Dual Benefits of Enhanced Oil Recovery and CO$_2$ Sequestration: The Impact of CO$_2$ Injection Approach on Oil Recovery

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Injection of CO$_2$ to enhance oil recovery is widely used due to its multiple advantages such as mobilizing the oil and sequestration of carbon dioxide. Injection of CO$_2$ can enhance oil recovery by reducing oil viscosity and improving overall fluid mobility. However, several problems are associated with CO$_2$ injection such as viscous fingering, gravity override, and CO$_2$ channeling that results in early gas breakthrough, low sweep efficiency, and low ultimate oil recovery. In this study, dual benefits of CO$_2$ injection are presented: enhancing oil recovery and sequestering carbon dioxide. In this work, different scenarios of field scale simulation were conducted to evaluate oil recovery during CO$_2$ injection, and the CMG (Computer Modeling Group) software package was used. Three main scenarios were examined which are CO$_2$ injection into the reservoir, CO$_2$ injection into the aquifer, and CO$_2$ injection into the aquifer followed by waterflooding. Also, three well configurations were utilized—all injectors and producers are drilled vertically, all wells are drilled horizontally, and vertical injectors and horizontal producers are used. Therefore, the oil recovery profiles were examined for nine scenarios over a 20-year period. In all simulated models, CO$_2$ injection was started at the residual oil saturation (S$_{or}$) conditions, to represent the cases of depleted oil reservoirs. The results indicated that the highest oil recovery of 73% of the original oil-in-place (OOIP) can be achieved by injecting CO$_2$ into the reservoir, utilizing vertical injectors and producers. While injecting CO$_2$ into aquifers can significantly enhance oil recovery by around 68–70% of the OOIP, using horizontal wells can provide more oil recovery (67.7%) than that using vertical wells (54.8%), in the same conditions. Moreover, around 7,928 tons of carbon dioxide can be sequestered in underground formations, on average. Finally, CO$_2$ injection outperformed the conventional waterflooding, where 68 and 12% of the OOIP were obtained, respectively. Overall, injection of CO$_2$ into the depleted reservoir can provide dual benefits of CO$_2$ sequestration and improved oil recovery. CO$_2$ can be injected into the water zone resulting in a slow release of CO$_2$ which will reduce the fluid viscosity, enhance oil recovery, and reduce the greenhouse effect.

Keywords: enhanced oil recovery, CO$_2$ injection, dual benefits, high oil recovery, CO$_2$ sequestration

INTRODUCTION

Global warming is one of the most challenging problems that have multiple effects on human life (Goel and Bhatt, 2012). The emission of carbon dioxide (CO_2) and methane gases is believed to be the main cause of climate change (Rehman et al., 2020). Several approaches are used to reduce the amount of CO_2 including CO_2 storage or sequestration in different types of underground formations (Hassanpouryouzband et al., 2018; Hassanpouryouzband et al., 2019; Hasssanpouryouzband et al., 2021). The injection of CO_2 into oil and gas reservoirs is widely implemented in order to increase oil production and sequestrate CO_2 (Orr and Taber, 1984; Gozalpour et al., 2005; Jia et al., 2019; Hamza et al., 2021). Injection of CO_2 can be considered dual-benefit operations: recovering more oil as well as reducing the greenhouse effect of CO_2 (Ettehadtavakkol et al., 2014; Dong et al., 2021; Jeffry et al., 2021). Carbon dioxide injection for increasing oil production is now a well-established technique that can be used in different types of reservoirs such as depleted and non-depleted reservoirs (Brock and Bryan, 1989; Cherepovitsyn et al., 2018; Hamza et al., 2021; Wang et al., 2021a; Wang et al., 2021b). Injection of CO_2 presents an effective enhanced oil recovery (EOR) approach for several reasons such as low CO_2-miscibility pressure, CO_2 sequestration, oil swelling, and viscosity reduction (Wei et al., 2017; Hafez et al., 2021; Wang et al., 2022). CO_2 injection can improve the oil production from depleted reservoirs through different mechanisms such as mobilizing the residual oil, pressurizing the reservoir, and reducing the interfacial forces between oil and CO_2 (Bennion and Bachu, 2006; Perera et al., 2016; Rezaei et al., 2021).

Several factors are controlling the performance of CO_2-EOR treatment such as the gas injection rate, minimum miscibility pressure (MMP), interfacial tension (IFT), operating conditions, and reservoir characteristics (Talebian et al., 2014; Wei et al., 2017). Usually, injection of CO_2 at pressures above the MMP will lead to miscible flooding, and therefore, more oil can be recovered compared to that of immiscible flooding (Bennion and Bachu, 2006; Jia et al., 2019; Hafez et al., 2021). The operating conditions, reservoir characteristics, IFT, formation temperature, and CO_2 purity are the common factors that control the degree of miscibility during CO_2 injection. Moreover, the gas injection rate and the location where the gas is injected can significantly affect the CO_2 performance (Perera et al., 2016; Shi et al., 2019). Using a high injection rate can help in maintaining the reservoir pressure, but it may lead to faster gas breakthrough (Talebian et al., 2014; Jia et al., 2019). Consequently, the overall sweep efficiency and the ultimate oil recovery will be decreased (Perera et al., 2016). Moreover, CO_2 can be injected directly into the oil zone to swell and displace the oil; however, injecting CO_2 gas into the water zone can also improve oil recovery, especially in heterogeneous reservoirs. Injection of carbon dioxide into the water zone, below the oil reservoir, can lead to slow release of the CO_2 gas; therefore, more favorable displacement conditions will be induced.

