. It supplies the energy required to lift hydrocarbons in low-pressure zones and get them moving toward the wellbore. When exposed to typical well stimulation pressures, CO_2 demonstrates a hydrostatic head that is at least as high as that of fresh water, resulting in lower treatment pressures and reduced horsepower costs. A considerable rise in oil production often occurs when the CO_2 is shut-in in accordance with bottom-hole pressure and flows back to the surface. Oil viscosity and interfacial tension are reduced because of the CO_2 injection's swelling effects. The CO_2's energy serves as a driving mechanism to transport fluids to the producing wells.

Environmental justification: CO_2 can be stored inside the reservoir after the production of oil, which means we can reduce the amount of greenhouse gas. With the global agreement on carbon neutrality, it is advantageous to know that CO_2 can be stored and rely on the storage potential of basins. Cenovus started injecting CO_2 into the Weyburn field in October 2000 to increase the oil output (Ferguson et al., 2009). Apache adopted a similar strategy in 2005 and injected CO_2 into the Midale oilfield. During the project, 30 Mt CO_2 at the Weyburn field and 10 Mt CO_2 at the Midale field were stored (Ferguson et al., 2009). The main conclusions from this study are the effective integration of EOR operations with CO_2 storage. The twelve years of operation have proven through experience that the two systems can complement one another, precise CO_2 accounting is feasible, and permanent CO_2 storage is feasible.

2. Literature review

2.1 Processes and mechanisms of CO_2 huff 'n' puff method

2.1.1 Processes of CO_2 huff 'n' puff method

The CO_2 huff 'n' puff method was carried out in one well. As can be seen from figure 1, this technique is divided into three stages: the injection stage, the soaking stage, and the production stage (Zhou et al. 2018).

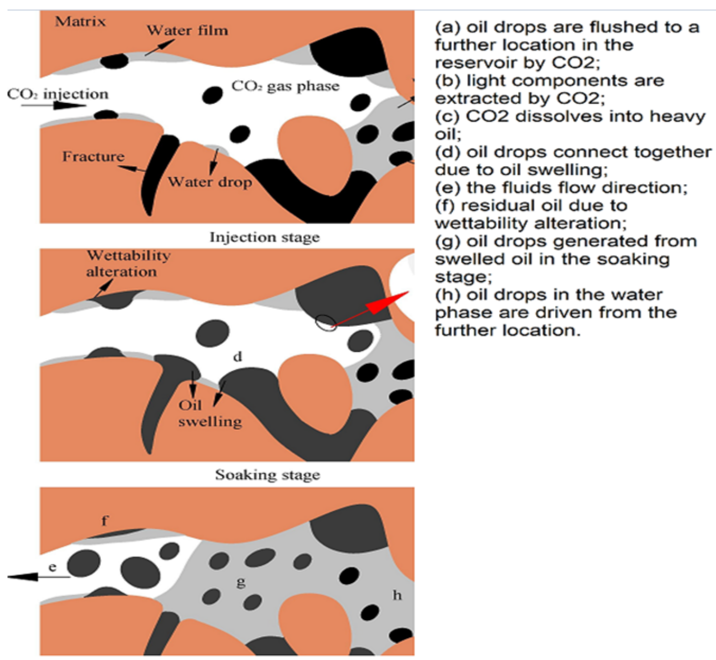


Figure 1. Three stages of the CO_2 huff 'n' puff process.

In the first stage, CO_2 is pumped into the target reservoir by a production well. Bypassing the immobile heavy oil, the pumped CO_2 forces some of the mobile heavy oil and water toward a different area of the formation, reducing water saturation near the wellbore and increasing the relative permeability of the heavy oil. Another part of the mobile heavy oil is exposed during the injection of CO_2 because it is blocked from pushing away close to the wellbore. (Yang, 2010) The process of CO_2 diffusion is insignificant at the injection phase since heavy oil does not have a particularly high CO_2 diffusion coefficient, this phase is short, and the CO_2 is pumped at a high rate. At the end of the injection phase, the pressure in the formation will be much higher than the formation pressure when the injection operation began.

In the second stage, the production well into which CO_2 was injected was shut down. The main processes of this technique in terms of oil swelling and decrease in viscosity occur due to CO_2 diffusion. A process of mass transfer of carbon dioxide into heavy oil and light components of this oil are released in a such way that the heavy oil volume grows up and decreases in viscosity.

In the third stage, when the well is open, some of the CO_2 is extracted in the gas phase since heavy oil does not dissolve all of the injected CO_2. The oil extraction is a result of oil swelling, a decrease in viscosity, a decrease of interfacial tension and changes in relative permeability consequent to the displacement of mobile water by CO_2. Oil swelling occurs over the entire contact area, resulting in an increase in the relative permeability of the oil. Also, interfacial tension and lower viscosity facilitate oil migration. Finally, due to the driving force created by the pressure decrease, heavy oil is extracted alongside the water phase from another site of the formation. Some of the swelled oil was washed off with movable water.

2.1.2 Mechanisms of CO_2 huff 'n' puff method

The CO_2 that is pumped into heavy oil formations is mostly in the immiscible state for two causes: the Minimum Miscible Pressure of heavy oil cannot be reached in the heavy oil field when the heavy oil has a gravity less than 30°API (Mangalsingh & Jagai, 1996) and the miscible displacement is impossible because there is no significant decrease in interfacial tension between the heavy oil and pumped CO_2. The oil swelling and viscosity decrease are the two primary mechanisms of production of heavy oil during the CO_2 huff 'n' puff technique.

2.1.2.1 Viscosity reduction

The key aspect of the CO_2 huff 'n' puff mechanism is the viscosity decrease. According to earlier research, viscosity reduction has a greater impact on heavy oil with a high density (Sakthipriya, 2022). The viscosity of the oil is drastically decreased when carbon dioxide is recombined with it. The primary causes of viscosity decrease with CO_2 injection include: the pumped CO_2 removes the particulate matter from the heavy oil; the pumped CO_2 dissolves the viscous deposits; viscous crude in oil is diluted with pumped CO_2; the pumped CO_2 is demulsified in heavy oil. A decrease in the viscosity of heavy oil leads to a shift in the fractional flow curve to the right. Thus, the fractional water flow is less than that before CO_2 injection, with the same water saturation. Meanwhile, the mobility of the oil and its connection increase, which leads to a relative increase in oil flow (Yuan, 2023). Heavy oil- CO_2 system's viscosity reduction ratio varies according to the temperature, pressure, and solubility of the dissolved CO_2 (Yuan, 2023). As can be seen from Figure 2, the viscosity of dead heavy oil drastically drops as the temperature rise, at 60 °C and 93 °C, the viscosity reduction ratios are 86.8% and 97.3%, respectively. As a result, the impact of temperature on the viscosity of the oil is noticeable.

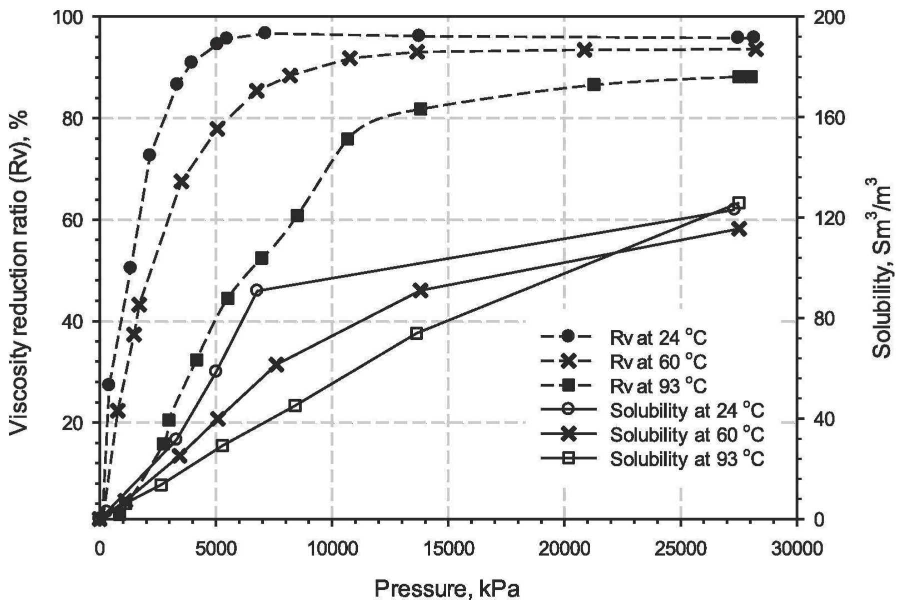


Figure 2. Viscosity reduction coefficient and solubility in the heavy oil- CO_2 system at various temperatures and pressures.

Because the mass transfer of the fluid phase is substantially slower than the phase of gas, viscosity reduction with CO_2 injection happens primarily at a smaller pressure at a lower than the critical temperature. As a result, the influence of pressure on CO_2 solubility is minimal.

As for the heavy oil- CO_2 system, the viscosity reduction efficiency reduces with an increase in temperature at the identical pressure due to the smaller solubility of CO_2 and viscosity at a higher temperature in heavy oil, resulting in a lower viscosity reduction potential. The viscosity reduction ratio rises with a rise in CO_2 solubility, meaning that a greater proportion of the heavy oil viscosity is lowered by pumping CO_2. The researched heavy oil has a viscosity reduction ratio that could reach 97%. Among various samples of heavy oil with higher viscosity of heavy oil, a higher viscosity reduction coefficient can be achieved. As for the identical sample of heavy oil, the viscosity reduction coefficient reduces with rising temperature.

2.1.2.2 Oil swelling

When CO_2 is pumped into heavy oil fields, a significant phenomenon is seen from the perspective of oil swelling since the pumped CO_2 dissolves in oil and enlarges the volume of heavy oil. Oil swelling is a significant mechanism for increasing oil recovery. Firstly, it has an advantage over moveable oil, and it is determined that the two have an inversely proportional relationship with the remaining oil saturation. Second, the heavy oil's mobility is increased. Thirdly, water will be forced out of the pore space by the drainage force created by the dissolved heavy oil. Fourthly, oil swelling could raise the oil saturation, leading to a rise in the relative permeability of the oil, which grows the fractional consumption of the oil phase at the extraction stage (Maneeintr et al., 2014). Pressure, temperature, and oil composition are all factors that influence how much the oil will swell. Figure 2 and Figure 3 show that the oil swelling coefficient graphs have similar tendencies as the CO_2 solubility graphs, implying that under identical conditions (pressure and temperature), the oil swelling coefficient is proportional to the solubility of CO_2.

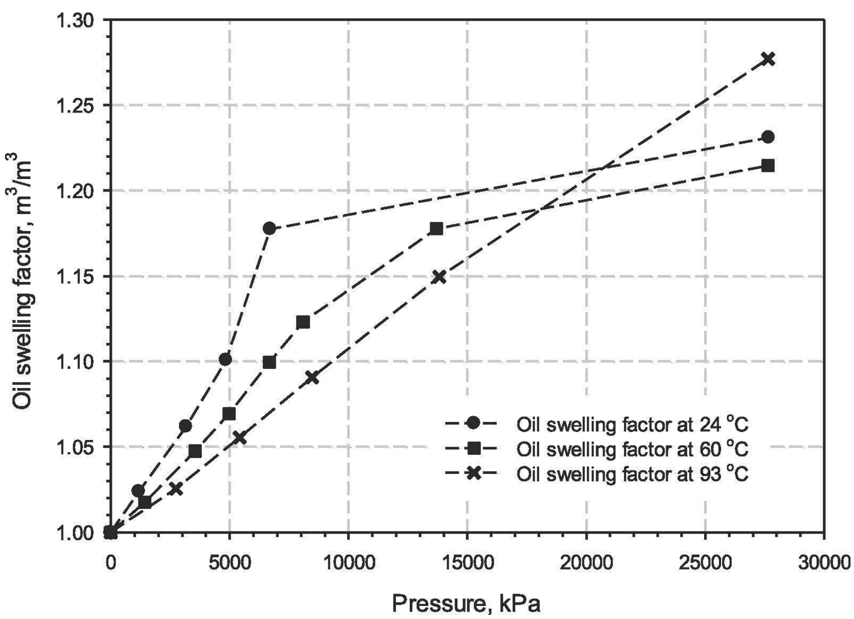


Figure 3. The oil swelling coefficient in the heavy oil- CO_2 system at various temperatures and pressures.

The impact of pressure on the oil swelling coefficient is different at various temperatures, and linear dependence is derived between the oil swelling coefficient and the pressure when the temperature exceeds the critical temperature. However, the CO_2 phase significantly affects the oil swelling coefficient. When CO_2 is in the gas phase, the oil swelling coefficient rises with rising pressure. Higher pressure causes CO_2 to transition from the gaseous to the liquid state, reducing its solubility and the pressure's impact on the oil swelling factor. Since CO_2 solubility decreases as temperature rises, the influence of temperature demonstrates that a greater temperature causes a lower oil swelling factor in the low-pressure area. In the area of higher pressure, the swelling of the oil is larger than at low temperatures, because of the phase transition, which lowers the solubility of CO_2. Lighter oil can have a larger oil swelling factor than heavier oil despite having a different oil composition since more CO_2 could be dissolved into the lighter oil (Sayegh & Maini, 1984).

2.1.2.3 Effect of Diffusion Coefficient

Another significant parameter affecting the properties of the heavy oil- CO_2 system is the diffusion coefficient, which specifies the diffusion rate and the volume of CO_2 dissolved in heavy oil. Previous research suggests that the transitory zone, where heavy oil is saturated with an injected solvent and the area of the transient zone is regulated by the molecular diffusion rate of the injected solvent, is the primary source of heavy oil extraction in the vapor-extraction process (Ghasemi et al., 2017). When CO_2 is added to a heavy oil formation as a form of solvent, it progressively dissolves into the heavy oil by molecular diffusion, particularly during the soaking stage (Tharanivasan et al., 2004). As a result, the viscosity of the oil is reduced and it swells, increasing the production of heavy oil. According to Figure 4, the diffusion coefficient depends on the temperature, pressure, and composition of the oil.

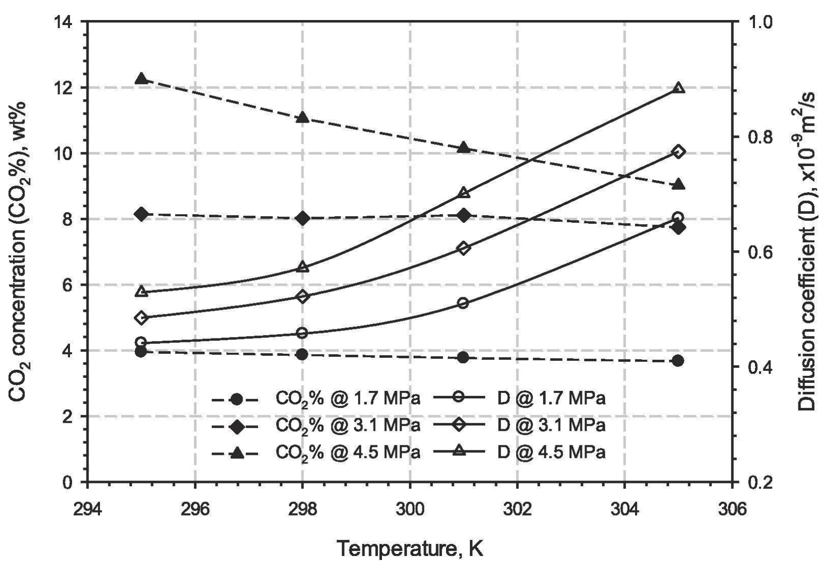


Figure 4. Diffusion coefficient and CO_2 solubility at various pressures and temperatures.

At higher temperatures than at lower temperatures, the diffusion coefficient is more sensitive to the impact of pressure since higher temperatures allow for the lower surface tension of oil molecules, which increases the rate at which CO_2 molecules move into heavy oil. Also, at a greater temperature, heavy oil viscosity is reduced, and CO_2 molecules may more easily cross the surface. Kavousi et al. (2014) investigated the diffusion rate of CO_2 in heavy oil at various pressures and temperatures. In their scientific studies, the diffusion coefficient of CO_2 rises with rising pressure. However, if the pressure keeps rising to a high level, the density and viscosity of the heavy oil- CO_2 system also rises, resulting in a constant decrease in the diffusion ratio (Jamialahmadi et al., 2006). At a steady temperature, the diffusion coefficient rises with rising pressure in an area of relatively lower pressure, primarily because the higher pressure maintains a more driving force for the transfer of CO_2 into heavy oil. The cumulative effects of temperature and pressure demonstrate that when the temperature and pressure rise, the diffusion coefficient of CO_2 in heavy oil also rises. Since the diffusion coefficient of CO_2 in heavy oil drops as heavy oil viscosity rises, it may be inferred that the viscosity of heavy oil reduces as the temperature rises. According to Zhou et al. (2020), the diffusion coefficient of CO_2 in different heavy oil varies from 10^{-10} to 10^{-9} m^2/s. The reason why higher temperature and pressure result in an increased diffusion coefficient is due to the presence of more light or medium components in this heavy oil. Thus, the CO_2 diffusion coefficient is larger with higher API gravity, allowing the injected CO_2 to dissolve into the heavy oil more readily. Additionally, a comparatively lower viscosity might result in a greater CO_2 diffusion coefficient due to an increased CO_2 mass transfer rate. (Tharanivasan, 2006). When it comes to CO_2 solubility in heavy oil, solubility rises with pressure and falls with temperature, but there is no discernible correlation with the CO_2 diffusion coefficient.

