Engineering 18 (2022) 79–87

Contents lists available at ScienceDirect

Engineering

journal homepage: www.elsevier.com/locate/eng

Research
Unconventional and Intelligent Oil & Gas Engineering—Article

A Storage-Driven CO_2 EOR for a Net-Zero Emission Target

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A R T I C L E I N F O

Article history:
Received 8 December 2021
Revised 18 January 2022
Accepted 10 February 2022
Available online 22 March 2022

Keywords:
CO_2 EOR
Net CO_2 emissions
Dimethyl ether
Storage-driven CO_2 EOR
CO_2 sequestration

A B S T R A C T

Stabilizing global climate change to within 1.5 °C requires a reduction in greenhouse gas emissions, with a primary focus on carbon dioxide (CO_2) emissions. CO_2 flooding in oilfields has recently been recognized as an important way to reduce CO_2 emissions by storing CO_2 in oil reservoirs. This work proposes an advanced CO_2 enhanced oil recovery (EOR) method—namely, storage-driven CO_2 EOR—whose main target is to realize net-zero or even negative CO_2 emissions by sequestrating the maximum possible amount of CO_2 in oil reservoirs while accomplishing the maximum possible oil recovery. Here, dimethyl ether (DME) is employed as an efficient agent in assisting conventional CO_2 EOR for oil recovery while enhancing CO_2 sequestration in reservoirs. The results show that DME improves the solubility of CO_2 in *in situ* oil, which is beneficial for the solubility trapping of CO_2 storage; furthermore, the presence of DME inhibits the "escape" of lighter hydrocarbons from crude oil due to the CO_2 extraction effect, which is critical for sustainable oil recovery. Storage-driven CO_2 EOR is superior to conventional CO_2 EOR in improving sweeping efficiency, especially during the late oil production period. This work demonstrates that storage-driven CO_2 EOR exhibits higher oil-in-place (OIP) recovery than conventional CO_2 EOR. Moreover, the amount of sequestrated CO_2 in storage-driven CO_2 EOR exceeds the amount of emissions from burning the produced oil; that is, the sequestrated CO_2 offsets not only current emissions but also past CO_2 emissions. By altering developing scenarios, such as water alternating storage-driven CO_2 EOR, more CO_2 sequestration and higher oil recovery can be achieved. This work demonstrates the potential utilization of DME as an efficient additive to CO_2 for enhancing oil recovery while improving CO_2 storage in oil reservoirs.

1. Introduction

As humanity's dependence on fossil fuel is steadily increasing, our extensive utilization of fossil energy has led to proliferating carbon dioxide (CO_2) emissions [1,2]. It has been reported that anthropogenic CO_2 emissions reached 330 billion tonnes in 2021, more than three-quarters of which came from the combustion of fossil fuels [1,3,4]. Global climate change due to CO_2 emissions has become a serious environmental issue all over the world that cannot be ignored [5,6]. Over the past few decades, abundant CO_2 has been stored in deep saline aquifers at a global scale due to the simplicity of implementation [7–9]. Recently, depleted oil and gas reservoirs have been noted as ideal geological bodies for CO_2 storage, since the necessary infrastructure including ground facilities, injection wells, and transporting pipelines—in addition to well-known geological characteristics—already exists [10–13]. When injected into depleted oil and gas reservoirs, CO_2 can be used as a replacement agent that results in additional oil and gas recovery, which may offset a portion of the cost used for CO_2 capture and storage [14–16].