The CO_2-EOR approach presents a very attractive technique compared to conventional approaches such as waterflooding, especially in depleted reservoirs (Ampomah et al., 2016; Shi et al., 2019; Imanovs et al., 2020). The depleted reservoirs usually have low oil saturation; therefore, using waterflooding could lead to trapping the remaining oil and reducing the overall oil recovery (Hawkes et al., 2004; Raza et al., 2017). On the contrary, the injection of CO_2 into the depleted reservoirs can lead to oil swelling which will increase the oil volume and improve oil mobility (Dai et al., 2017; Dudek et al., 2021). Also, CO_2 injection can lead to a significant reduction in the oil viscosity; therefore, less drawdown pressure would be required to mobilize and recover the oil (Farokhpoor et al., 2013). Moreover, CO_2 can alter the reservoir wettability to less oil-wet conditions resulting in higher oil recovery based on the wettability alteration mechanism (Chiquet et al., 2007; Chen et al., 2019).

The performance of CO_2 flooding can be reduced by several phenomena such as gravity override and viscous fingering, due to the considerable differences between the density/viscosity of the crude oil and CO_2 (Lake, 1989; Rezaei et al., 2021). Therefore, poor sweep efficiency can be induced during CO_2 flooding, leading to fast CO_2 breakthrough and low oil recovery (Chang and Grigg, 1999; Le et al., 2008). Hence, different techniques have been developed to improve the CO_2 mobility behavior mainly by increasing the CO_2 density and viscosity (Alam et al., 2015; Ampomah et al., 2016). Foam-assisted CO_2 is presented as a very effective approach in controlling CO_2 mobility leading to improved oil displacement and more oil recovery (Talebian et al., 2013; Talebian et al., 2014). Recently, a novel approach of *in situ* CO_2 generation showed a promising oil recovery technique and late CO_2 breakthrough (Shiau et al., 2010; Abdelgawad and Mahmoud, 2015; Wang et al., 2016, 2018).

The limitations of CO_2 flooding can be reduced by utilizing the slow release of CO_2 gases, which can be performed by injecting the CO_2 gas into the water zone below oil layers allowing CO_2 to move slowly into the oil zone (Alam et al., 2015). The released CO_2 can interact with the crude oil and improve the fluid flow behavior (Wang et al., 2019). Several studies were carried out to examine the performance of CO_2 using different experimental and simulation techniques. However, the concept of slow CO_2 release is not fully covered in the literature, especially for depleted reservoirs. In this work, CMG simulation was used to evaluate oil recovery using different injection scenarios. The residual oil saturation in the depleted reservoir was monitored as a function of CO_2 injection time. Also, the recovered oil was determined and discussed for all cases. The amount of CO_2 that can be stored within the reservoir or aquifer formations was estimated based on the injection rate and the treatment time. Finally, the performance of CO_2 injection was compared with that of the conventional waterflooding technique, using depleted reservoir conditions.

METHODOLOGY

Reservoir Model Description

In this work, the reservoir dimensions used are 8000*6000*1000 ft for *X*, *Y*, and *Z* directions. The reservoir model consists of 50 grid blocks in the horizontal direction and 40 grid blocks in the vertical direction. The number of blocks was selected by running multiple scenarios of different

FIGURE 1 | Reservoir model used in this study.
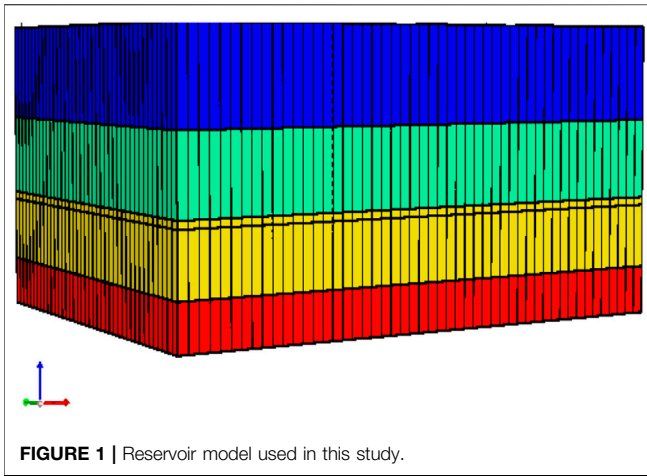
block numbers, and the used grid number was found to be representative and computationally accepted. It should be noted that the same number of grids was used for all scenarios in order to minimize the uncertainty and improve the work reliability. Also, the reservoir formation was divided into five layers to account for the reservoir heterogeneity. The first three layers represent the oil zones, while the water aquifer is represented by the two layers at the bottom. The porosity distribution is 18, 17, 10, 18, and 15% for the five layers, while the layers' permeability was varied between 75 and 100 mD. A thin layer of 5 ft thickness and 0.01 mD permeability was placed between the water aquifer and the reservoir formations, to help in the slow release of CO_2. Moreover, other reservoir properties such as the reservoir pressure of 4,000 psi, minimum miscibility pressure (MMP) of 1600 psi, and gas oil contact of 9,000 ft were used, which are the average values for typical reservoirs in the region. **Figure 1** shows the reservoir model used in this study.