2.1.3 Operational Issues of CO_2 huff 'n' puff

Through extensive use in heavy oil fields across the globe, CO_2 has been shown to be a successful option for recovering heavy oil in a narrow pay zone and low-pressure fields using the immiscible displacement technique (Mohammed-Singh & Ashok, 2005). The CO_2 huff 'n puff procedure has been used in the field for many years, but there are still technical and financial obstacles to be overcome when using it. Viscous fingering, corrosion, asphaltene precipitation, etc., are the primary significant issues. The two main financial barriers are the cost of CO_2

emission mitigation and oil pricing. The deposition of asphaltenes during the CO_2 huff ‘n’ puff leads to significant problems, such as formation damage, a reduction of relative permeability, and an interruption of flow in the formation. This can result in poor productivity and indeed no flow when the wellbore and pipes are plugged (Zanganeh et al., 2012). Additionally, when the asphaltene percentage is greater than 4.6%, the field's wettability will change between being water- and oil-wet, which lowers the extraction of heavy oil (Al-Maamari & Buckley, 2000).

The heavy oil at the bottom hole experiences wax precipitation when the temperature drops and the wax then adhere to the wellbore, which reduces the flow rate (Luo et al., 2005). Optimizing the pressure depletion rate, so that the temperature around the wellbore could not be too much lowered and the rate of extraction of heavy oil would not be significantly impacted, is an effective way to reduce wax precipitation in the basin. Another way is to add a wax formation inhibitor to the formation.

The polymer inhibitor forms a hydrocarbon chain between the wax and wax inhibitor. Wax appearance time can be shortened because the chain's polar section prevents the wax from aggregating (Machado et al., 2001).

When the injected CO_2 encounters water, a corrosive fluid is produced, which causes the equipment to corrode. Chloride corrosion is a significant issue in this method, even though specific steel and chemical protection are applied. The simplest method for avoiding CO_2 acid corrosion is to employ corrosion-resistant materials on the surface of metal parts and to add inhibitor agents to the formation (Parker et al., 2009). Since the viscosity of CO_2 is significantly less than that of formation fluids, viscous fingering arises during the injection of CO_2 into the formation. The pumped CO_2 will flow through the high permeability region and bypass the region with lower permeability. The breakthrough near wells can happen during CO_2 gas injection in heterogeneous deposits (Yuan & Azaiez, 2014).

Various approaches may be used to eliminate the adverse effects of layers with high permeability between wells in various oil production zones. First, the packer may be used to isolate thin layers with high permeability in the borehole (Olenick et al., 1992). The packer is not appropriate for a thick layer, which indicates that there are significant quantities of heavy oil in this layer. Before using the CO_2 huff 'n puff technique, the high permeability layer could be separated from the formation by an injection of a gel solution with high viscosity. There are other problems such as pump issues, low injectivity, formation of ice plugs inside tubes, etc., which are significant challenges in the reservoir (Sahin et al., 2007).

From an economic perspective, the expenses for CO_2 capture and transportation, CO_2 injection system equipment, etc. are the primary contributions. The CO_2 huff 'n puff method can be successfully implemented on gas condensate reservoirs near heavy oil fields.

2.2 Review of simulation studies

2.2.1 Eagle Ford Shale Simulation Study

The Eagle Ford shale well with heavy oil was put into production for 526 days before being restarted receiving 167 barrels of nanoparticle treatment and 160 tonnes of CO2 in 11 cycles. (Zheng et al., 2020). Utilizing information from the pilot well, a simulation analysis was carried out using a fully connected geomechanically compositional fracturing and reservoir model. The findings of the pilot test unmistakably demonstrate that the oil rate significantly increases following the injection of the nanoparticle and CO_2. According to laboratory findings, nanoparticles can make rocks more preferentially water-wet and reduce the interfacial tension between water and oil, both of which are advantageous for oil production. According to the modelling studies, CO_2 injection alone improved oil recovery just little and forecasts lower oil recovery than actual field conditions.

Table 1. Reservoir properties

Porosity	15 %
Permeability	8.2 nD
Bottomhole Temperature	150 °F
Bottomhole Pressure	130 psig
API Oil Gravity	40 API

For this well's improved recovery treatment, 166.6 bbl of nanoparticle solution and 160 tonnes of CO_2 have been pumped across 11 stages of nanoparticle-alternating-gas technology (Zheng et al., 2020). To effectively distribute the treatment dosage throughout the horizontal lateral, the first 10 stages were pumped using a diverter. CO_2 was injected 11 times in one day and the injection of the treatment took less than 24 h, and the well was shut in for 5 days post-treatment (Zheng et al., 2020).

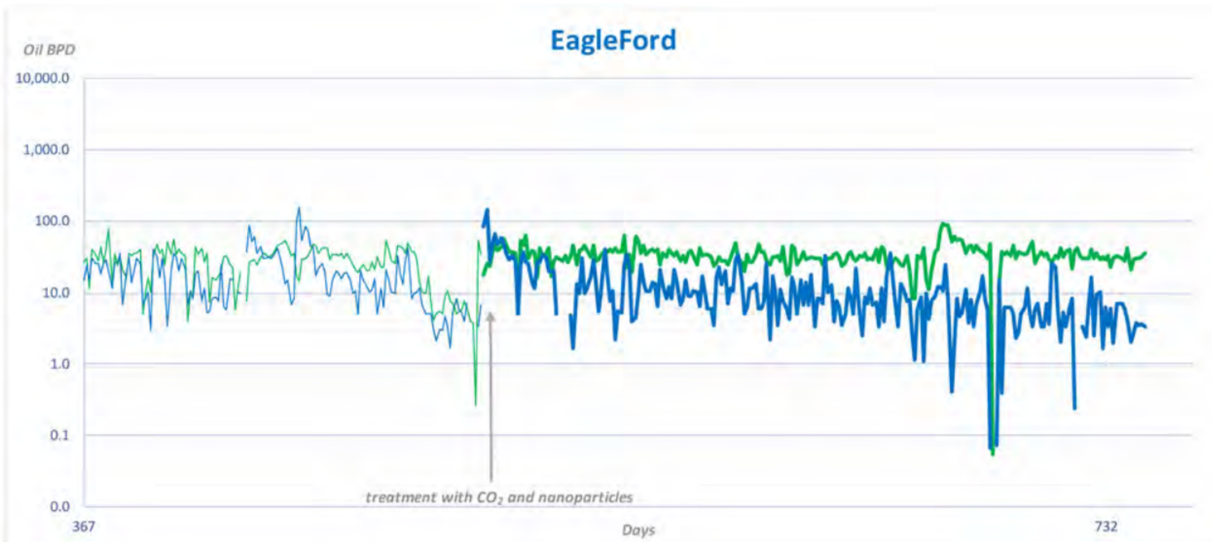


Figure 5. The water and oil production at Eagle Ford well. Thicker lines are for post-treatment

Figure 6. Cumulative oil production

Compared to the trend of the cumulative output based on the pre-treatment data, there are more than 5000 barrels of oil after treatment. The only noticeable effect of the diverter during the treatment stages was an increase in the daily output following treatment, which was a sign of when the diverter broke down. The average daily oil output for the thirty days before treatment was 17 barrels/day. The average daily oil output for the first 30 days after treatment was 34 barrels. The average barrel/day for the second 30-day post-treatment period was 37 (Zheng et al., 2020).

The simulated production from one fracture and its effective reservoir capacity is scaled up to the entire well. The pay zone was 134 feet high. The fracture fully penetrates the pay zone and is contained inside the pay zone since it has a half-length of 40 meters and a height of 40 meters5, respectively. It is believed that the top and lower boundary layers contain water. The reservoir lengths along the wellbore, along the fracture, and in the vertical direction in the sector model are 17.36 meters, 50 meters, and 100 meters, respectively, with an assumption of 50% cluster efficiency.

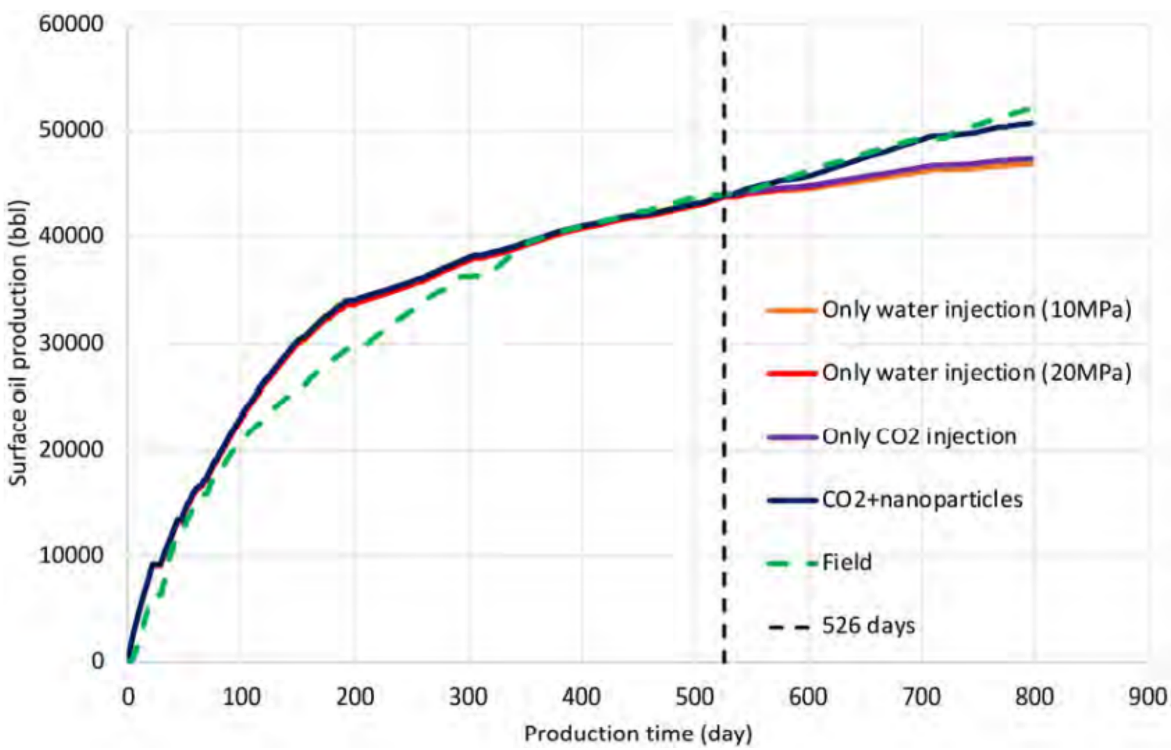


Figure 7. Cumulative surface oil production vs. Time

In the IOR phase, four situations were considered. The first three situations involve injecting CO_2 or water. Two water injection scenarios with maximum injection pressures set to 10 MPa and 20 MPa are conducted since the reservoir is highly tight and the water injection pressure exceeds the maximum injection pressure quickly. In the CO_2 injection scenario, 160 tonnes of CO_2 were pumped into the whole well at the estimated constant rate. The last scenario involves injecting both CO_2 and nanoparticle solutions. The third scenario's CO_2 injection rate is maintained, but the relative permeability curves are modified to reflect the beneficial effects of nanoparticles.

The pattern in oil production during the puff-and-puff is as follows: co-injection of CO_2 and nanoparticle solution > sole injection of CO_2 > sole injection of water. One can also see that the relative permeability curves must be raised for the simulated oil output following CO_2 and nanoparticle injection to match the field data. This suggests that the treatment is likely to enhance the relative permeability to oil. Greater oil recovery resulted from an increased CO_2 input. This oil rate in the pilot well is doubled by cyclical CO_2 and nanoparticle solution injection. The well's treatment with CO_2 and nanoparticle solution aids in maintaining a high oil rate as the water rate continues to fall. Larger CO_2 or lean gas injections are anticipated to significantly enhance oil recovery.

2.2.2 Simulation Study of M field in Indonesia

The Huff and Puff process is studied using hydrodynamic modelling and compositional simulation. By using the Peng-Robinson equation of state, fluid modelling for numerical simulation is carried out (Jeong & Lee, 2015). To characterize the pilot scale simulation, the reservoir around the target well, M-19, is removed. Regarding recovery factor, cumulative WOR, and GOR, the observations are evaluated with those from primary recovery. The purpose of the simulation is to evaluate how well the Huff and Puff procedure can increase oil recovery. To maximize the oil output, the Huff and Puff method is then tuned. Design factors for optimization are taken into consideration for operation circumstances such as injection rate and soaking duration (Jeong & Lee, 2015).

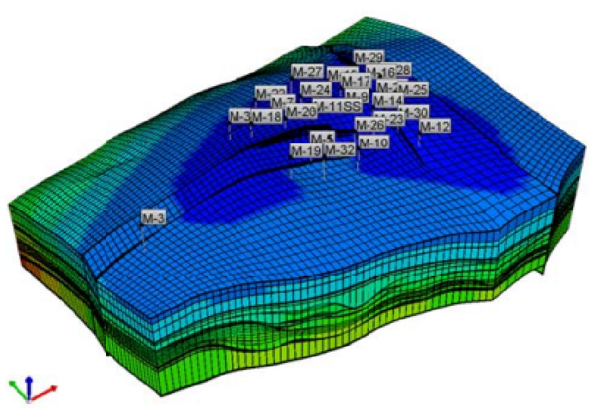


Figure 8. Reservoir model of M field

The target well, M-19, is located near a fault. The layer, in which the CO_2 is injected has a permeability of 120 to 1000 md (Jeong & Lee, 2015).

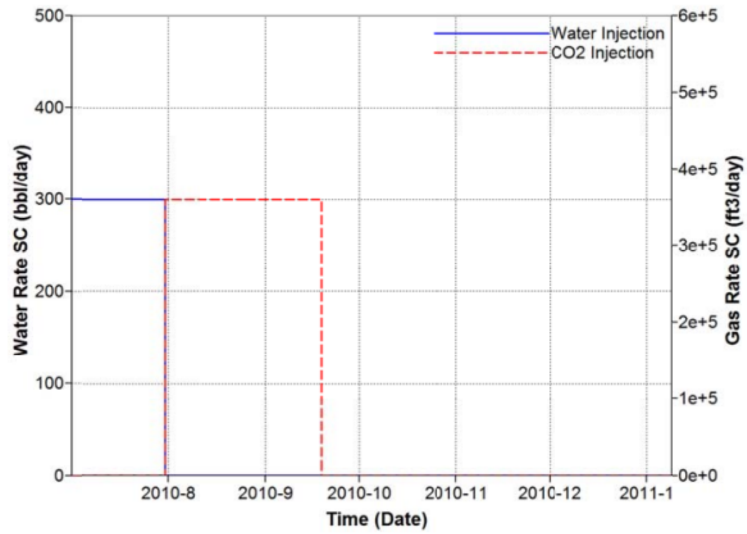


Figure 9. Water and gas rate vs. Time

Figure 9 represents the time for water and CO_2 injection. The rate of water injection was 300 bbl/d and was performed for 30 days (Jeong & Lee, 2015). Water is injected before the CO_2 injection to provide supplementary reservoir pressure. For the CO_2 case, the injection rate was 20 tons/D and the injection time was 50 days. The total amount of CO_2 injected was fixed to 1000 tons and the soaking time was set as 30 days. The minimum bottom hole pressure was set to 500 psi for the production well.

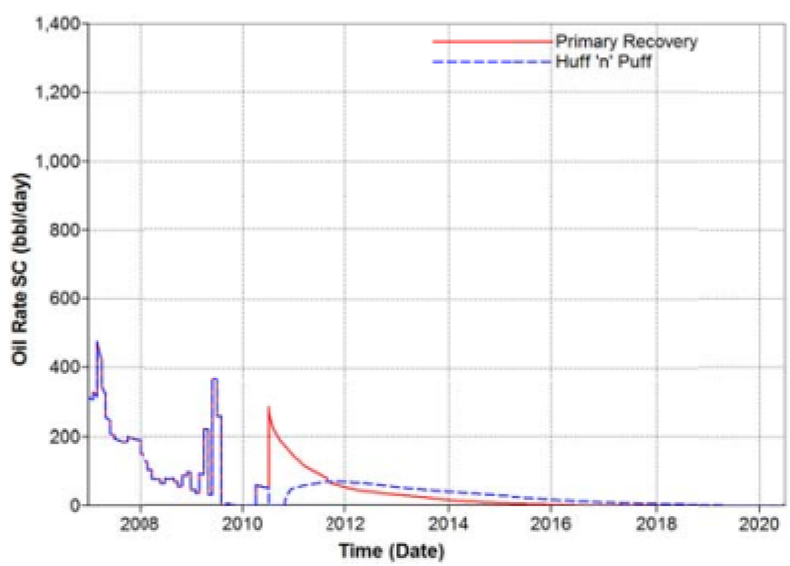


Figure 10. Primary recovery and for Huff 'n' Puff vs. Time

According to Figure 10, there is no advantage for the Huff 'n' Puff process over primary recovery at the early stages (Jeong & Lee, 2015). The reason for that can be the injection of water, which disturbs the oil flow. Water injection was performed to increase the reservoir pressure.