In addition to these types of storage, CO_2 is employed for oil recovery due to its superiority in improving fluid properties under oil reservoir conditions. The basic mechanism of CO_2 enhanced oil recovery (EOR) lies in the interfacial tension (IFT) deduction, oil viscosity reduction, oil swelling, and extraction effect on lighter hydrocarbon components [17–24]. Compared with other typical gases, such as natural gas, air, nitrogen (N_2), and so forth, CO_2 exhibits lower minimum miscible pressures (MMP) with the *in situ* oil; thus, CO_2 is considered to be a better candidate to achieve miscible flooding, which is deemed to be the most efficient method for oil recovery

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https://doi.org/10.1016/j.eng.2022.02.010
2095-8099/

[25]. It has been reported that the first commercial CO_2 flooding project, which was invested in by Chevron (USA), was implemented on the Kelly-Snyder oilfield of SACROC in Texas in 1981 [26]. With the maturation of CO_2 EOR technology in conventional reservoirs, hundreds of CO_2 projects have been implemented all over the world as of 2021, contributing more than 300 000 barrels (bbl; bbl = 158.9873 L) per day of accumulated oil production in the United States alone [27]. Based on technological development in horizontal-well and multi-stage hydraulic fracturing, CO_2-based strategies are being employed for tight oil recovery [28–31]. Extensive work has been conducted to investigate the mechanism of CO_2 EOR in increasing tight oil recovery [32–35]. Some studies have claimed that CO_2 EOR is inefficient in tight reservoirs as a result of the early occurrence of serious gas breakthrough, which is due to the presence of complex fractures in these reservoirs [36–38].

Water alternating gas flooding makes it possible to control the mobility ratio, and has been shown to have better sweeping and displacing efficiency than the single CO_2 EOR method [39–41]. Within this scenario, water is injected intermittently, successfully preventing early gas breakthrough [42]. Previous studies have comprehensively investigated the key factors affecting water alternating gas flooding, including the number of cycles performed, slug ratio, and slug size [43]. The main controlling parameter—that is, soaking time, which is important for mass transfer between CO_2 and the *in situ* oil—has been discussed in more depth in studies on tight reservoirs than in studies on conventional reservoirs [44–48].

In addition to oil recovery, the CO_2 EOR process holds potential for storing large amounts of CO_2 in reservoirs, thereby alleviating the greenhouse effect [49–53]. The first project involving CO_2 EOR and storage was implemented in the Weyburn oilfield in Canada in 2000 [54–57], which has a storage capacity of more than 25 million tonnes of CO_2 [58]. Geological storage of CO_2 has recently become a hot topic in the fossil fuel industry. The fundamental mechanism of CO_2 storage involves mineral trapping, solubility trapping, residual trapping, and structural trapping [59]. Recent studies have addressed the co-optimization of oil recovery and CO_2 storage, although most research has only analyzed very limited data and simple cases [60–67]. Thus, technical challenges remain in the co-optimization of CO_2 EOR and storage in oil reservoirs. For example, some phenomena during CO_2 EOR and storage negatively affect the final oil recovery and CO_2 sequestration capacity, including CO_2 override, gravity segregation, and viscosity fingering [68,69]. In future, more research attention should be paid to the basic mechanism of CO_2 EOR and storage in reservoirs, and new strategies should be inspired to maximize oil recovery and CO_2 storage capacity.

This work proposes a new generation of the CO_2 EOR method—namely, storage-driven CO_2 EOR—whose purpose is to realize net-zero or even negative CO_2 emissions by sequestrating CO_2 in oil reservoirs while maximizing oil recovery. Here, dimethyl ether (DME) is used as a novel agent to assist CO_2 EOR in enhancing oil recovery while improving CO_2 storage in oil reservoirs. This paper illustrates the fundamental mechanism of the storage-driven CO_2 EOR method and is expected to inspire new insights into CO_2 EOR; that is, the future CO_2 EOR should not only focus on a single target (i.e., oil recovery) but also focus on how to create the maximum CO_2 storage capacity in oil reservoirs.