In addition, the well properties are defined as follows: the maximum injection pressure for injectors is 5,500 psi, the operating bottom hole pressure (BHP) for producers is 1800 psi, the maximum allowable gas–oil ratio (GOR) is 8000 SCF/bbl, and the maximum allowable water cut is 0.99. Also, a well radius of 0.625 ft and a skin factor of 1.5 were used, as suggested by many studies (Jacob, 1947; Bresciani et al., 2020). **Figures 2**, **3** show the relative permeability data used in this work for oil–water and gas–oil systems, respectively. Also, the relative permeability to oil was determined as a function of gas, water, and oil saturation, as shown in **Figure 4**. The relative permeability profiles were obtained using Correy's model available in CMG software (Correy et al., 1956).

Simulated Scenarios

The simulation work was carried out using CMG (Computer Modeling Group) software, and CMG Launcher 2015.10 (Builder 2015.1) was used in this work. Various scenarios of gas injection were simulated. All the simulations were started with the residual oil saturation (S_{or}) condition, representing depleted oil reservoir conditions. Three main scenarios were examined in this work: CO_2 injection into the reservoir, CO_2 injection into the aquifer, and CO_2 injection into the aquifer followed by water injection. CO_2 is highly soluble in water (Xing et al., 2012); the CO_2 solubility in the formation brine is a strong function of pressure, temperature, and salinity (Duan and Sun 2003; Duan et al., 2006). Increasing the pressure showed a rapid increase in the CO_2 solubility, while the CO_2 solubility decreased with the increasing temperature or salinity. The models developed by Duan and Sun (2003) and Duan et al. (2006) were used in this work to estimate the CO_2 solubility in water.

In addition, in all scenarios, three well schemes were utilized: horizontal wells (injectors and producers), vertical wells, and vertical injectors and horizontal producers. Therefore, a total of nine scenarios are discussed in this work. The profiles of oil recovery,