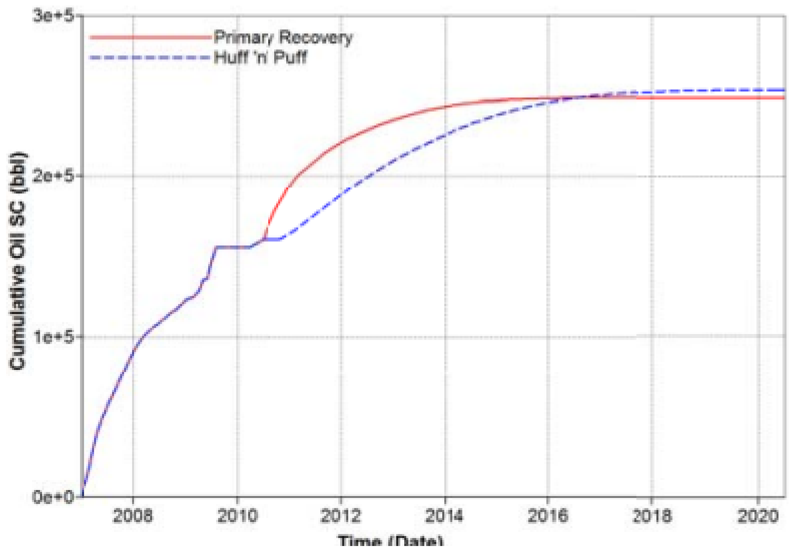


Figure 11. Cumulative oil vs. time

After the Huff and Puff method, the incremental cumulative oil recovery was increased by 2%. This trend can be seen in Figure 11 (Jeong & Lee, 2015). According to the findings, the GOR of the Huff and Puff method has increased by 33% (Jeong & Lee, 2015). The results from the simulation were found by the following parameters for the Huff and Puff method:

Table 2. Design parameters

Parameters	Value
CO2 Injection Rate	20 tons/D
CO2 Injectiom Time	50 days
Soaking time	30 days

After the base case, the optimum design case was conducted. The optimum parameters for the Huff and Puff method were as follows:

Table 3. Optimum design parameters

Parameters	Value
CO2 Injection Rate	30 tons/D
CO2 Injectiom Time	33 days
Soaking time	120 days

The optimum parameters were found by the CMG software. The result shows that for the optimum design, there should be higher water injection rate, longer soaking time and water injection time can increase the oil recovery.

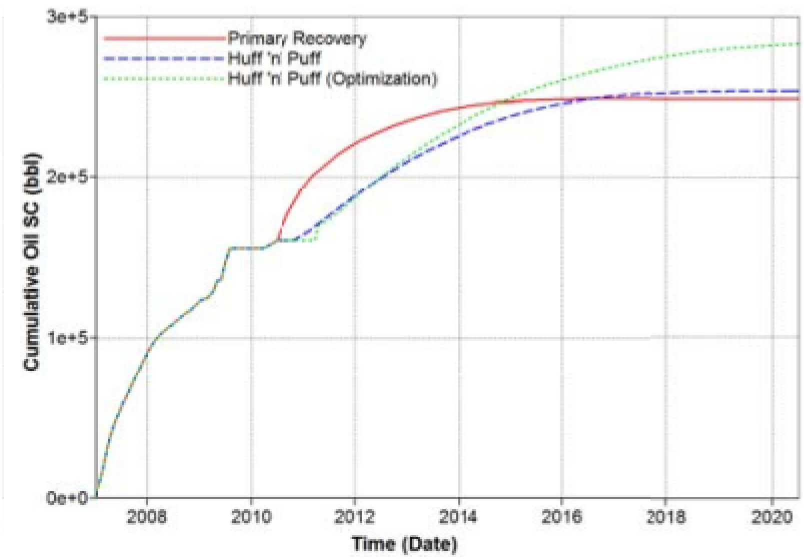


Figure 12. Cumulative oil for optimized case vs. time

For the optimum case, incremental oil recovery was increased by 12%. WOR increased by 10%, while GOR remained almost the same as in the base case.

To sum up, the Huff and Puff method provided 2% of incremental cumulative oil production. It can be explained by the reduction of viscosity and swelling effect. Another point is that reservoir CO_2 requires higher reservoir pressure and injection rate for the optimum case because the water injection rate is high and reservoir pressure blocks CO_2 to be injected. For the optimum case, the incremental oil recovery can reach to 12%, which shows that Huff and Puff method requires optimization to reach the maximum efficiency from the project.

2.3 Review of field cases

2.3.1 South Louisiana field in USA

The test well is situated in Bayou Mallet Field and completed in 4500 ft. This reservoir features a 17-foot oil zone and an 83-foot water zone. The well was produced on a pump at a rate of 17 BOPD and 160 BWPD before CO_2 injection, with around 23,000 STB oil production (Schenewerk et al., 1992). It is assumed that the high-water cut was due to water coning. Reservoir properties for the target area are indicated in table 4.

Table 4. Reservoir properties

Initial reservoir pressure, psia	2000
Reservoir pressure prior to test, psia	1300
Reservoir temperature,°F	148
Reservoir thickness, ft	100
Water saturation, %	40
Permeability, md	2000
Oil gravity, API	28
Gas oil ratio	nil
Initial oil production rate, BOPD	70
Oil production rate prior to test, BOPD	17
Water production rate prior to test, BWPD	160
Porosity, %	33

CO_2 was transported in 20 tons tank loads to the test well location and stored there in two 60 tons mobile storage containers. The injection was carried out using a machine for injecting CO_2 that was specifically created and controlled by Liquid Carbonic. A total of 120 tons at flow rates between 0.5 and 4.0 barrels per min of CO_2 were injected into the test well (Schenewerk et al., 1992). The range of wellhead pressure was between 1500 and 1900 psi during the injection stage. The wellhead-injected temperature ranged between 58F and 70F. The duration of the CO_2 injection was 6.6 h. After injection, the test well was shut-in for the soaking stage during which injected CO_2 diffused throughout the formation and interacted with the oil. After that, the production stage started after 28 days (Schenewerk et al., 1992). Initially, the test well-produced CO_2 and some hydrocarbons with greater molecular weight for three days, then the production stopped, and the well was put on the pump. As a result, the test well started to produce more by 15 STB oil and 5 bbl. water. It is obvious that the CO_2 injection has had a considerable effect on the fluid distribution around the wellbore.

2.3.2 Jiangsu Oilfield in China

70 CO_2 huff 'n' puff experiments were carried out in various Jiangsu oilfield wells from 1997 to 2004 (Yang & Xue, 2010). 49 tests revealed incremental oil. There were some failures in the implementation of cyclic CO_2 injection. A failure was due to mechanical issues with the CO_2 injection, while two were related to a clear excessive injection pressure brought on by poor reservoir characteristics (Yang & Xue, 2010). Each test was conducted in a sandstone reservoir that contained light oil (0.9 to 0.78 g/cm3). Selected reservoir characteristics for fields where CO_2 injection extracted more oil are summarized in Table 5.

Table 5. Reservoir characteristics

Field	Formation Thickness (m)	Average Permeability (md)	Average Porosity (%)	Depth (m)	Average Temperature (℃)	Average Pressure (MPa)
CZ	18.8 to 29.2	40.7	15	2712 to 3186	95	27.3
FM	5.5 to 59.8	160.4	19.7	2181 to 3201	88	23.6
LMZ	7.3	31	14	2566.5	83.1	24.6
SN	3.9 to 32.2	64.1	23	2128 to 2422	83	11.7
ZZ	4.4	186.2	22	1898	56	19
XJZ	8.6 to 17.9	35	15	2947 to 3068	89	27.7
XZ	22.5	3.8	20	2315	-	15.5
ZW	2.2 to 33.2	321	23	2036 to 3160	80	22.2

The 70 tests' conditions are shown in Table 6. Test methods differed for the more successful initiatives. Typically, liquid CO_2 was carried in tanker trucks. A corrosion inhibitor was commonly used to displace injected CO_2 from the wellbore. Throughout the soak time, the test well's tubing and casing pressures were observed. The favored method for reopening wells includes the deployment of a tiny choke to boost backpressure on the well and decrease CO_2 breakout and production isolation to prevent surface operations from being negatively impacted by CO_2. To prevent premature CO_2 energy depletion and to allow for additional CO2/oil interaction.

Table 6. Test Conditions Summary

Field	Number of Tests	CO_2 slug Size (tons)*	Soak (days)	Incremental Oil (tons)
CZ	6	176 to 264	21 to 33	38 to 698.4
FM	15	24 to 735	20 to 32	100 to 1599
LMZ	1	100	25	58.1
SN	13	24 to 200	28 to 64	38.3 to 397.7
ZZ	1	99	22	0
XJZ	11	53 to 304	15 to 38	124.2 to 393.8
XZ	1	171	22	0
ZW	22	80 to 360	15 to 40	56.7 to 523.2

Note: * measured at conditions of 12℃ and 6.1 MPa

It can be seen from Table 6 that with the effective use of the CO2 huff and puff process, an increase in oil extraction was observed in relation to the mass of injected CO2. Due to CO_2 dissolving in the oil and removing damage to the area around the wellbore, CO_2 injection appears to increase well productivity. The amount of CO_2 injected significantly correlated with the production response. Figure 13 illustrates how incremental oil recovery rose as the amount of CO_2 injected increased.

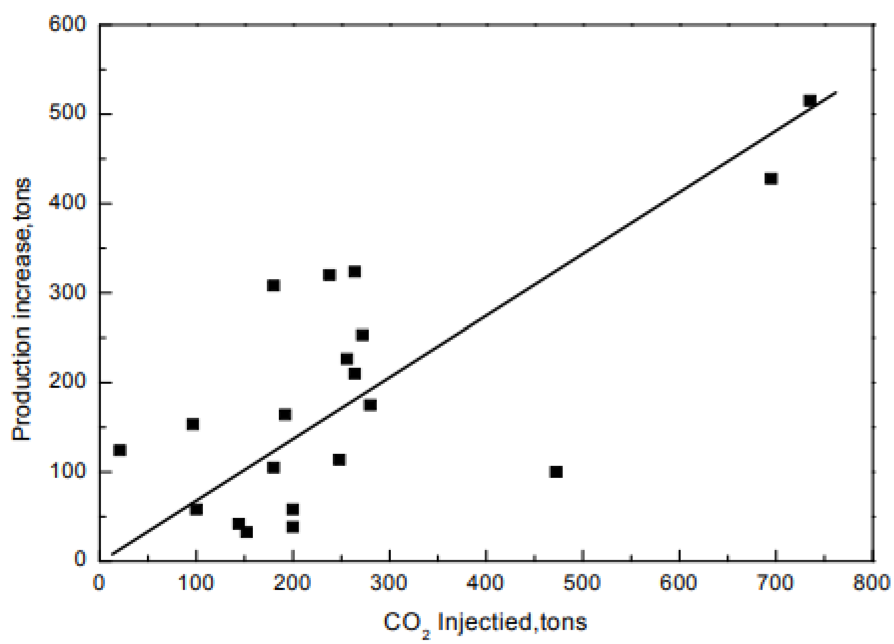


Figure 13. Injected CO_2 mass vs. Incremental oil

Figure 14 illustrates a considerable increase in incremental oil production in 2 and 3 cycles for wells. Apparently, these wells have improved from the elimination of damage near the wellbore and pressurization (Yang & Xue, 2010).

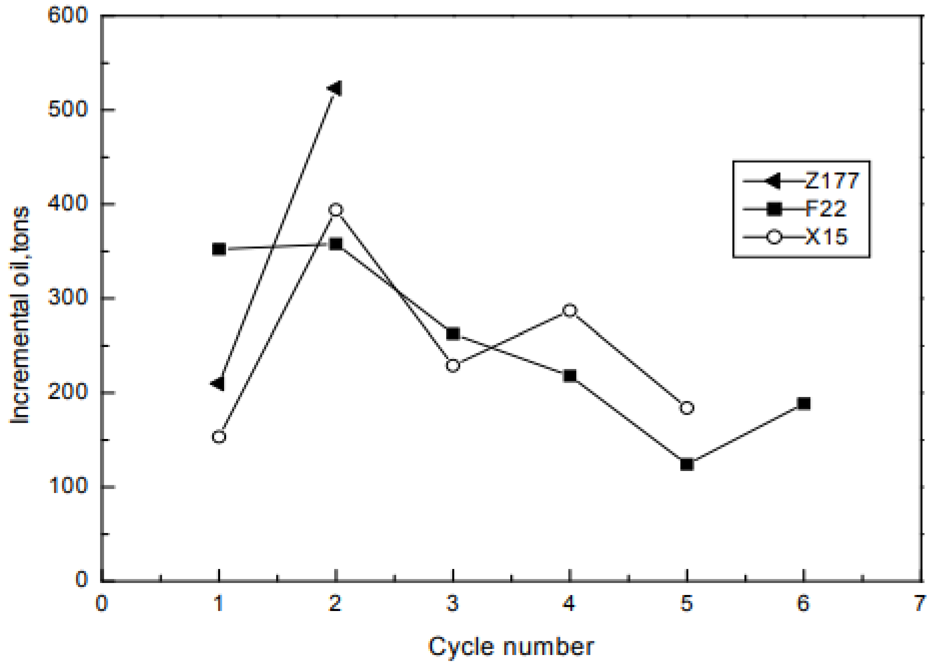


Figure 14. Incremental oil vs. Cycle number

Although all had soak durations between 15 and 40 days, there was no influence of soak time on oil recovery (Yang & Xue, 2010).

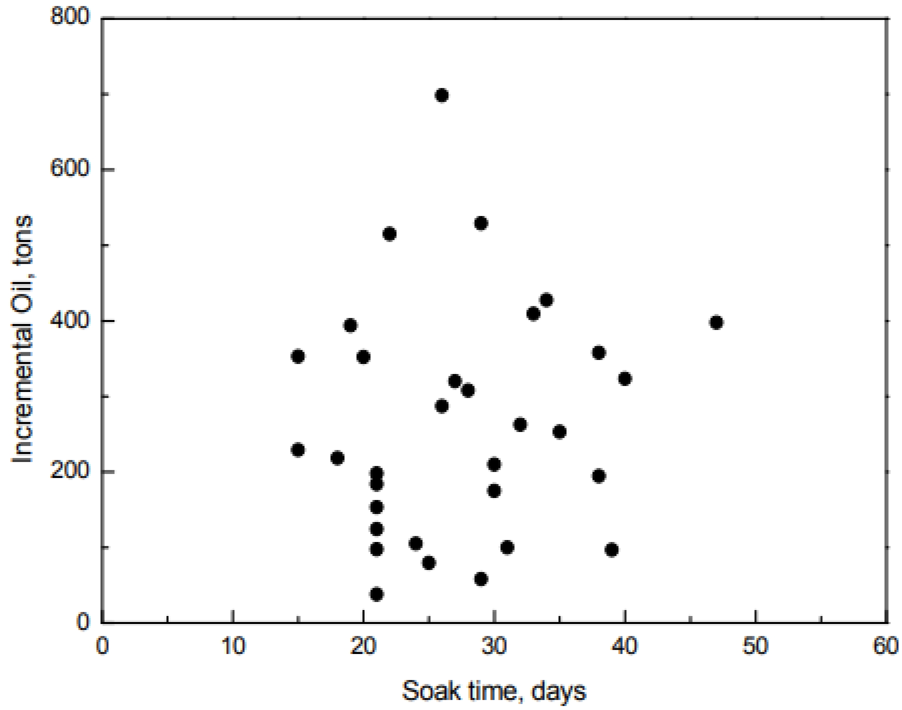


Figure 15. Incremental oil vs. Soaking times

To sum up, reversing production damage and enhancing oil swelling with the use of gravity drainage are thought to be the important factors boosting oil recovery in the Jiangsu reservoir with light crude oils (Yang & Xue, 2010).

2.4 Summary

Zhou et al. (2018) mentioned that the CO_2 huff 'n' puff method is divided into three stages: the injection stage, the soaking stage, and the production stage. In the injection stage, CO_2 is injected into the target formation by a production well. In the soaking stage, a production well that was injected with CO_2 is shut down for a certain amount of time and oil swelling and viscosity reduction occur due to CO_2 diffusion inside the reservoir. In the production stage, the well is opened, and oil production begins. This technique contributes to an increase in oil production from the reservoir due to oil swelling, a decrease in viscosity, a decrease of interfacial tension and changes in relative permeability due to the displacement of mobile water by CO_2. Unfortunately, this method has operational issues and financial obstacles. Viscosity fingering, corrosion, and asphaltene precipitation. are major concerns. The two main financial barriers are the cost of reducing CO_2 emissions and the price of oil (Zanganeh et al., 2012).

Two simulation studies and field cases were reviewed. The Eagle Ford Shale was chosen for the first simulation study. 160 tons of CO_2 over 11 cycles in one day were injected inside the well and the injection of the treatment took less than 24 hours; the well was shut in for 5 days after the treatment (Zheng et al., 2020). The average daily oil production rate for thirty days before processing was 17 barrels per day. The average daily oil production rate for the first 30 days after processing was 34 barrels. The average bbl./d during the second 30-day post-treatment period was 37 bbl./d.

The second simulation study was the M field in Indonesia. Target well M-19 is located near a fault. The formation into which CO_2 is injected has a permeability of 120 to 1000 mD. The CO2 injection rate was 20 tons/day, and the injection time was 50 days. The soaking time was 30 days. For the production well, the bottom hole pressure was set at 500 psi. Additional cumulative oil production increased by 2%.

The South Louisiana field in the USA was chosen for the first field case. A total of 120 tons of CO_2 was injected into the test well at a rate of 0.5 to 4.0 bpm (Schenewerk et al., 1992). Wellhead pressure ranged from 1500 to 1900 psi during the injection stage. The injection temperature at the wellhead ranged from 58F to 70F. The duration of the CO_2 injection was 6.6 h.. As a result, the test well produced 15 barrels of oil and 5 barrels of water.

The second field case was the Jiangsu oilfield in China. 70 experiments with CO_2 emissions were conducted at various wells of the Jiangsu oil field from 1997 to 2004 (Yang and Xue, 2010). There were some failures due to mechanical issues in the implementation of cyclic CO_2 injection. The size of the CO_2 plug ranged from 24 to 735 tons. The range of cyclic numbers was from 1 to 6. Soaking time ranged from 15 to 64 days. The incremental oil ranged between 0 to 1599 tons. The elimination of production damage and increased swelling of oil using gravity drainage are considered important factors that increase oil recovery in Jiangsu reservoir light oil (Yang and Xue, 2010).

Based on simulation studies and field cases, CO_2 injection rate is the most crucial factor, followed by CO_2 injection pressure, time, and number of cycles.

3 Methodology

3.1 Simulation model

This simulation research examines the effect of varying operational parameters of CO_2 injection by the huff-n-puff process on oil production using the CMG-STARS simulator. A 103.3-acre cartesian grid scheme was used to generate the reservoir simulation. Sensitivity analysis on three cases was used to investigate the impact on oil production. These cases involved different injection rates, cycles, and time of soaking of the well. The same inverted one-spot well pattern, which will be both a production well and an injector well, is present in each scenario. For this well, data on the trajectory of the well and perforation are given.

3.1.1 Reservoir grid model

The geometry of the reservoir was selected to be rectangular a system of cartesian grids. There were 1000 grid blocks in all, which is equivalent to a rectangular-shaped reservoir with 20 grid blocks in the "x" direction, 10 grid blocks in the "y" direction and 5 grid blocks in the "z" direction. The width of the block in the "x" and "y" directions is 150 feet. The area of the reservoir was 103.3 acres. Figure 16 depicts the position of the injection and production wells and a grid design. The reservoir shape was adopted in each case with a few small variations in reservoir characteristics and CO_2 injection conditions.

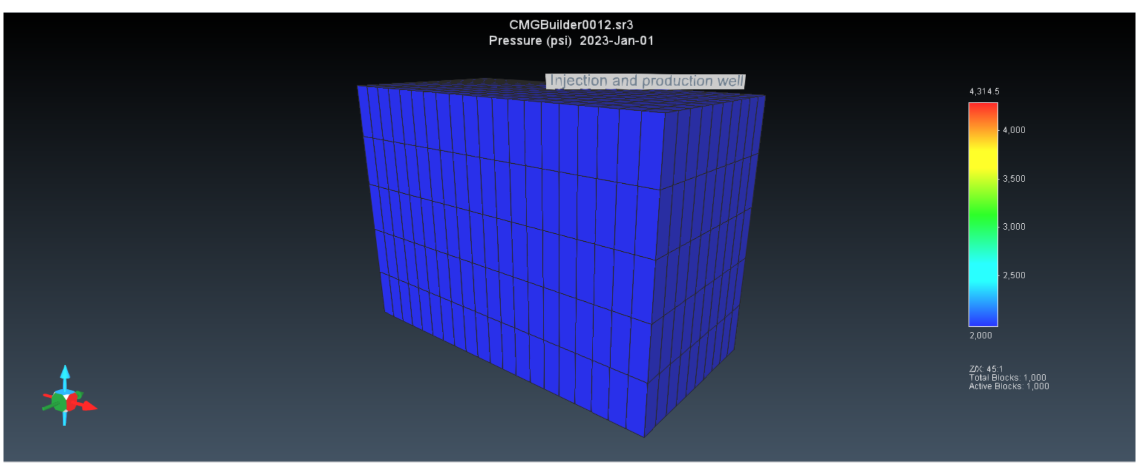
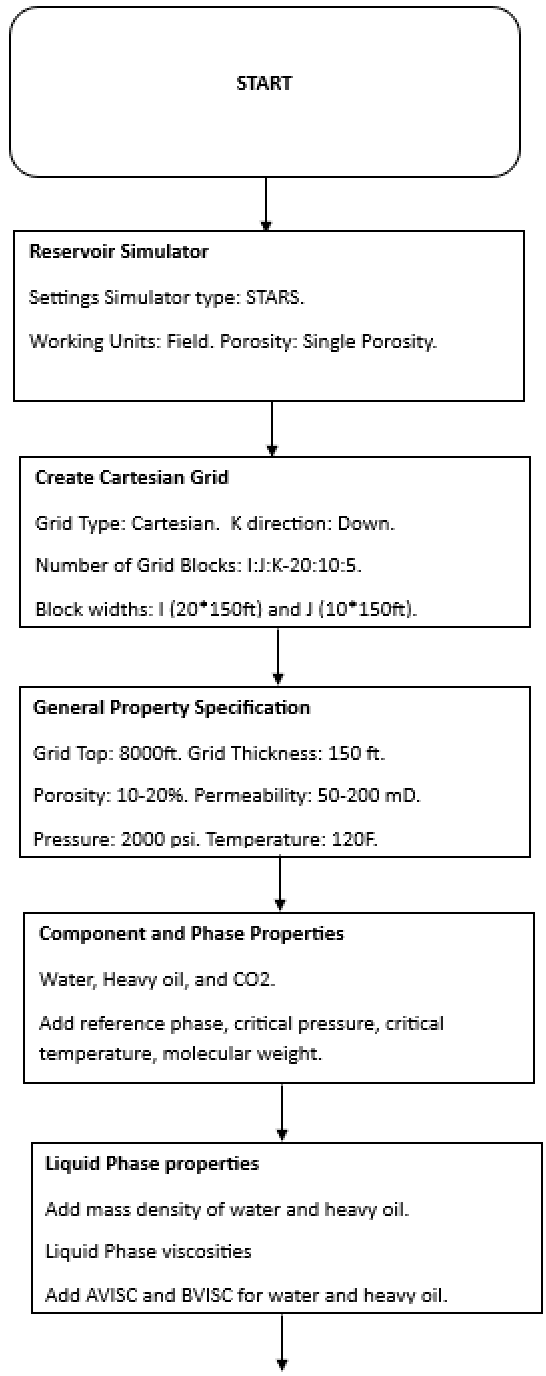


Figure 16. Location of producer and injection well

Table 7 contains the reservoir parameters, which were applied in each simulated scenario. Three sandstone reservoirs were created with different ranges of porosity and permeability. The first sandstone reservoir has a poor quality porosity of 10% and a permeability of 50md. The second reservoir has a fair-quality porosity of 15% and a permeability of 100md. The third reservoir has a good quality porosity of 20% and a permeability of 200md. The range for porosity and permeability are taken from carbonate-porosity-sandstone vs carbonate paper.

Table 7. Reservoir rock parameters (CMG template, 2018)

Variable	Number
Reservoir depth, m	2438.4
Reservoir area, ac	103.3
Reservoir thickness, m	150
Porosity, %	10-20
Permeability, mD	50-200
Reservoir pressure, kPa	2000
Reservoir temperature, °F	120


START
Reservoir Simulator
Settings Simulator type: STARS.
Working Units: Field. Porosity: Single Porosity.
Create Cartesian Grid
Grid Type: Cartesian. K direction: Down.
Number of Grid Blocks: I:J:K-20:10:5.
Block widths: I (20*150ft) and J (10*150ft).
General Property Specification
Grid Top: 8000ft. Grid Thickness: 150 ft.
Porosity: 10-20%. Permeability: 50-200 mD.
Pressure: 2000 psi. Temperature: 120F.
Component and Phase Properties
Water, Heavy oil, and CO2.
Add reference phase, critical pressure, critical temperature, molecular weight.
Liquid Phase properties
Add mass density of water and heavy oil.
Liquid Phase viscosities
Add AVISC and BVISC for water and heavy oil.

Add relative permeability correlations.

Reference pressure (PRSR): 14.7 psi

Reference temperature (TEMR): 120 F

Surface conditions pressure (PSURF): 14.7 psi

Initial Conditions

Do not perform Vertical Equilibrium Calculations (Vertical Off).

First Time Step Size after Well Change (DTWELL):**0.001**.

Isothermal Option (ISOTHERMAL): **ON.**

Model Formulation (TFORM): **ZT**

Linear Solver Irritations (ITERMAX): **150**

Linear Solver Orthogonalizations (NORTH): **150**

Maximum Average Scaled Residual for All Equations: **Tight**

Create New Well

Name: Injector

Type: Injector Mobweight implicit

Add max STG surface gas rate.

Add max BHP bottom hole pressure.

Injected fluid: CO_2

Mole fraction of CO_2: 1.0

Name: Producer

Type: Producer

Add min BHP bottom hole pressure.

Well Completion Data (Perf)

Add perforated grid blocks for producer and injector.

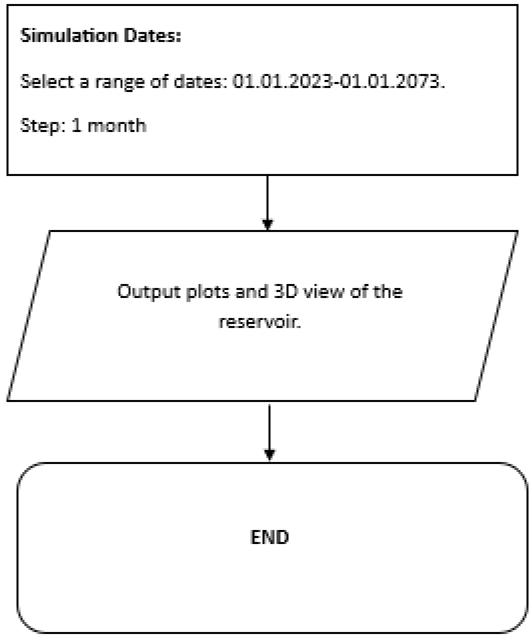


Figure 17. Flowchart for creating the reservoir by using CMG-STARS

The flowchart in Figure 17 illustrates the process of creating a reservoir using CMG-STARS.

3.1.2 Fluid component data

The liquid component segment includes data on oil, water, and injected CO_2. The CMG-STARS data package was used to provide all the fluid parameters. Table 8 indicates the key fluid parameters. Standard water characteristics of 1cp viscosity and 990 kg/m^3 density was used.

Table 8. Fluid parameter for CO_2 (CMG template, 2018)

Parameters	CO_2
Specific gravity	0.3
Boiling point, C	-161.5
Critical pressure, atm	45
Critical volume, m3/kg mol	0.099
Critical temperature, K	190.6
Molecular weight, g/mole	16

The fluid parameter for heavy oil is taken from Huff 'n' puff Experimental Studies of CO_2 with Heavy Oil article (Shilov, 2019).

Table 9. Fluid parameter for heavy oil

Parameters	Heavy oil
Density at 20 ℃ (kg/m^3)	931.0
Viscosity at 25 ℃ (mPa s)	421.8
Compressibility ($1/MPa$)	$6.29 * 10^{-4}$
Molecular weight ($g\ mol^{-1}$)	499.51

Table 10 shows the Water-Oil Table. Water-Oil Table and Liquid-Gas Table (liquid Saturation) are obtained from used as input to reservoir simulation models. Figures 18 and 19 show how much water, oil, and gas are flowing relative to each other.

Table 10. Water-Oil Table

S_w	k_{rw}	k_{row}
0.250	0.000	0.900
0.283	0.001	0.741
0.316	0.004	0.603
0.349	0.010	0.483

0.382	0.018	0.380
0.415	0.029	0.292
0.448	0.042	0.220
0.481	0.057	0.160
0.515	0.075	0.112
0.548	0.094	0.075
0.548	0.117	0.047
0.614	0.141	0.027
0.647	0.168	0.014
0.680	0.198	0.006
0.713	0.229	0.002
0.746	0.263	0.001
0.780	0.300	0.000

The diagram of the relative permeability curve of oil-water in a water-wet reservoir is shown below. In water-wet rock, a layer of water covers the surface of the rock and acts as a lubricant for oil placed in the middle parts of the pores. As can be seen from Figure 18, as water saturation increases oil relative permeability decreases and water relative permeability increases until attaining residual oil saturation. Rock wettability is strongly water wet. When the water saturation level is below the irreducible water saturation point, water does not flow through the medium, and its relative permeability is zero. Figure 19 shows Liquid-Gas Table. When the liquid saturation increases gas relative permeability decreases and oil relative permeability increases. Residual oil saturation and connate water plus residual oil saturation are shown in FIgure 19.

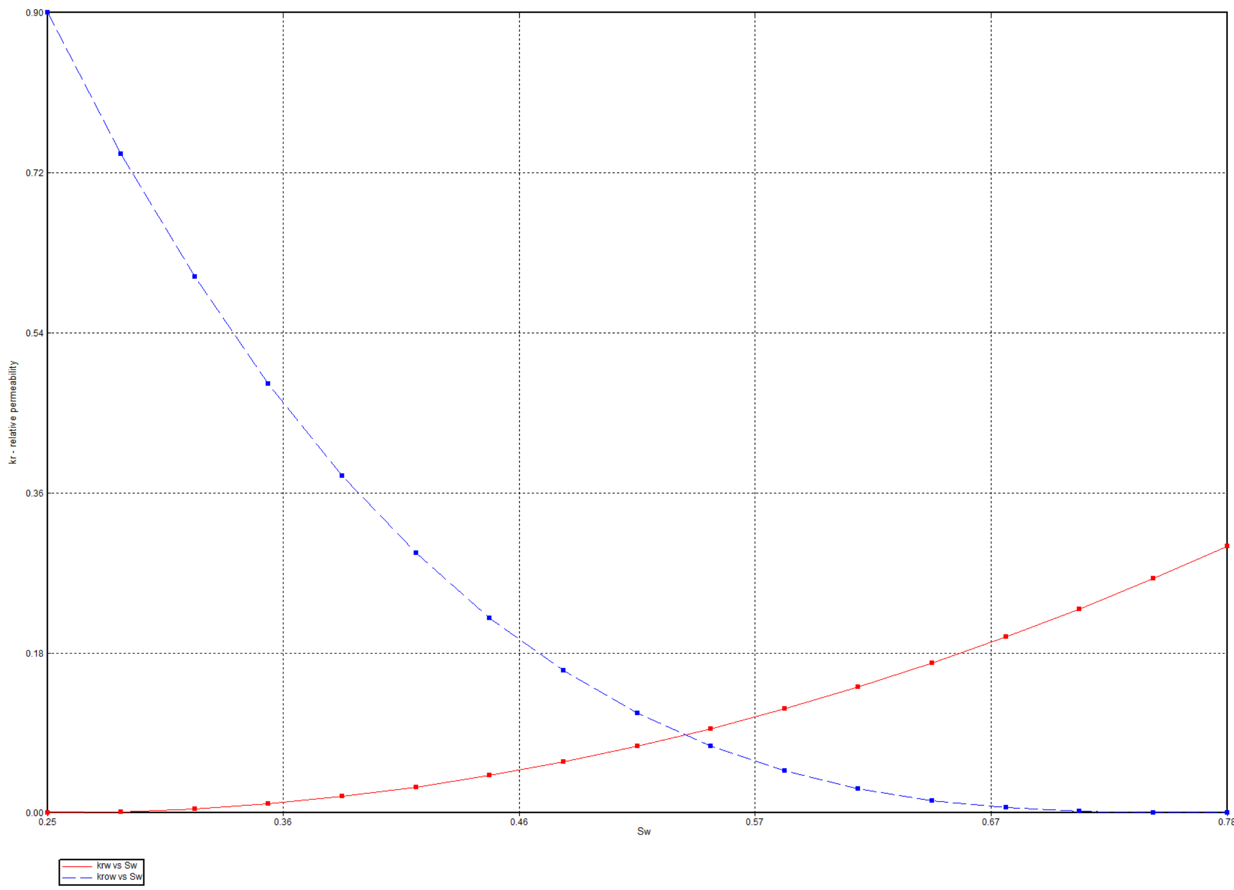


Figure 18. Krg vs. Sw and Krow vs. Sw

Table 11. Liquid-Gas Table (liquid Saturation)

Sl	k_{rg}	k_{rog}
0.550	0.300	0.000
0.575	0.247	0.001
0.600	0.161	0.001
0.625	0.126	0.004
0.650	0.097	0.010
0.675	0.073	0.019
0.700	0.053	0.033
0.725	0.037	0.052
0.750	0.075	0.080

0.775	0.025	0.113
0.800	0.015	0.154
0.825	0.009	0.205
0.850	0.005	0.266
0.875	0.002	0.339
0.900	0.001	0.423
0.925	0.000	0.520
0.950	0.000	0.632
0.975	0.000	0.758
1.000	0.000	0.900

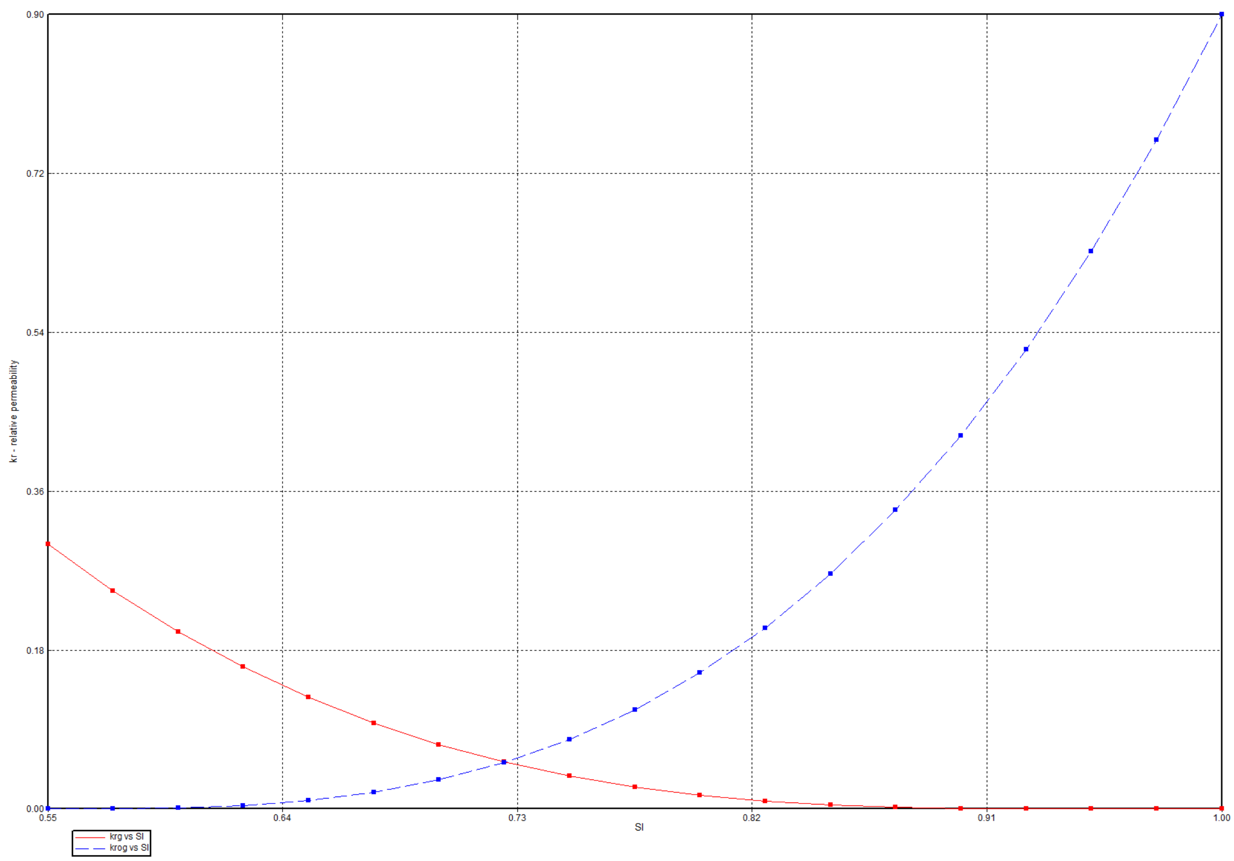


Figure 19. Krg vs. SI and Krog vs.SI

Table 12 and Table 13 show the component data and surface conditions pressure and temperature.