FIGURE 2 | Water and oil relative permeability curves as a function of water saturation.
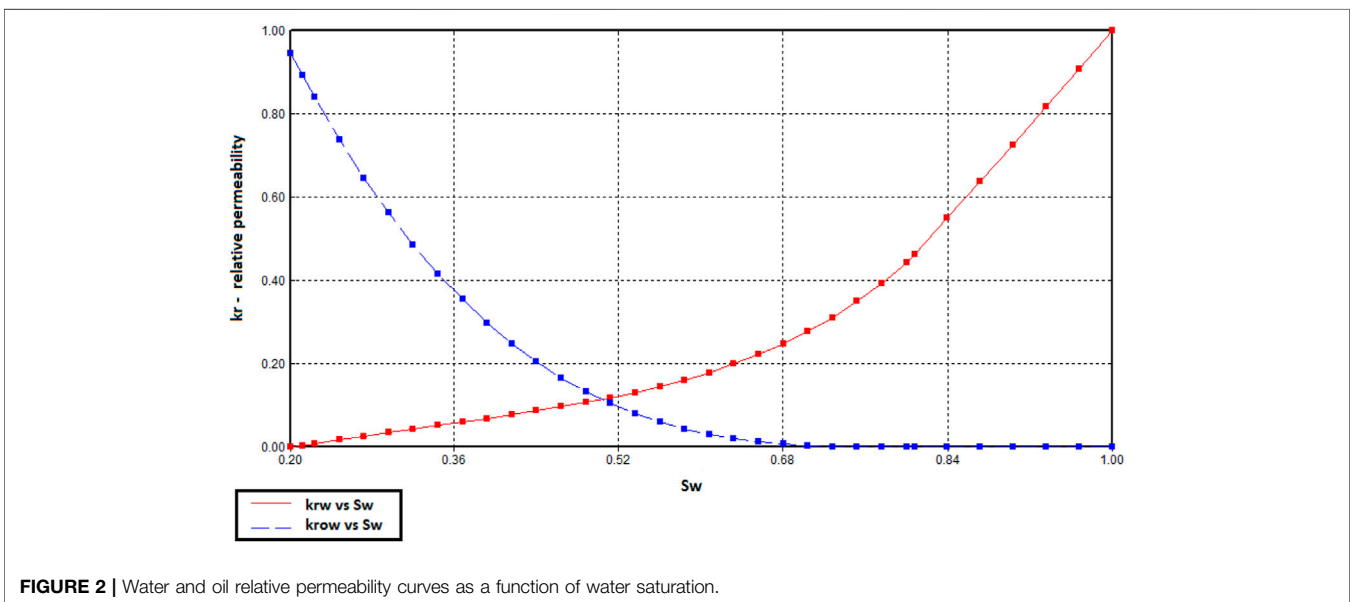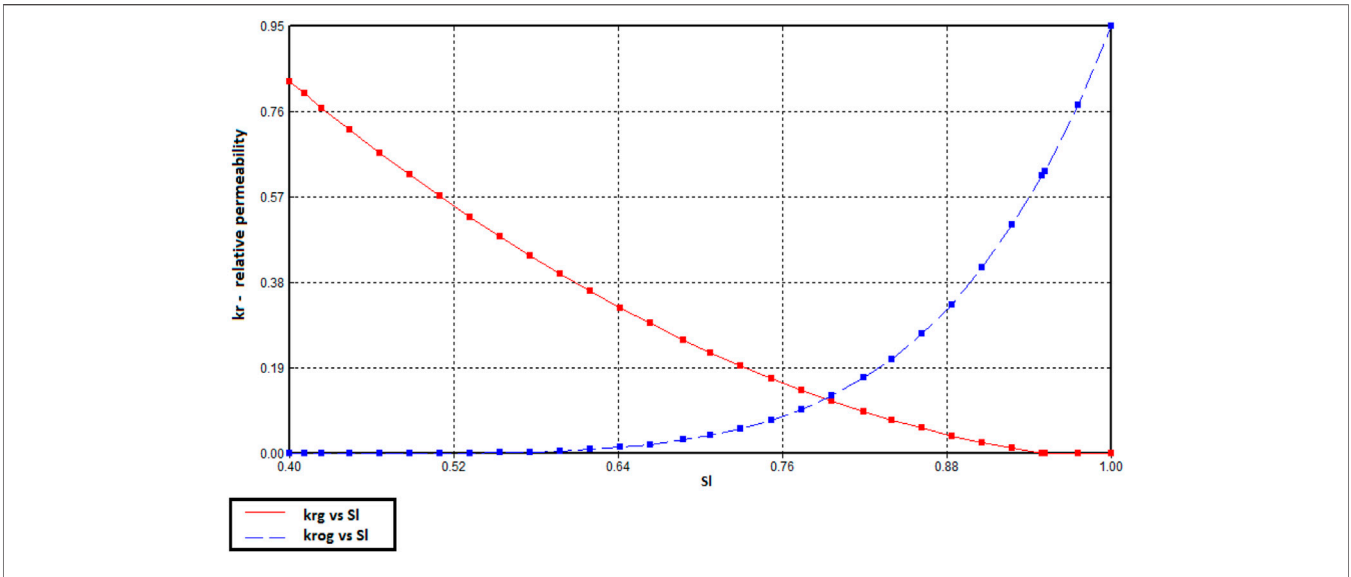
FIGURE 3 | Gas and oil relative permeability curves as a function of gas saturation.
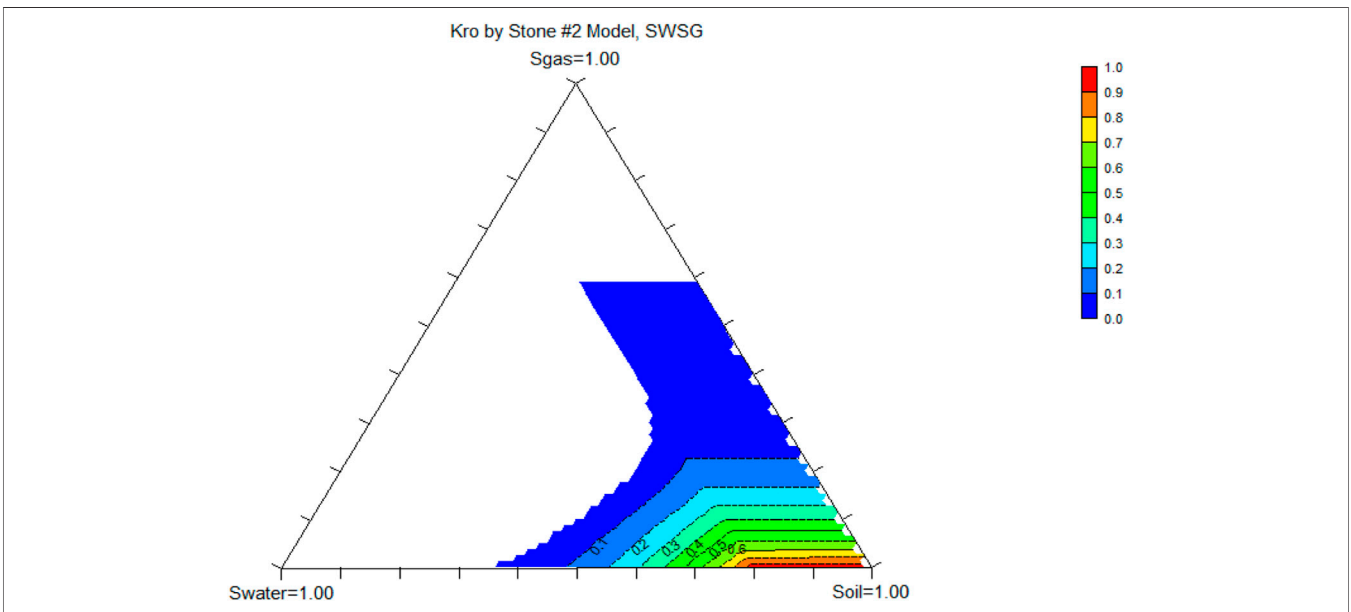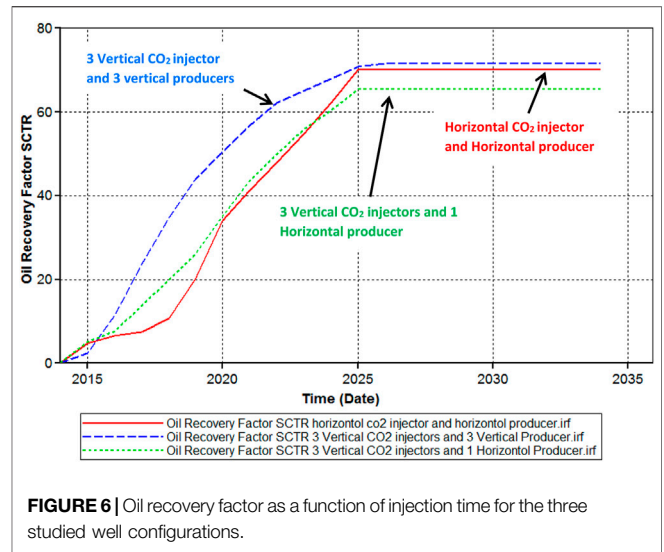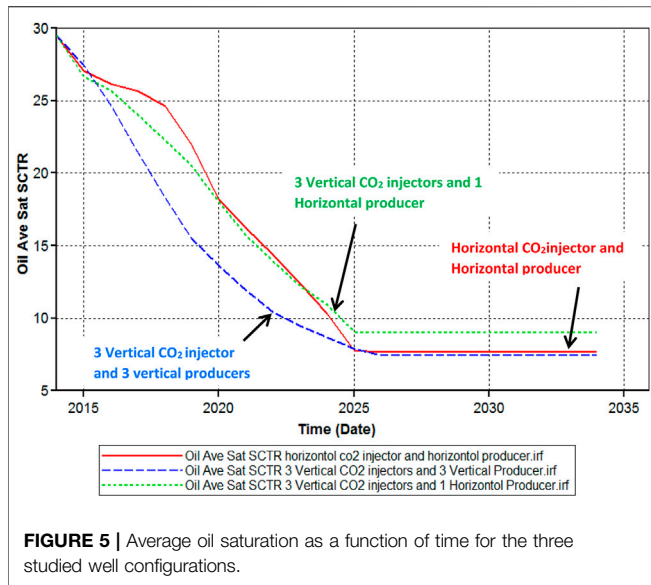