Table 12. Component Data

#	Aqueous	Oleic	Gaseous	PCrit, psi	TCrit, F	MW, lb/lbmole
1	Reference phase		K-value partitioned	3197.79	705.56	18.015
2		Reference phase		0	0	449.51
3			Reference phase	1069.8	87.89	44.01

Table 13. Surface conditions pressure and temperature

Description	Default	Value
Reference Pressure(PRSR)	14.5038 psi	14.7 psi
Reference Temperature (TEMR)	77 F	120 F
Surface conditions pressure (PSURF)	14.6488 psi	14.7 psi
Surface conditions temperature (TSURF)	62.33 F	

3.1.3 Rock properties data

For rock properties, it is important to consider capillary pressures, relative permeabilities, and rock compressibility. For the simulation in the CMG software, some governing equations need to be mentioned. Rock wettability is Water Wet. Stone's Second model was used for evaluating 2-Phase KRO.

3.1.3.1 Capillary pressure

Any contact between any two immiscible fluids experiences a discontinuity in fluid pressure in a two-phase flow (e.g., water and oil). The interfacial tension that exists at the interface is the cause of this. The capillary pressure, pc, is the difference between the pressures in the wetting and nonwetting phases, such as oil and water, respectively:

$$p_c = p_o - p_w \tag{1}$$

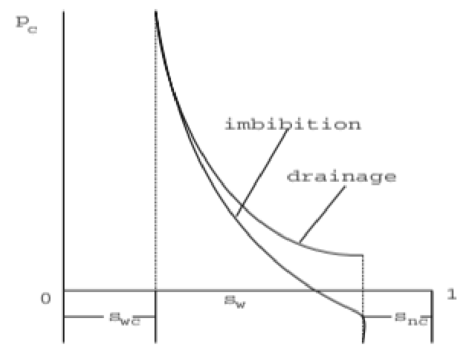


Figure 20. Capillary pressure curve

The wetting phase saturation S_w and the direction of the saturation shift (drainage or imbibition) determine the capillary pressure.

3.1.3.2 Relative permeability

Relative permeabilities are significantly influenced by the rock's wettability as well. The curves themselves cannot be used to identify the saturation value at which the displaced phase becomes immobile because the slopes of capillary pressure curves at irresidual saturations must be finite in numerical simulation. Differentiating between the critical and residual saturations is not essential. For any specific porous material of interest, relative permeabilities must be established empirically or experimentally.

3.1.3.3 Rock compressibility

Rock compressibility is defined as

$$c_R = \frac{1}{\phi}\frac{d\phi}{dp} \quad (2)$$

After integration, the equation becomes:

$$\phi = \phi^o e^{c_R(p-p^o)} \quad (3)$$

where ϕ^o is the porosity at a reference pressure p^o. After Taylor series expansion and approximation, the equation results:

$$\phi \approx \phi^o(1 + c_R(p - p^o)) \quad (4)$$

The data for rock properties are set as the default in the CMG software. These default values are used to examine the effect of CO_2 injection by the Huff and Puff method and focus on sensitivity analysis, in which the changing parameters will be Injection Rate, Injection Pressure, Injection Period, and Soaking Period.

3.1.4 **Well data**

The goal of the simulation research was to forecast a rise in oil recovery from the CO_2 Huff-n-Puff process during the next 50 years. One well as the injector and producer were used in each case with constant operating constraints. The first constraint was used to control the maximum allowable flow rate, which ranged from 30 to 80 tons per day depending on the case. The minimum bottom hole pressure was set at 4300 psi for the flow rate control and 1800 psi for the production well. Well list shut and open are shown in the Figure 21.

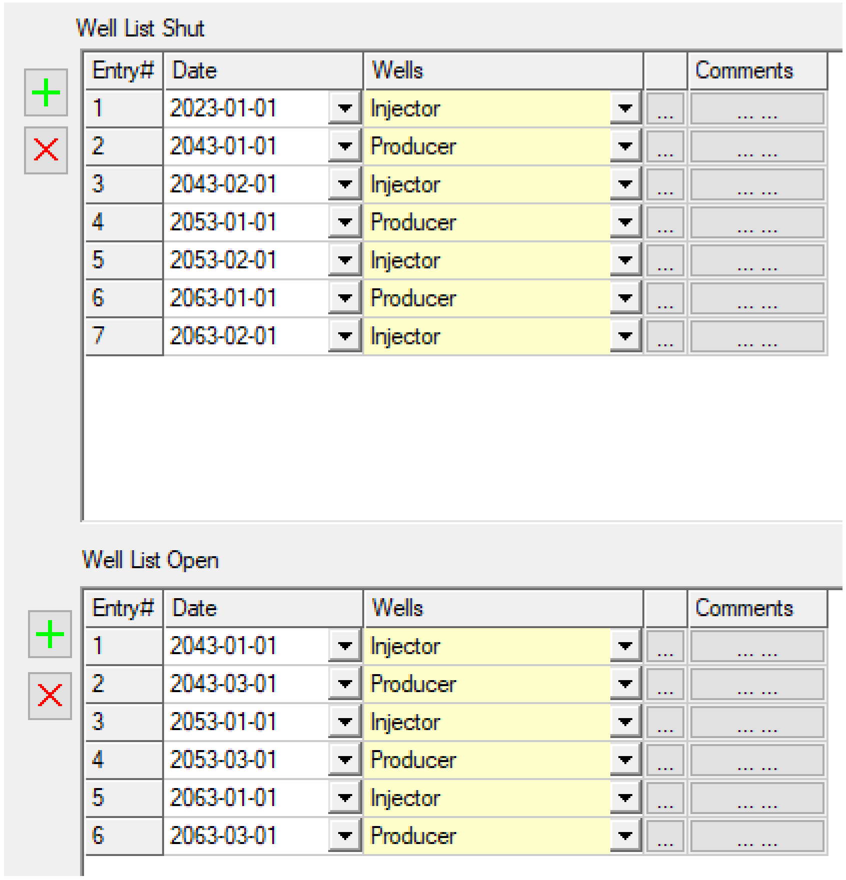


Figure 21. Well List Shut and Open

3.1.5 **Fluid flow through reservoir**

The governing equations for a single fluid flow in reservoir simulation are the mass balance equation, the Darcy equation, and the equation of state. The mass balance equation describes the conservation of mass in the reservoir, while the Darcy equation describes the flow of fluid through the reservoir. The equation of state describes the relationship between pressure, temperature, and volume of the fluid. Since no mass of this fluid may traverse the fluid-solid interface, we assume that the mass fluxes caused by dispersion and diffusion are insignificant and that the fluid-solid interface is a material surface with respect to the fluid mass.

By deriving mass inflow and outflow equations, we obtain the mass conservation equation:

$$\frac{\partial(\phi\rho)}{\partial t} = -\nabla\cdot(\rho u) + q \tag{5}$$

where ρu is mass flux and q is a sink of strength. While, $\nabla\cdot$ is a divergence operator. This equation is going to be utilized in the reservoir simulation study.

Additionally, to the mass conservation equation, we must state momentum conservation in the form of Darcy's law. According to this rule, the fluid velocity and pressure head gradient have a linear connection:

$$u = -\frac{1}{\mu}k(\nabla p - \rho\wp\nabla z) \tag{6}$$

where k is the absolute permeability tensor of the porous medium, μ is the viscosity of the fluid, $\wp$ is the gravitational acceleration magnitude, z is the depth and ∇ is the gradient operator. The ability of the porous medium to transport fluid is measured by the average medium attribute known as permeability. Sometimes, it is possible to assume that permeability is a diagonal tensor, in which if in diag(k_{11},k_{22},k_{33}), k_{11}=k_{22}=k_{33}, the porous medium is isotropic; otherwise, it is anisotropic.

The equation of state is expressed by fluid compressibility c_f:

$$c_f = -\frac{1}{V}\frac{\partial V}{\partial p}\Big|_T = \frac{1}{\rho}\frac{\partial \rho}{\partial p}\Big|_T \tag{7}$$

where V is for the occupied volume by the fluid at reservoir conditions, and T is for fixed temperature. By combining the equation of state and momentum conservation, we get a closed system for the main unknown p or ρ.

The boundary and initial conditions must be stated in order for the mathematical model for single-phase flow to be complete. We use to designate the porous medium domain Ω under consideration's external border or a boundary segment Γ.

When the pressure is defined as a known function of position and time on, the boundary condition is

$$p = g_1 \text{ on } \Gamma \tag{8}$$

Such a condition is known as a boundary condition of the first kind, or a Dirichlet boundary condition, in the theory of partial differential equations. When the total mass flux is defined as a known function on Γ, the boundary condition is

$$pu \cdot \nu = g_2 \text{ on } \Gamma \tag{9}$$

where ν is outward unit normal to Γ. Boundary conditions of the second sort, or Neumann boundary conditions, are what this circumstance is known as. Next, the mixed boundary condition is

$$g_p p + g_u \rho u \cdot \nu = g_3 \text{ on } \Gamma \tag{10}$$

where g_1, g_2, g_3 are given functions. A boundary condition is also known as a Robin or Dankwerts condition. In the case of Γ being a semi-pervious border, such a condition exists.

We are frequently interested in the simultaneous flow of two or more fluid phases through a porous material in reservoir modelling. We consider two-phase flows in which there is no mass that transfer between the phases and the fluids are immiscible. The wetting phase is the one that moistens the porous material more than the drying phase (for example, oil). Water is the wetting fluid in comparison to oil and gas, while oil is the wetting fluid in comparison to gas. It is necessary to incorporate several new parameters specific to multiphase flow, including relative permeability, capillary pressure, and saturation in the governing equations.

3.1.6 **Simulation case scenarios**

Case 1: Effect of cycles

Three types of reservoirs with different porosity in the range of 10-20% and permeability of 100-200 mD were used in this case study. The total period of oil production was 50 years. The primary depletion period occurred after 20 years of continuous oil production. The reservoir pressure during the primary depletion period was 1800 psi. After the depletion period, CO_2 gas is pumped continuously at a rate of 52.6 tons per day for 1 month. The injection flow rate is controlled by a bottom hole pressure of 4300 psi. The soaking period was 1 month. The difference between cycles was 10 years since the next depletion period requires a minimum of 10 years. The number of cycles was 3 for each reservoir. The cumulative liquid production and recovery factors for each reservoir were calculated. The optimal number of cycles for each formation was determined using a sensitivity analysis.

Case 2: Effect of Injection Rate

The study was conducted on a reservoir with 20% porosity and permeability 200 md. Three different CO_2 injection rates were used, namely 30 tons per day, 52.6 tons per day, and 80 tons per day. The incremental oil recovery and cumulative oil production were measured and compared for each injection rate. The appropriate injection rate was determined for a simulated reservoir by sensitivity analysis.

Case 3: Effect of Soaking Period

The simulation was performed on a reservoir with a porosity 20% and a permeability of 200 md. Various soaking periods ranging from 0 to 60 days were carried out to analyze the effect of the soaking period. The oil recovery factor and total production of liquid for different soaking periods were measured and compared. The most profitable soaking period was identified by a sensitivity analysis.

4 Results and Discussion

The operational factors related to CO_2 injection are investigated in this chapter, including the effects of the injection cycle, injection rate, and soaking period. The incremental oil production, gas injection, and incremental recovery factor were simulated and compared with 3 different case studies. The matrix for the simulation is presented in Table 14.

Table 14. The matrix for simulation

Case No.	Reservoir porosity/ permeability	CO_2 Injection cycles	CO_2 Injection rate	Soaking time
1	10%/50 md, 15%/100 md, 20%/200 md	0, 1, 2, 3 cycles	52.6 tons/day	1 month
2	20%/200 md	3 cycles	30 tons/day, 52.6 tons/day, 80 tons/day	1 month
3	20%/200 md	3 cycles	80 tons/day	0, 1 month, 2 months

4.1 Effect of Cycles

The aim of this section was to investigate the impact of cycles on oil production and recovery factors. Three rock properties were selected, from low to high porosity/permeability. For each scenario, one to three cycles of CO_2 huff and puff injection were simulated. The average CO_2 injection rate was fixed at 52.6 tons/day.

4.1.1 Effect of cycles on 10% porosity and 50 md permeability reservoir

The simulation results are presented in Figures 22, 23 and 24 and summarized in Table 15. The results of the study show that the CO_2 Huff and Puff method impacts oil production and recovery factor. The original oil-in-place of an oil reservoir was 182.04 MSTB. If only the internal pressure of the reservoir is applied, the incremental oil recovery was 6.53%. However, the cumulative oil production increased to 24.51 MSTB.

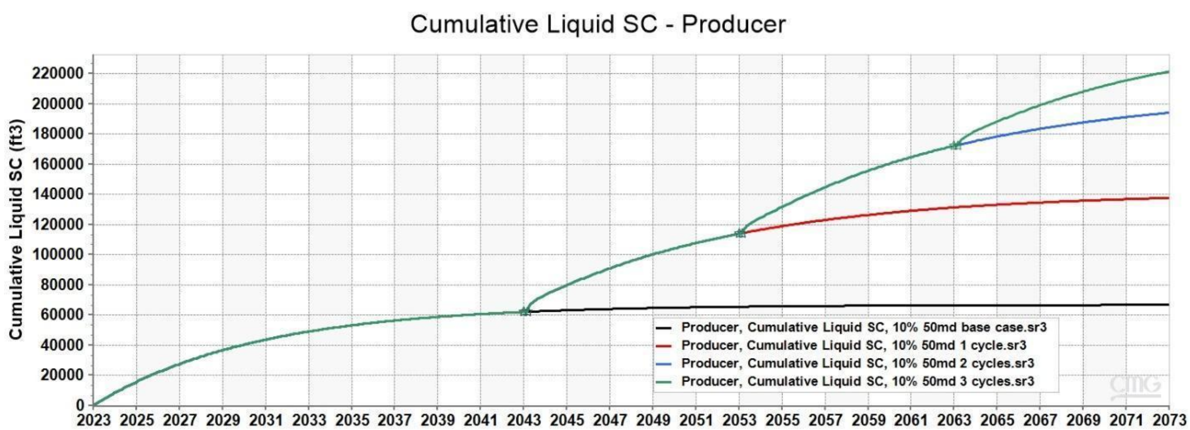


Figure 22. Cumulative liquid production (10% porosity, 50 md permeability) vs. Time

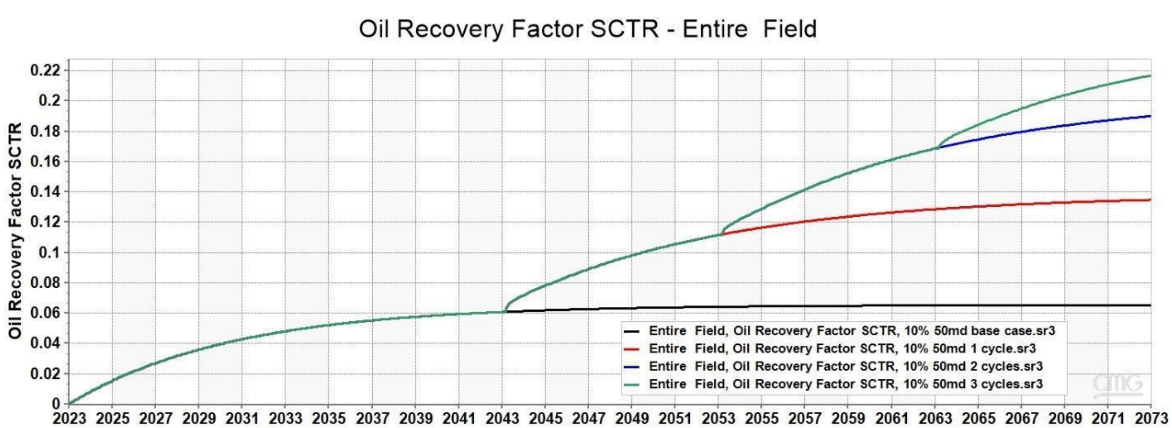


Figure 23. Oil recovery factor (10% porosity, 50 md permeability) vs. Time

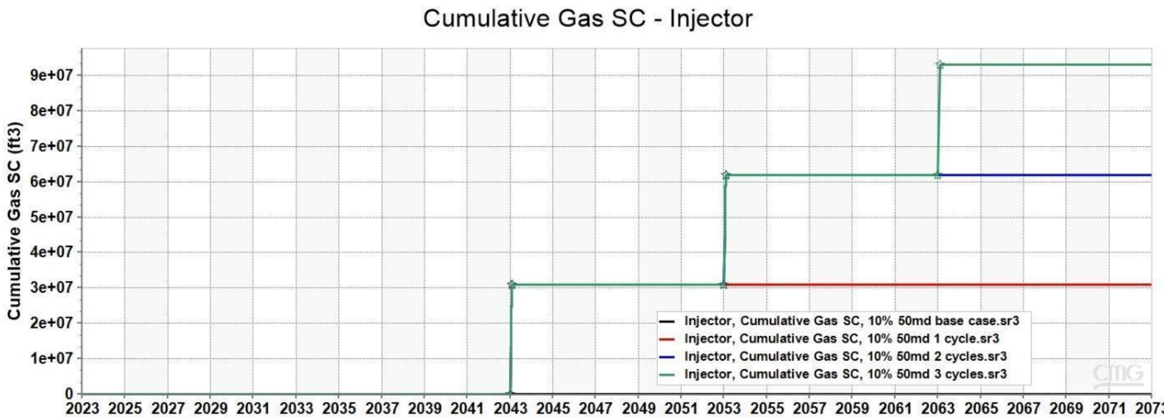


Figure 24. Cumulative CO_2 gas injection (10% porosity, 50 md permeability) vs. Time

Table 15. Summary for a reservoir with a porosity of 10% and permeability of 50 md

10% porosity, 50 md	Base case	1 cycle	2 cycles	3 cycles
Injected CO_2, tons	0	1578	3156	6312
Cumulative oil produced, MSTB	11.89	24.51	34.57	39.43
Oil recovery factor, %	6.53	13.47	19.00	21.68
Oil/ CO_2 Ratio	0	0.0022	0.0018	0.0009

After one cycle of CO_2 huff and puff injection. After two cycles, the cumulative oil production reached 34.57 MSTB, and after three cycles, this production rose to 39.43 MSTB. The incremental oil recovery increased from 6.53% after one cycle to 13.47%, after two cycles to 19.00% and 21.68% after three cycles. After the first and second cycles, the incremental oil recovery grew by about 6%, but in the third cycle, it rose by less than 3%. Additionally, the ratio of oil and CO_2 is approximately the same for the 1st and 2nd cycles, and the 3rd cycle is twice less compared to the 2nd cycle. The application of three cycles will not be efficient for increasing oil extraction, since with increasing cycles, the incremental oil recovery will still grow slightly. Therefore, we can conclude that implementing the two cycles of the CO_2 huff-n-puff technique is an efficient solution for increasing oil production for a reservoir with a porosity of 10% and a permeability of 50 md.

4.1.2 Effect of cycles on 15% porosity and 100 md permeability reservoir

The simulation results are shown in Figures 25, 26 and 27 and detailed outputs are contained in Table 16. For the second scenario, the porosity and permeability of the formation were raised to 15% and 100md. The initial oil-in-place of the deposit increased by about 89.05 MSTB and reached 272.95 MSTB with an increase in the porosity of the oil field. Hence, the rock's capacity to accumulate oil and gas increases with the increasing porosity of the oil field. The mobility of oil inside the reservoir improved when the permeability was increased, thereby the rate of oil production also grew. Incremental oil recovery was 6.54% without implementing secondary and tertiary recoveries.

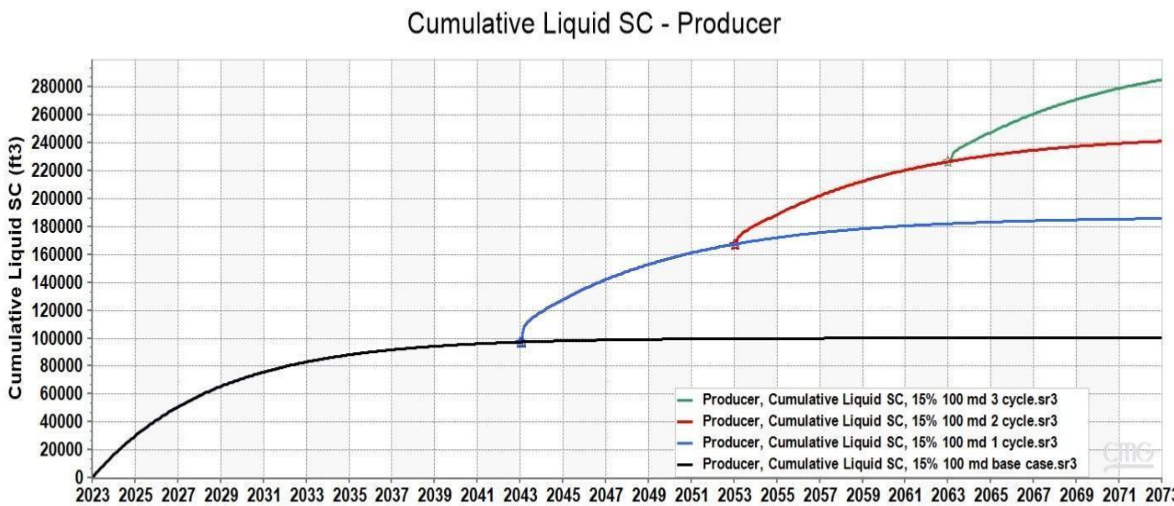


Figure 25. Cumulative liquid production (15% porosity, 100md permeability) vs. Time

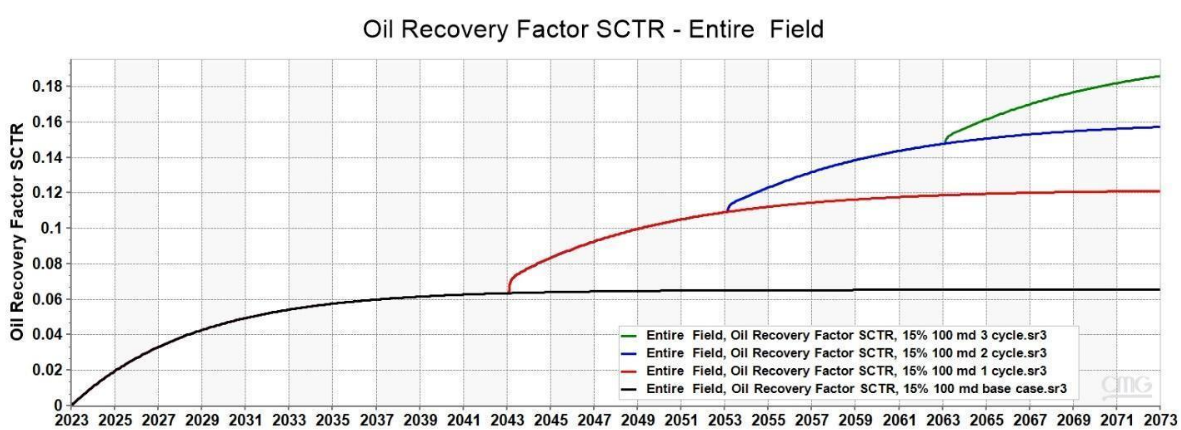


Figure 26. Oil recovery factor (15% porosity, 100md permeability) vs. Time

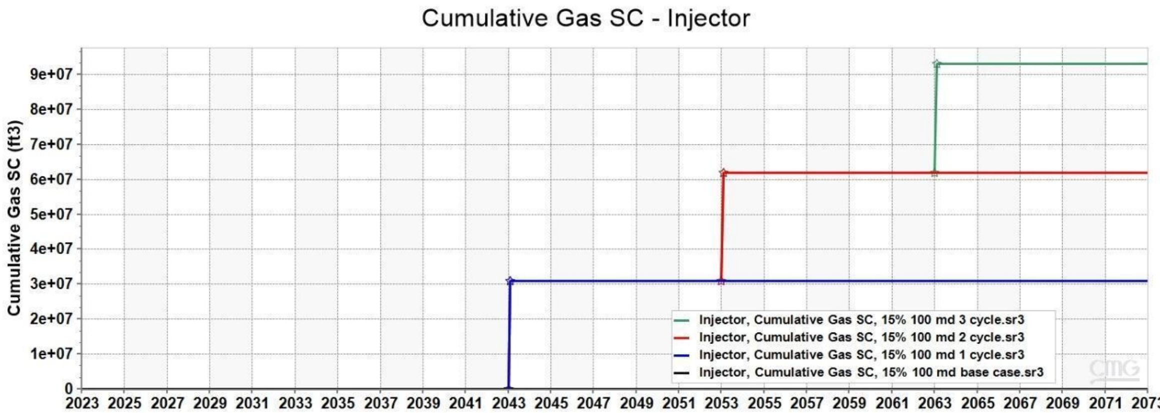


Figure 27. Cumulative CO_2 gas injection (15% porosity, 100md permeability) vs. Time

Table 16. Summary for a reservoir with a porosity of 15% and permeability of 100 md

15% porosity, 100 md	Base case	1 cycle	2 cycles	3 cycles
Injected CO_2, tons	0	1578	3156	6312
Cumulative oil produced, MSTB	17.85	33.10	42.98	50.83
Oil recovery factor, %	6.54	12.11	15.72	18.6
Oil/ CO_2 Ratio	0	0.0027	0.0018	0.0014

After the one cycle of the CO_2 huff-n-puff method, the percentage of oil recovery increased approximately twice and reached up to 33.104 MSTB. When the second and third CO_2 injection cycles were applied, oil recovery grew by 3% each time and reached up to 18.6%. The ratio of extracted oil and injected CO_2 gas decreased with increasing cycles. The difference between the second and third cycles is negligible in terms of the ratio of produced oil and pumped CO_2 gas, but they are smaller compared to the first cycle. However, three cycles in the reservoir are significantly more than the three cycles in the previous reservoir in terms of the ratio of extracted oil and injected CO_2 gas. Therefore, the profitable option would be to apply three cycles of the CO_2 huff-n-puff injection method since there will be no significant growth in cumulative oil production during the application of the fourth cycle.

4.1.3 Effect of cycles on 20% porosity and 200 md permeability reservoir

The simulation result is illustrated in Figure 28, and the detailed data obtained are presented in Table 17. For the third scenario, the porosity and permeability of the reservoir increased to 20% and 200md. The initial oil-in-place of the reservoir was 363.99 MSTB. The cumulative oil extraction increased to 39.07 MSTB. After one cycle of CO_2 huff and puff injection. After two cycles, the cumulative oil extraction reached 50.64 MSTB, and after three cycles, this production rose to 60.72 MSTB. The incremental oil recovery was 6.54% during the primary production.

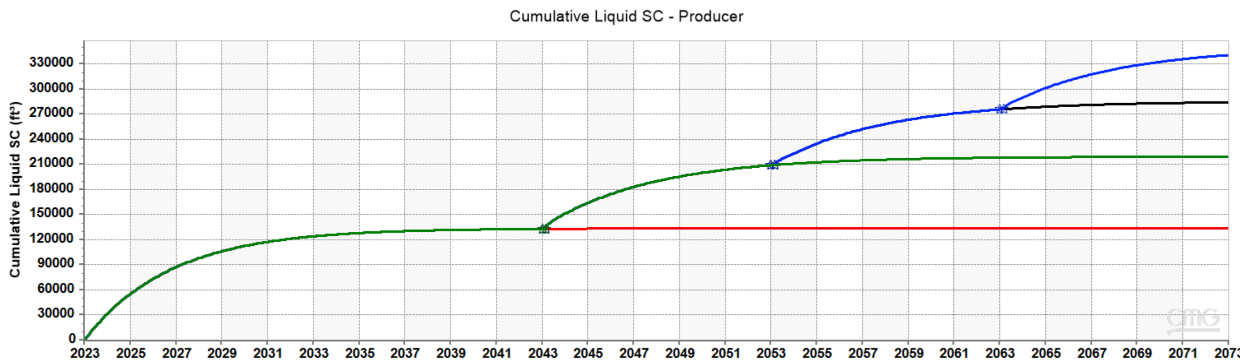


Figure 28. Cumulative liquid production (20% porosity, 200md permeability) vs. Time

Table 17. Summary for a reservoir with a porosity of 20% and permeability of 200 md

20% porosity, 200 md	Base case	1 cycle	2 cycles	3 cycles
Injected CO_2, tons	0	1578	3156	6312
Cumulative oil produced, MSTB	23.80	39.06	50.64	60.71
Oil recovery factor, %	6.54	10.73	13.91	16.68
Oil/ CO_2 Ratio	0	0.0027	0.0021	0.0017

The difference in the ratio of extracted oil and injected CO_2 gas is small compared to previous reservoirs. The percentage of oil recovery after the first cycle was lower than in reservoirs with lower permeability and porosity. This percentage increased by roughly 3% after each cycle. However, the incremental oil recovery is considerably small compared to previous oil fields. Therefore, the CO_2 huff-n-puff technique is less effective for reservoirs with high permeabilities and porosities. There will not be a substantial increase in incremental oil recovery during the implementation of the fourth cycle, and it would be beneficial to apply only three cycles for this scenario.

4.1.4 General discussion

For all three scenarios, the cumulative oil production and oil recovery rose as the injection cycles increased. The best effect of using the CO_2 huff and puff method can be noticed in the first scenario with 10% porosity and 50 md of permeability. The results show that it has the highest incremental oil recovery compared to the other two scenarios with increased porosity and permeability. By increasing the number of cycles in the CO_2 huff and puff method, the oil production and recovery factor can increase because it allows for more efficient use of the injected CO_2. During the injection phase, the CO_2 helps reduce the viscosity of the oil and pushes it towards the production well. However, not all of the injected CO_2 is immediately consumed during this phase, and some of it can remain trapped in the reservoir. During the shut-in period, the trapped CO_2 can dissolve more oil and continue to reduce the viscosity of the remaining oil. When the injection phase resumes, the trapped CO_2 can be mobilized and pushed towards the production well, resulting in increased oil production. Another reason can be that the injection of CO_2 increases the pressure within the reservoir, leading to the displacement of additional oil. As the number of cycles increases, the pressure within the reservoir continues to rise, leading to the greater displacement of oil and hence, an increase in oil production and recovery factor. By increasing the number of cycles, the amount of trapped CO_2 that can dissolve additional oil increases, which in turn can lead to higher oil production and recovery factors. However, the optimal number of cycles will depend on the specific reservoir conditions and characteristics, and the economics of the EOR project will need to be carefully evaluated to determine its viability. It is important to note that in three case scenarios, the porosity and permeability of the reservoir increase. Initial oil-in-place also increases with increasing reservoir porosity. Increasing reservoir porosity and permeability can have a counterintuitive effect on the incremental oil recovery using the CO_2 huff and puff method. For a reservoir with high porosity and high permeability, the injected CO_2 only affects the pay zone near the wellbore, without entering a deep reservoir. This means the injected CO_2 cannot effectively interact with crude oil in deep formation, leading to relatively low oil recovery. In addition, when the porosity and permeability of a reservoir are increased, the pore structure of the rock formation changes, reducing the capillary forces that hold the oil in place. This can result in a more rapid release of oil from the reservoir, making it easier to produce without the need for the CO_2 huff and puff method or using another EOR method if the RF is too small. However, all the scenarios followed the same trend when the effect of cycles were investigated. Three types of reservoirs had the same primary oil recovery due to the constraint of the bottom hole pressure of the production well. The pressure should not be below 1800 psi for all reservoirs.