FIGURE 4 | Oil relative permeability as a function of gas, water, and oil saturation.

reservoir pressure, and CO_2 saturation are analyzed. The reservoir performance was examined for a period of 20 years. Around 7,928 tons of carbon dioxide can be sequestered within the reservoir/aquifer formations, on average. It should be noted that the wells' number and locations can affect the simulation results; hence, a consistent reservoir/well model was used in this work in order to minimize the uncertainty and improve the work reliability.
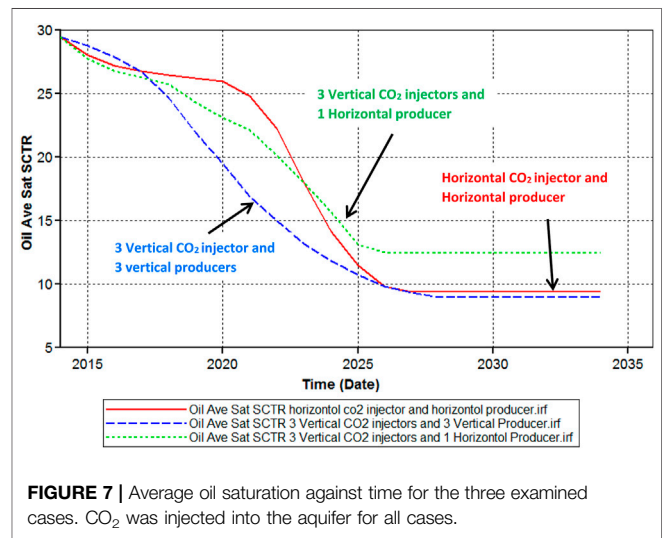
RESULTS AND DISCUSSION

In this work, three main cases were used by varying the location of CO_2 injection from the reservoir to the water zone. Also, different well types were used including vertical, horizontal, and combinations for the production and injection wells. The profile of residual oil saturation and oil recovery is discussed in this part.

FIGURE 5 | Average oil saturation as a function of time for the three studied well configurations.

FIGURE 6 | Oil recovery factor as a function of injection time for the three studied well configurations.

CO_2 Injection Into the Reservoir

In this case, carbon dioxide is injected directly into the reservoir to enhance oil recovery through multiple mechanisms: oil swelling, viscosity reduction, and oil displacement. Three well configurations were used in this case. The first configuration is that both the producer and the injector were drilled horizontally, where one producer and one injector were used. The second configuration is that both producers and injectors were drilled vertically, where three producers and three injectors were used. The third configuration is that the injector wells were drilled vertically, while the producer wells were drilled horizontally, where three vertical gas injectors and one horizontal producer were used. **Figure 5** shows the average oil saturation for the studied well configurations. In this work, the simulation duration is 20 years, and the maximum bottom hole pressure of 5,500 psi was used for the injectors, while a maximum oil production rate of 30000 bbl/day was defined for the producers. For all cases, the average oil saturation decreases with time until reaching an oil saturation less than 10%, indicating that CO_2 injection is effectively enhancing the oil production. Using three injectors and three producers showed the lowest oil saturation, followed by using horizontal wells for injection and production. However, the case of using three vertical injectors and one horizontal producer showed relatively high residual saturation (around 9.5%) revealing relatively low oil recovery compared to other examined scenarios. Also, an injection period of 10 years could be selected as the optimum injection duration, as no further reduction was observed in the oil saturation after 10 years.
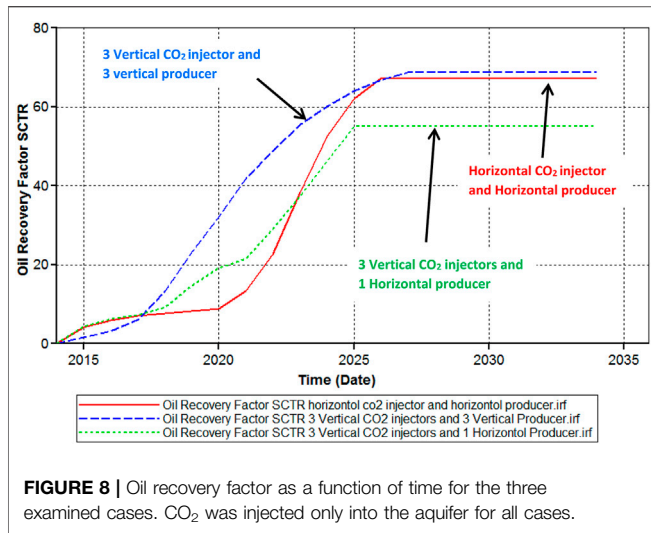
Figure 6 shows the oil recovery factor for the studied well configurations; all cases show a recovery factor more than 65% of the original oil-in-place (OOIP). The highest oil recovery of 72% of the OOIP was achieved using three vertical injectors and three vertical producers, while using horizontal wells showed relatively comparable results: an oil recovery of 70% of the OOIP. However, using three vertical injectors and one horizontal producer showed the lowest oil recovery (around 66%) among the studied cases.

FIGURE 7 | Average oil saturation against time for the three examined cases. CO_2 was injected into the aquifer for all cases.

The main reason for the difference in oil recovery for different scenarios could be the contact area between the wellbore and the reservoir. Usually, increasing this contact area can lead to an increase in oil recovery. Overall, all studied scenarios showed oil recovery more than 65% of the OOIP, indicating effective CO_2 treatment.

CO_2 Injection Into the Aquifer

In this case, three well schemes were examined by changing the well type from horizontal to vertical for injectors and producers. The first case is that all wells were drilled horizontally, where one producer and one injector were used. The second case is that all wells were drilled vertically, where three producers and three injectors were used. Finally, horizontal producers and vertical injectors were studied, where three vertical gas injectors and one horizontal producer were used. Similar to the previous case of CO_2 injection into the reservoir, a simulation time of 20 years was used to examine the recovery profiles. Also, the maximum

FIGURE 8 | Oil recovery factor as a function of time for the three examined cases. CO_2 was injected only into the aquifer for all cases.

FIGURE 9 | Average oil saturation vs. time for the three examined cases. In all cases, CO_2 was injected into the aquifer which was followed by water injection.

pressure of 5,500 psi was used for the injectors, and the maximum production of 30000 bbl/day was defined.

Figure 7 shows the profiles of the residual oil saturation for the three studied scenarios. In all cases, CO_2 was injected only into the aquifer and no CO_2 was injected into the reservoir. It should be notated that a thin layer of low permeability is placed between the aquifer and the reservoir to enable the slow release of CO_2 from the aquifer to the reservoir. For all cases, the minimum oil saturation was achieved after 10 years of injection, and no reduction was observed in oil saturation by continuing CO_2 injection after 10 years. Therefore, the optimum CO_2 injection duration could be selected as 10 years. Among all studied cases, three vertical injectors and three vertical producers showed the lowest oil saturation followed by the case of using one horizontal injector and one horizontal producer, where the residual oil saturation of around 9% was achieved. However, using three vertical injectors and one horizontal producer showed the poorest performance, where the residual oil saturation of 13% was obtained. Moreover, the oil recovery profiles for all studied cases are presented in **Figure 8**, where CO_2 was injected only into the aquifer. Using three vertical injectors and three vertical producers showed the highest oil recovery of 69% of the OOIP, followed by using a horizontal injector and producer, where an oil recovery of 68% of the original oil-in-place was observed. However, using three vertical injectors and one horizontal producer gave an oil recovery of 58% of the OOIP. Overall, using three vertical injectors and three vertical producers or using one horizontal injector and one horizontal producer showed very efficient oil recovery as indicated by the residual oil saturation and oil recovery profiles.