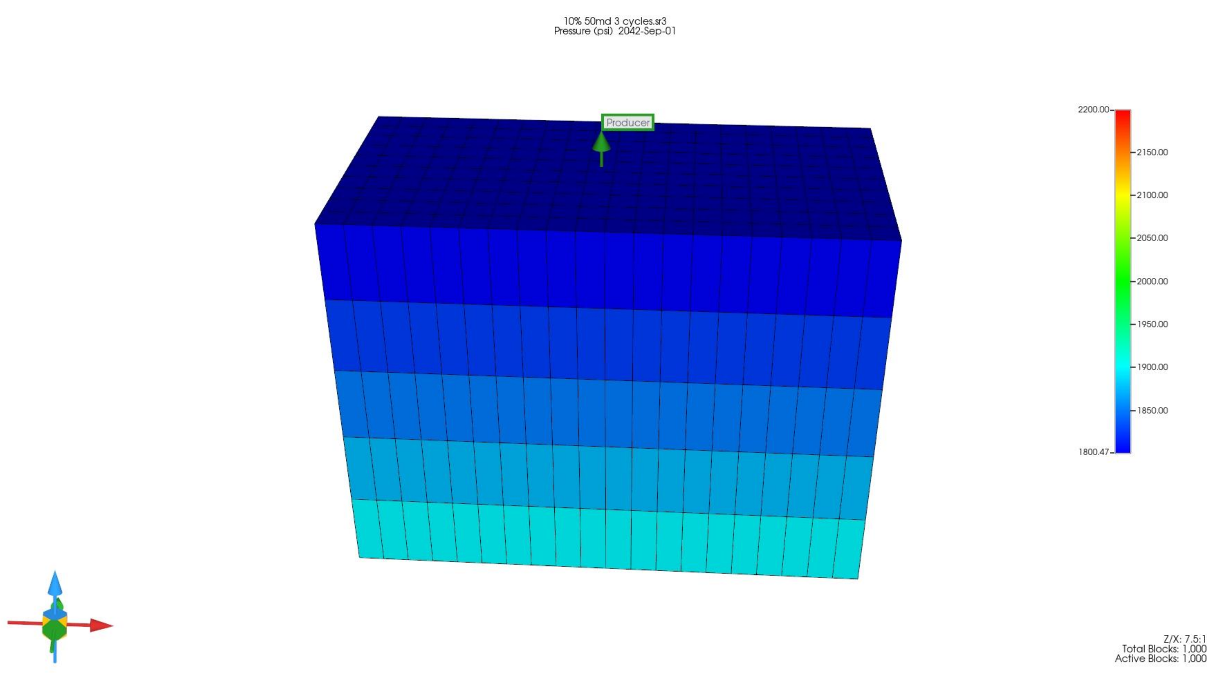


Figure 29. Reservoir pressure at primary depletion.

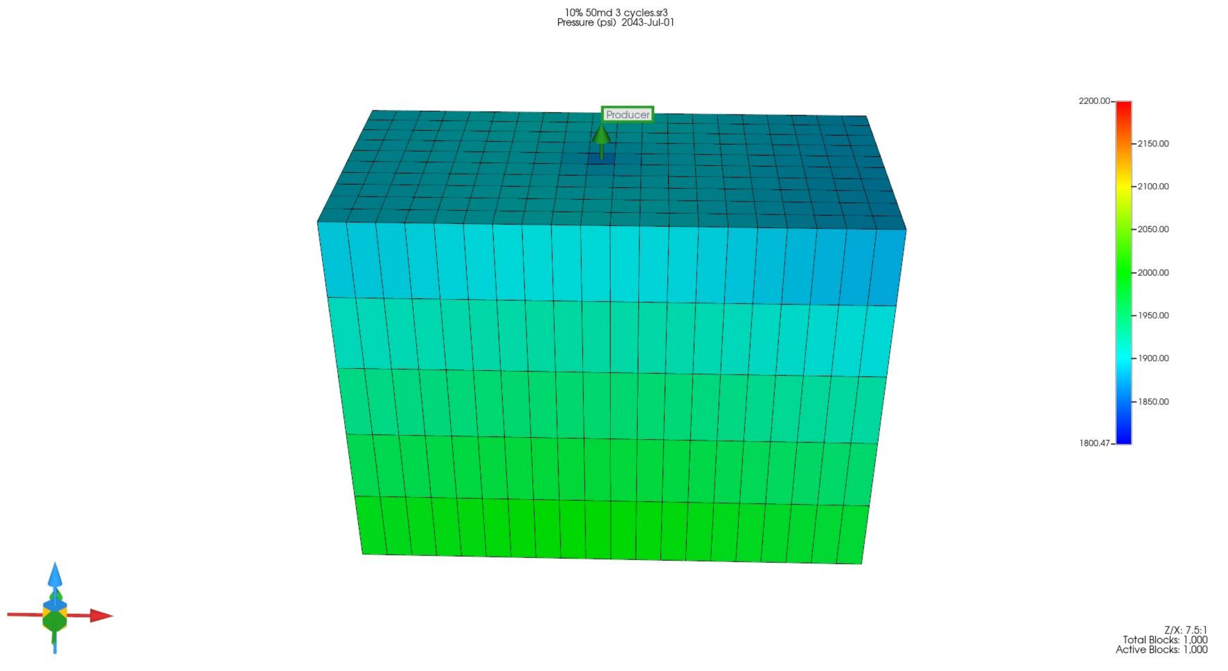


Figure 30. Reservoir pressure after 1st cycle CO_2 injection.

The initial reservoir pressure was 2000 psi. As shown in Figure 29, the reservoir pressure at primary depletion was 1800 psi at the top of the formation and 1900 psi at the bottom of the formation. Figure 30 demonstrates the reservoir repressurized after 1st cycle of CO_2 injection. The reservoir pressure was 1900 psi at the top formation and 2000 psi at the bottom formation.

As shown in Table 17, the cumulative injected CO_2 was 7200 tons for 3 cycles and the cumulative produced heavy oil was 60.71 MSTB or 8138 tons. The ratio between produced oil and injected gas is nearly 1.1. Table 6 from the literature review part demonstrates the ratio between produced oil and injected gas is 1.3. The ratio obtained from the constructed reservoir almost coincides with the ratio obtained from the literature review. As shown in Table 6, the soaking stage, the number of cycles and the injected volume of CO2 per cycle for the constructed reservoirs and the reservoir from the literature review are the same. Figure 14 illustrates a considerable increase in incremental oil production in 2 and 3 cycles for wells. The same trend was observed in Figure 28.

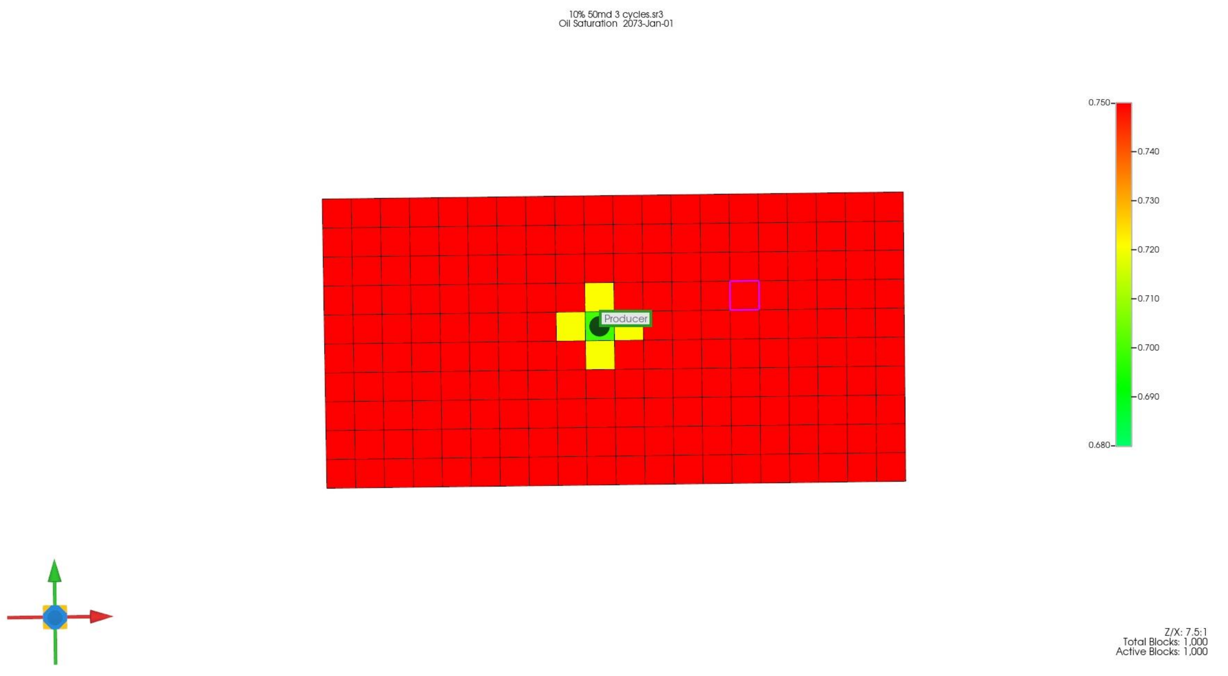


Figure 31. Oil saturation at the end of the production period

Figure 31 shows the oil saturation at the end of the production period. This is a schematic view of the reservoir at the top. The oil saturation decreased near the region of the well.

4.2 Effect of Injection Rate

The simulation results are presented in Figures 32, 33 and 34 and summarized in Table 18. The study was conducted on a reservoir with 20% porosity and permeability 200 md. The base scenario was chosen, and the recovery factor was 6.54%. The initial oil-in-place of the reservoir was 363.99 MSTB. Three different CO_2 injection rates were used, namely 30 tons per day, 52.6 tons per day, and 80 tons per day. The incremental oil recovery and cumulative oil production were measured and compared for each injection rate. The results of the study show that increasing the injection rate of CO_2 leads to higher incremental oil recovery and cumulative oil production.

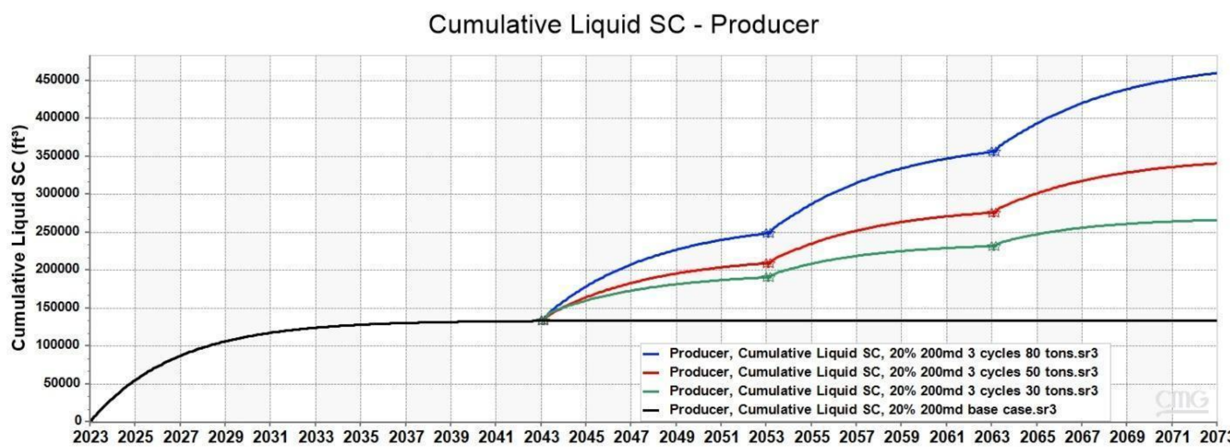


Figure 32. Cumulative Liquid Production for different injection rates vs. Time

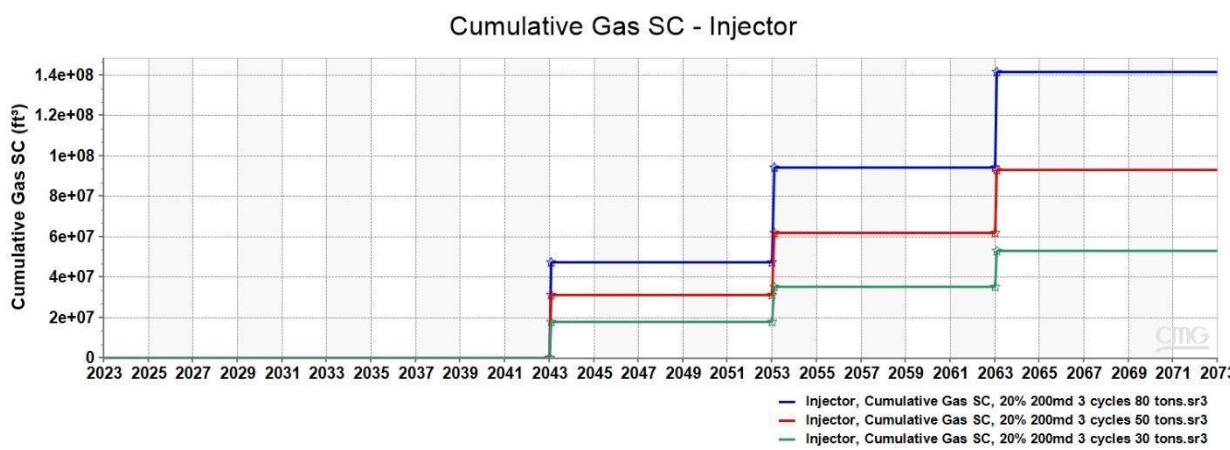


Figure 33. Cumulative Injected CO2 gas for different injection rates vs. Time

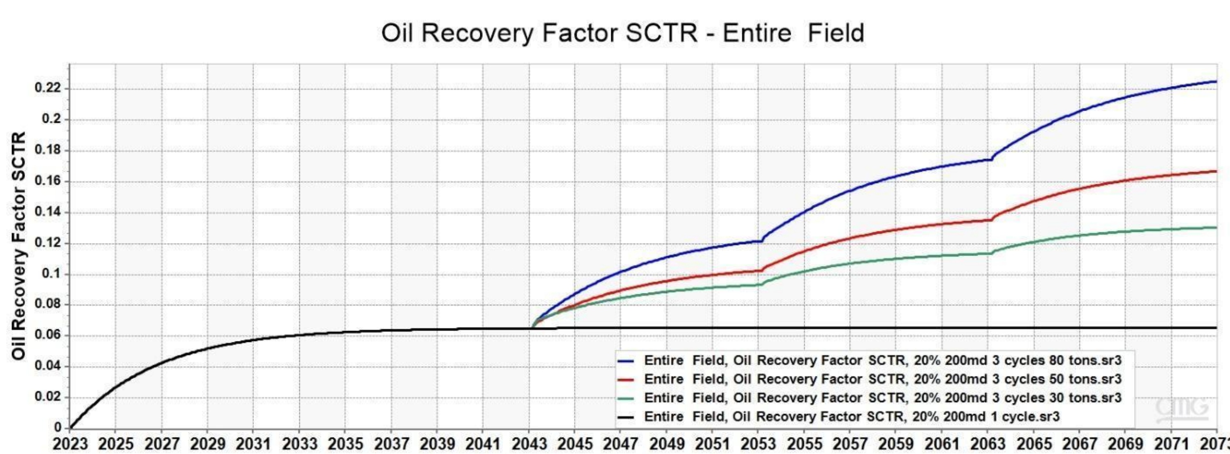


Figure 34. Oil recovery factor for different injection rates vs. Time

Table 18. Cumulative oil production, injected CO_2 gas, and recovery factor for Case 2

20% 200md	Without injection	30 tons per day	52.6 tons per day	80 tons per day
Cumulative injected CO_2, tons	0	2700	6312	7200
Cumulative Liquid Production, MSTB	23.80	47.43	60.71	81.95
Oil recovery Factor, %	6.54	13.08	16.68	22.52
Oil/ CO_2 Ratio	0	0.0025	0.0018	0.0025

The incremental oil recovery increased from 13.08% to 22.52% as the injection rate increased from 30 to 80 tons per day. Similarly, the cumulative oil production increased from 47.44 MSTB to 81.96 MSTB as the injection rate increased from 30 to 80 tons per day. The ratio of extracted oil and injected CO_2 is the same for 30 tons per day and 80 tons per day. The most optimal injection rate will be 80 tons per day since the oil recovery factor is higher compared to other injection rates. Also, the total injected CO_2 will be more, which will be stored inside the formation. The reason why increasing the injection rate of CO_2 leads to higher oil recovery and production is that the higher injection rate results in a better reservoir sweep efficiency. When the CO_2 is injected into the reservoir, it displaces the oil and pushes it towards the production well. The displacement efficiency depends on the mobility ratio between the injected fluid and the oil. If the mobility ratio is low, the injected fluid will bypass the oil, resulting in a lower recovery. However, by increasing the injection rate, the mobility ratio is improved, and the injected fluid can reach the oil more effectively. Additionally, a higher injection rate also results in a higher-pressure gradient, which can help push the CO_2 deeper into the reservoir, thereby contacting more oil. This leads to better sweep efficiency and higher recovery. Table 6 shows that the total amount of injected CO_2 per cycle ranged from 24 tons to 99 tons, the soaking period ranged from 28 to 64 days, and the incremental amount of oil ranged from 38.3 tons to 397.7 tons. Table 28 demonstrates the same trend. The total amount of injected CO_2 per cycle ranged from 30 tons to 80 tons, the soaking period ranged from 30 to 60 days, and the incremental amount of oil ranged from 47.4 tons to 81.95 tons.

4.3 Effect of Soaking Period

The simulation results are presented in Figure 35 and summarized in Table 19. One of the key parameters, in this case, is the soaking period, which is the time the injected CO_2 is allowed to soak into the reservoir before production is resumed. In this section, we investigated the effect of the soaking period on cumulative oil production and incremental oil recovery using a base scenario of 20% porosity and 200 md permeability, a CO_2 injection rate of 80 tonnes per day, and three soaking periods of 0 days, 30 days, and 60 days.