CO_2 Injection Into the Aquifer Assisted by Waterflooding

The performance of CO_2 into the aquifer was assisted by injecting water using a sequential approach; CO_2 was injected, and then waterflooding was implemented. Different well types were used similar to the previously discussed cases; all wells are horizontal, all wells are vertical, and producers are horizontal and injectors are vertical. Also, in all scenarios, a maximum injection pressure of
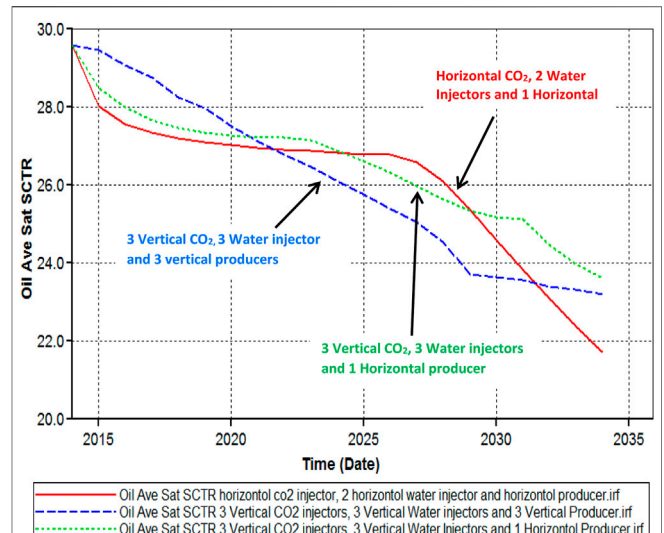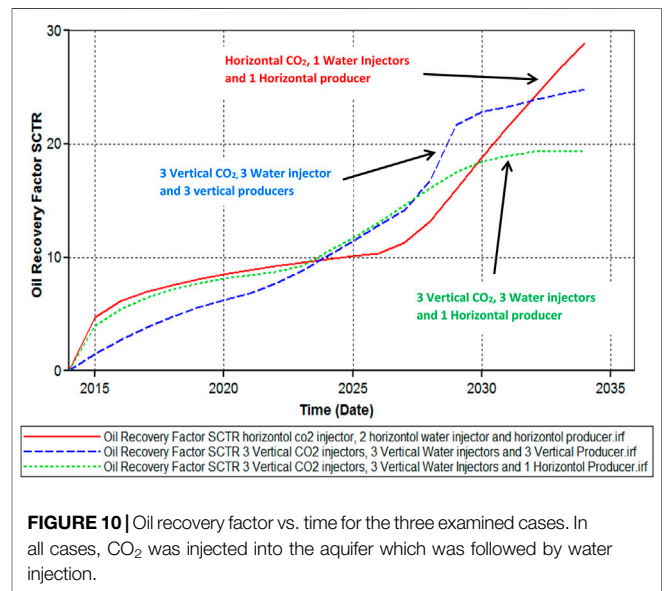

FIGURE 10 | Oil recovery factor vs. time for the three examined cases. In all cases, CO_2 was injected into the aquifer which was followed by water injection.

5,500 psi was used, and a maximum production rate of 30000 bbl/day was applied. **Figure 9** shows the average oil saturation during the injection of CO_2 followed by waterflooding treatment. Using horizontal producers and injectors outperforms all other scenarios, where the residual oil saturation of 21% was achieved as opposed to 23.5% observed for other cases. In contrast to all previous scenarios, the residual oil saturation decreases with time even after 10 years of injection. Also, applying waterflooding showed lower performance, which could be attributed to increasing the volume of trapped oil within the injected water. Furthermore, the oil recovery factor for all studied cases is shown in **Figure 10**. More oil is recovered with time, and no recovery plateau is observed. However,

**TABLE 1 |** Oil recovery factors for all studied scenarios.

Injection approach	Oil recovery factor (%OOIP)		
	All wells are horizontal	All wells are vertical	One horizontal producer and three vertical injectors
CO_2 injection into the reservoir	71.2	73.4	66.1
CO_2 injection into the aquifer	67.7	69.8	54.8
CO_2 injection assisted by waterflooding	28.1	25.3	18.2

for all cases, the maximum oil recovery is less than 30% of the OOIP indicating poor recovery performance. Injecting water could have resulted in the trapping of more oil. Also, CO_2 is in contact with less volume of oil. In this case, the minimum oil recovery is 18%, and the maximum recovery is around 28%, which was achieved using one horizontal injector and one horizontal producer. Overall, all cases of vertical and horizontal wells showed lower recovery compared to the cases where waterflooding was not implemented.