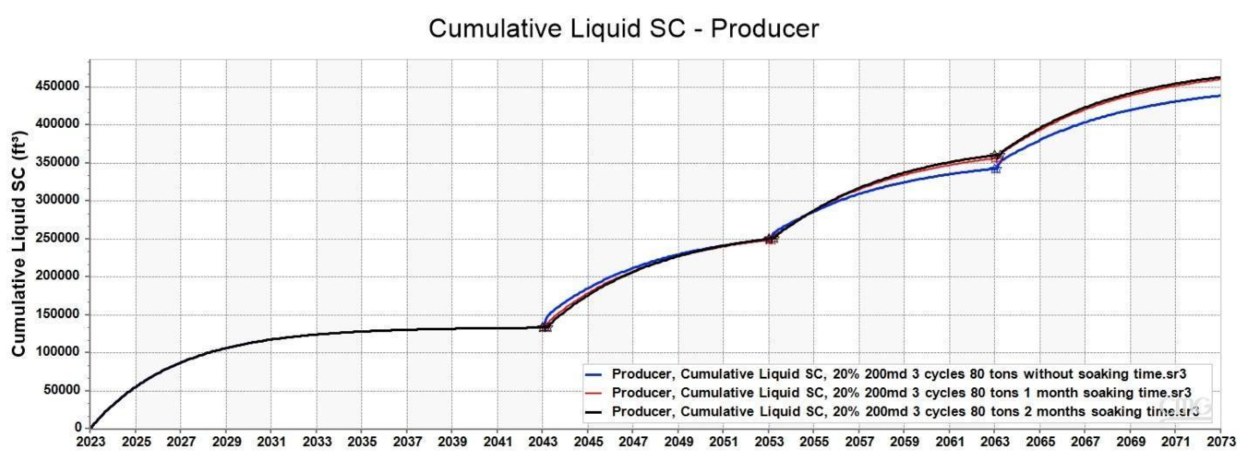


Figure 35. Cumulative oil production for different soaking periods vs. Time

Table 19. Recovery factor, oil production, and CO_2 injected volume for different soaking periods

Soaking time	Oil recovery factor, %	Cumulative produced liquid, MSTB	Cumulative injected CO_2, tons

0	21.45	78.13	7200
1 month	22.52	81.95	7200
2 months	22.66	82.45	7200

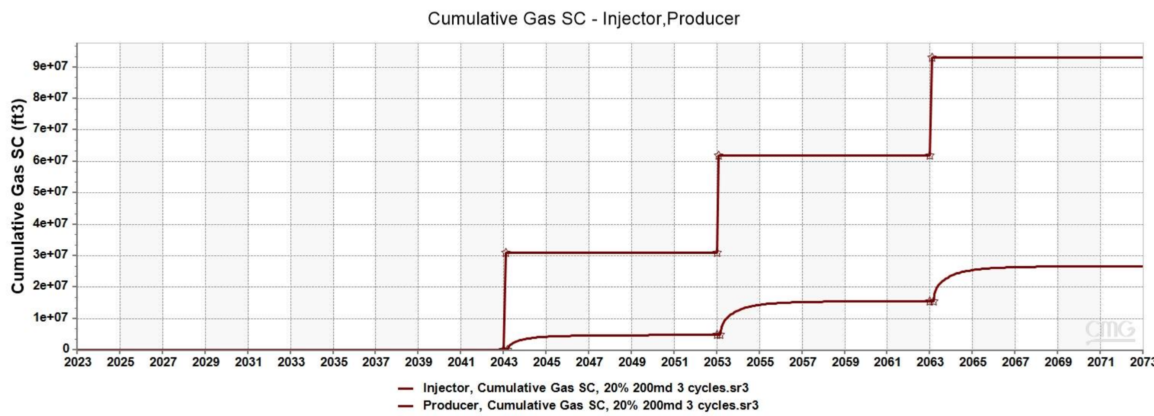


Figure 36. Cumulative Gas produced and injected vs. Time

The results from Figure 35 and Table 19 of the study indicates that the cumulative oil production and incremental oil recovery increase with an increasing soaking period. The oil recovery factors for soaking periods of 0 days, 30 days, and 60 days were 21.45%, 22.52%, and 22.66%, respectively. The increase in cumulative oil production can be attributed to the increased contact time between the injected CO_2 and the oil. The longer the soaking period, the greater the chance for the CO_2 to diffuse into the oil, resulting in better recovery.

Although the cumulative oil production and incremental oil recovery increased with an increasing soaking period, the optimum soaking period was found to be 30 days. The reason for this can be attributed to the diminishing returns of the additional soaking time. After 30 days, the increase in oil recovery becomes marginal, and the energy required for the additional soaking time may not be cost-effective as can be seen in the 2 month of the soaking stage. In the case study, the cumulative oil production increased from 81.95 MSTB after a 30-day soaking period to 82.45 MSTB after a 60-day soaking period. This means that the additional 30-day soaking period only resulted in an incremental oil recovery of 0.5 MSTB.

The difference between the soaking periods was 30 days since the time interval was chosen in 1 month. It was not possible to select a time interval of 15 days for the soaking stage.

Figure 36 shows the Cumulative CO_2 gas production and injection. The soaking period was 30 days. This value was selected from the calculation of the average soaking time shown in Table 6. The cumulative volume of injected and produced CO_2 was 7200 tons and 1895 tons, respectively. The average percentage of produced CO_2 was 25% after injection. When the soaking periods were 0 and 90 days, the cumulative volume of produced CO_2 was 1875 tons and 1915 tons, respectively. The range difference of cumulative produced CO_2 at 30 days and 60 days soaking periods was insignificant. Hence, 30 days was determined to be the optimum soaking period for the reservoir.

The increase in oil recovery and cumulative oil production with an increasing soaking period can be attributed to several factors. First, the CO_2 needs time to dissolve and diffuse into the oil, which takes longer for larger reservoirs or when the oil is more viscous. Secondly, the CO_2 reacts with the oil to reduce its viscosity, making it easier to flow towards the wellbore. Third, CO_2 can mobilize trapped oil by reducing the interfacial tension between the oil and rock surfaces.

However, the increase in oil recovery and cumulative oil production with an increasing soaking period is not linear. After a certain point, the incremental oil recovery and cumulative oil production may plateau as can be seen from Figure 35 or even decline due to factors such as CO_2 breakthrough, pressure depletion, and reduced contact between the injected CO_2 and the oil.

4.4 Economic Analysis

The average rate of CO_2 gas injection in case 1 was 52.6 tons per day. The injection period for one cycle was 1 month. Three cycles were performed for reservoirs with different porosity and permeability. The total injected CO_2 gas for 3 cycles was 4732 tons. Costs for onshore pipeline transportation and storage range from \$4 to \$45 per t CO_2, based on major sources of variation such as distance travelled, reservoir geology, and transport cost variations such as pipeline construction costs (Smith et al., 2021). It is assumed that an average price of 45\$ per ton was chosen for pumping CO_2 gas into the reservoir. The total price of injected CO_2 gas for 3 cycles in case 1 was 212940\$. The total volume of oil produced increased in case 1 by 27.55 MSTB over 3 cycles of the CO_2 huff-n-puff technique in a reservoir with a porosity of 10% and permeability of 50 md. In addition, the cumulative oil produced increased by 32.98 MMSTB and 36.91 MSTB over 3 cycles due to the implementation of this method in reservoirs with porosity and permeability of 15%, 100md and 20%, 200md. According to Alberta Energy Regulator, the price of Western Canadian Select is 69$ per barrel in 2023 (Crude Oil Prices, 2022). The profit, revenue and cost from the extracted oil in different reservoirs are represented in Table 20. Reservoirs with high porosity and permeability give a greater profit compared to a tight reservoir.

Table 20. The profit, revenue and cost for case 1

	10%, 50 md	15%, 100 md	20%, 200 md
Injected CO_2, tons	4732	4732	4732
Costs of CO_2 gas injection, $	212940	212940	212940
Additional oil production by CO_2 injection, MSTB	39.44	50.83	60.72
Revenue from oil produced by CO_2 injection, $	2721153	3507408	4189473
Net profit, $	2508213	3294468	3976533

Table 21. The profit, revenue and cost for case 2

	30 tons per day	52.6 tons per day	80 tons per day
Injected CO_2, tons	2700	4732	7200
Costs of CO_2, $	121500	212940	324000
Additional oil produced by CO_2 injection, MSTB	47.44	60.72	81.96
Revenue from additional oil produced by CO_2 injection, $	3273015	4189473	5655102

Net profit by CO_2 injection, $	3151515	3976533	5331102

Based on the results of our study, it can be concluded that the CO_2 huff and puff method is an effective way to increase oil production and generate profits in the petroleum industry. We have investigated the impact of changing the CO_2 injection rate on the profitability of the project, and the results show that increasing the injection rate to 80 tons per day provided the most profitable outcome. This is because the increase in injection rate leads to a more efficient oil recovery from the reservoir, which results in higher revenue. It is important to note that the cost of CO_2 gas injection increases with the injection rate. In case 2, where the injection rate was increased to 80 tons per day, the cost of CO_2 gas injection was 324000$. However, the revenue generated from oil production was much higher, with a total profit of 5655102$, resulting in a net profit of 5331102$. In contrast, the net profits were lower for the injection rates of 52.6 and 30 tons per day, at 3976533$ and 3151515$, respectively. The cost of CO_2 gas injection was also lower for these injection rates, at 212940$ and 121500$, respectively. Overall, the results of our study demonstrate the economic viability of the CO_2 huff and puff method for enhancing oil recovery. The findings also suggest that it is essential to optimize the injection rate to achieve maximum profit. However, it is essential to consider the cost of CO_2 gas injection and other operational expenses while considering the profitability of the project.

5 Conclusions and Recommendations

Based on the case studies the optimal parameters for the CO_2 huff-n-puff method were chosen. By increasing the number of cycles of CO_2 Huff and Puff techniques, the oil production and incremental oil recovery increase. The optimal number of cycles will depend on economic and technical factors, which will decide the number of cycles needed for each reservoir. Another parameter was the CO2 injection rate. According to the simulation results, by increasing the CO_2 injection rate, the oil production and recovery factor increase. The best results are shown in the case with 80 tons per day of CO_2 injection. The optimal period for the soaking stage was chosen as 30 days. Below, there are some conclusions that can be drawn from the research:

1. The best effect from using 3 cycles of the CO_2 huff-n-puff technique can be noticed in the first scenario with 10% porosity and 50 md of permeability.

2. By increasing the number of cycles in the CO_2 huff-n-puff method, the oil production and recovery factor can increase because it allows for more efficient use of the injected CO_2. As the number of cycles increases, the pressure within the reservoir continues to rise, leading to the greater displacement of oil. Efficient number of cycles for case 1 with 10% porosity and 50 md is 2, while for the other two scenarios, 3 cycles of the CO2 Huff and Puff method is economically beneficial.

3. A higher injection rate results in a better reservoir sweep efficiency. Additionally, a higher injection rate also results in a higher-pressure gradient, which can help push the CO_2 deeper into the reservoir, thereby contacting more oil. The optimal CO_2 injection rate was chosen as 80 tons per day according to the simulation results.

4. The increase in oil recovery and cumulative oil production with an increasing soaking period is not linear. 30 days was determined to be the optimum soaking period for a particular reservoir.

5. The highest net profit was obtained for a reservoir with a porosity of 20% and a permeability of 200 md in case 1 and an injection rate of 80 tons per day in case 2.

Limitations of our study:

1. Poor Reservoir Conditions: The results of this study are limited by the poor reservoir conditions encountered. Specifically, the depth of the reservoir being studied, which was 8000 ft, is not common in the industry. This may have an effect on the efficiency of the CO2 Huff and Puff method to other tight oil reservoirs which have less reservoir depths.
2. Limited Permeability Variations: The permeability values used in this study were limited to base case scenarios of 50, 100, and 200 md. This means that the study did not investigate the effect of the CO2 huff and puff method on reservoirs with significantly different permeability values. As a result, the effect of the CO2 Huff and Puff method on more permeable reservoirs may not seem to be totally covered. For example, in the case 1, for all base scenarios, the oil recovery remained at 6.54% with no difference when the permeability was increased.
3. Problems with Constraints: The study was also limited by the constraints imposed during the simulation process. In our case, the main constraint was the bottomhole pressure. To make our results more realistic, we tried to control the bottomhole pressure in the range of 1800-2000 psi. These constraints may have affected the accuracy and precision of the results obtained. The constraints may have also prevented the study from exploring more nuanced variations in the simulation process.
4. Need for More Complicated Simulation: The complexity of the CO2 huff and puff method and the dynamic nature of reservoirs make it difficult to accurately simulate the process. Therefore, the study may have been limited by the level of complexity that was feasible to incorporate into the simulation process. This may have resulted in a lack of precision and accuracy in the results obtained.

It is recommended to optimize the number of cycles, CO_2 injected rate, and soaking period based on the reservoir characteristics to achieve maximum oil recovery. It is also recommended to continuously monitor the CO_2 Huff and Puff operations to detect any possible CO_2 breakthrough and optimize the injection strategy. Further research can be conducted to optimize the CO_2 Huff and Puff method by investigating the effect of different parameters such as reservoir temperature, pressure, and CO_2 concentration.

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7. Appendixes

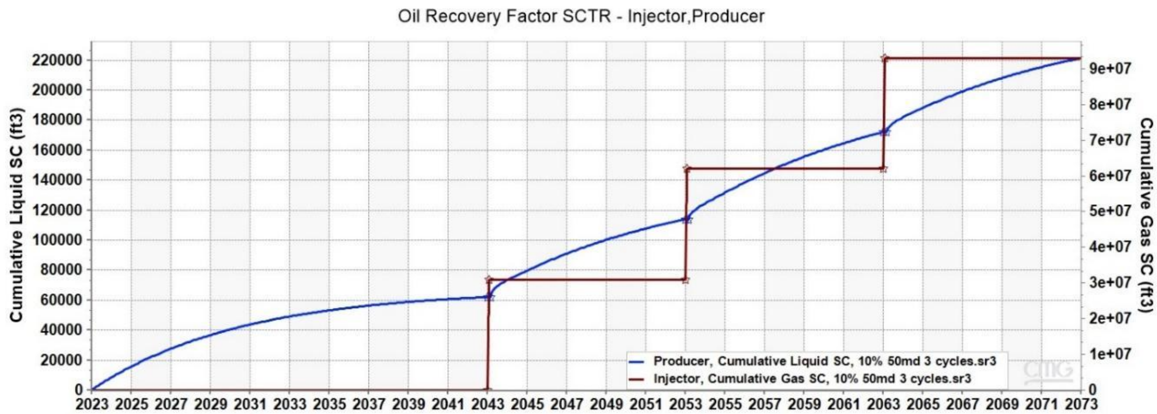

Figure 29. Cumulative Liquid and Gas for 10% porosity and 50 md permeability

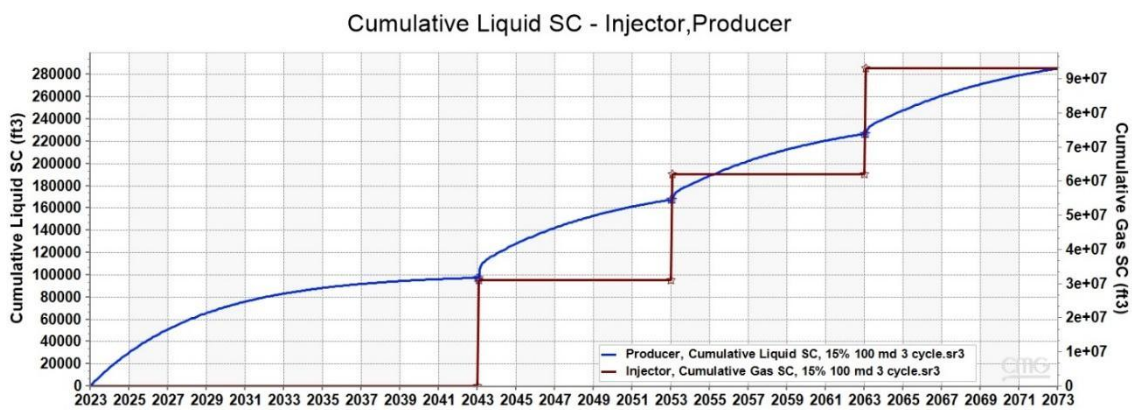

Figure 29. Cumulative Liquid and Gas for 15% porosity and 100 md permeability

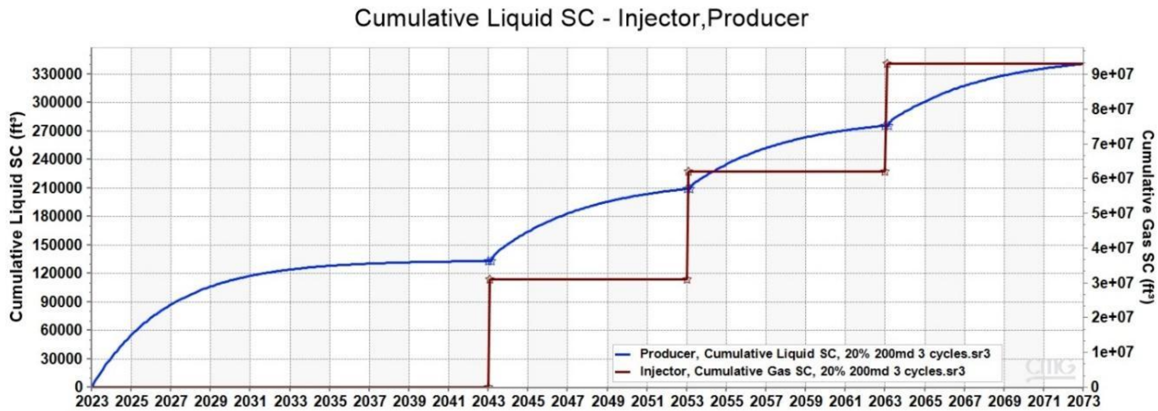

Figure 30. Cumulative Liquid and Gas for 20% porosity and 200 md permeability