Comparative Analysis

The oil recovery for all studied scenarios (nine cases) is listed in **Table 1.** It should be noted that the same number of wells and configurations was used in the three main scenarios (CO_2 injection into the reservoir, CO_2 injection into the aquifer, and CO_2 injection into the aquifer assisted by waterflooding) in order to minimize the uncertainty of the simulation results. The highest oil recovery (73% of the OOIP) was obtained using CO_2 injection into the depleted reservoir and utilizing three vertical injectors and three vertical producers, while the minimum oil recovery (18% of the OOIP) was achieved for injecting CO_2 into the aquifer followed by waterflooding, where three vertical injectors and one horizontal producer were used. Also, injecting CO_2 into the aquifer without applying waterflooding showed a comparable oil recovery compared to the case of direct injection of CO_2 into the reservoir. The simulation results showed that the injected CO_2 will be stored within the reservoir and aquifer systems, as a small amount of CO_2 (around 12% of the injected volume) was produced. Around 80–90% of the injected CO_2 will be sequestered in the reservoir formations, and the produced gases can be re-injected into the reservoir. Utilizing a constant injection approach, the estimated volume of CO_2 that can be sequestered in the underground formations is around 7,928 tons, on average.

Moreover, the performance of CO_2 injection is compared to that of the conventional waterflooding treatment. **Figure 11** shows the oil recovery factor vs. time for CO_2 injection into the aquifer and waterflooding cases, where all wells are drilled horizontally. CO_2 injection showed considerably higher recovery compared to water flooding: 68 vs. 12% of the OOIP. The CO_2 approach outperforms water injection although one horizontal well was used for injecting CO_2, while two horizontal wells were used for water injection. Moreover, the injection of CO_2 into the aquifer provides dual benefits: CO_2 sequestration and attractive oil production. Injecting carbon dioxide into the aquifer results in slow release of CO_2, which will interact with the oil and reduce the oil viscosity.

FIGURE 11 | Oil recovery factor vs. time for CO_2 injection and waterflooding cases. All wells were drilled horizontally.
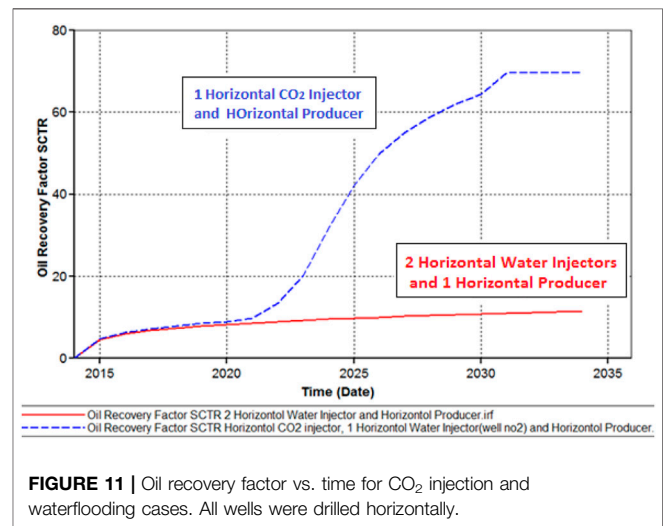
In this work, the geochemical reactions between the injected carbon dioxide and the reservoir/aquifer systems were not examined. Injecting CO_2 may alter the rock properties such as porosity and permeability, due to the geochemical reactions (Cui et al., 2021). Hence, it is recommended to conduct a geochemical study to assess the changes in the reservoir and aquifer properties. Moreover, the distance between the injection and production wells can significantly affect the oil recovery profiles. However, in this work, we did not change the well location, as the main objective of the current study is to compare the performance of three main scenarios (CO_2 injection into the reservoir, CO_2 injection into the aquifer, and CO_2 injection into the aquifer followed by water injection). Further studies can be carried out to assess the impact of well locations on oil recovery during different CO_2 injection approaches.

CONCLUSION

This work examines the performance of CO_2 injection in enhancing oil recovery from depleted reservoirs. The CMG (Computer Modeling Group) software package was used to investigate different injection scenarios. Based on the conducted simulations, the following conclusions can be drawn:

- The highest oil recovery of 73% of the original oil-in-place (OOIP) was obtained by injecting CO_2 into the reservoir, utilizing vertical injectors and producers.
- During EOR treatments, around 7,928 tons of carbon dioxide can be sequestered in the reservoir/aquifer systems, on average.
- Injecting CO_2 into the water zone showed a very successful approach and enhanced the oil recovery by around 68–70% of the OOIP.
- In all studied cases, using horizontal produces and injectors gave more oil recovery than that using vertical wells, under the same conditions.
- CO_2 injection outperformed conventional waterflooding, where 68 and 12% of the OOIP were recovered, respectively.
- Overall, injection of CO_2 into the depleted reservoir can provide dual benefits of CO_2 sequestration and enhanced oil recovery.
- Further work can be conducted to evaluate the geochemical interactions and assess the impact of wells' locations on the oil recovery profiles.

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DATA AVAILABILITY STATEMENT

The original contributions presented in the study are included in the article/Supplementary Material, further inquiries can be directed to the corresponding authors.

AUTHOR CONTRIBUTIONS

MA performed the work and wrote the original draft. AH analyzed the data and prepared the manuscript. AH, SP, and MM validated the results. MM supervised the work. NS helped in the simulation work. SP and MM reviewed the manuscript.

ACKNOWLEDGMENTS

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