2. Modeling approach

The efficiency of storage-driven CO_2 EOR was numerically investigated in order to enhance oil recovery and CO_2 storage in the Weyburn reservoir. The Weyburn reservoir, located in southeast Saskatchewan, Canada, has a depth of 1310–1500 m [70]. The reservoir temperature and pressure are 336.15 K and 14.0 MPa, respectively. The averaged reservoir permeability, porosity, and initial oil saturation are 20.0 mD, 30%, and 0.8, respectively, with a permeability that is isotropic in all directions. Components in the reservoir fluid can be lumped into 12 pseudo components, according to Pedersen's weight-based grouping [71]. A correlation from the previous work [71] is used to estimate the critical properties of the reservoir fluids, which are a function of the molecular weight and density. The Computer Modeling Group (CMG) WinProp's regression tool is used to tune this correlation by setting the fluid properties according to the original reservoir conditions. Table 1 presents the matched results between the fluid sample and the correlation, validating the reliability of this correlation. The physical properties of the Weyburn reservoir fluids and the binary interaction coefficients of each component are shown in Tables S1 and S2 in the Appendix A. The relative permeability of the oil reservoir was obtained from the Ref. [72].

Reservoir simulation is performed using the compositional simulator in CMG–GEM. A two-dimensional model is developed using the reservoir and the physical properties of the fluid sample in Table 1. The simulated reservoir has a grid dimension of $50 \times 50 \times 1$, with the dimensions of 2500, 2500, and 20 ft (1 ft = 0.3048 m) in the *x*, *y*, and *z* directions, respectively. The injector is located at block 1 on the left edge of the simulated reservoir, and the producer is located at the other edge of the simulated reservoir. The bottomhole pressure is held at 10.0 MPa in the producer, and the gas injection rate is maintained at a constant rate of 700 $m^3 \cdot d^{-1}$. The total simulation time is set as 10 years. In this work, both conventional CO_2 EOR and storage-driven CO_2 EOR are performed for the Weyburn reservoir with a fixed DME concentration of 20.0 mol%. In addition, to further evaluate the reliability of this numerical model, slim-tube test simulations are used to calculate the miscible pressure between CO_2 and the oil sample. The pressure was found to be very close to the experimental data, at around 14.0 MPa compared with 14.2 MPa [70], for a relative deviation of –1.41%.

3. Phase property measurement

Fig. 1 provides a schematic diagram for measuring the phase composition and CO_2 solubility in crude oil using a pressure–volume–temperature (PVT) setup. The viscosity, density, swelling factor, and saturation pressure of the experimental oil sample are 1.81 mPa·s, 810 $kg \cdot m^{-3}$, 1.072 $m^3 \cdot m^{-3}$, and 4.90 MPa, respectively, which are similar to those of the simulated oil used in the numerical model. Firstly, crude oil is introduced into the PVT cell at a given temperature and pressure. DME with a given molar concentration is then injected at a higher pressure. CO_2 is hereafter introduced into the PVT cell at the same temperature. The crude oil–DME–CO_2 mixture is pressed into a single phase under high-pressure conditions.

Gas chromatography (GC) is used to measure the composition of the crude oil–DME–CO_2 mixtures. Next, the system pressure is reset to the experimental pressure and held for at least 24 h, until the system reaches equilibrium. GC analysis is then used to measure the composition of the gas and oil phase in order to analyze the CO_2 solubility in crude oil by opening the valve connected to the PVT cell. Such a setup can withstand pressures of up to 100 MPa and temperatures as high as 473.15 K. The uncertainty in temperature and pressure measurement is controlled to within ± 0.5 K and ± 0.1 MPa, respectively, while the solubility uncertainty is around ± 0.5%.

4. Results and discussion

4.1. Solubility of CO_2 in crude oil

The solubility of CO_2 in crude oil is critical for the performance of a CO_2 EOR project for enhanced oil recovery and CO_2 storage.

Table 1
Physical properties of the Weyburn reservoir fluids [70].

	Saturation pressure (MPa)	Viscosity (mPa·s)	Density (kg·m^{-3})	Swelling factor (m^3·m^{-3})	Gas–oil ratio (m^3·m^{-3})
Sample	4.92	1.76	806.4	1.085	32
Correlation	4.92	1.76	805.8	1.089	32
Relative error (%)	0	0	−0.07	0.37	0

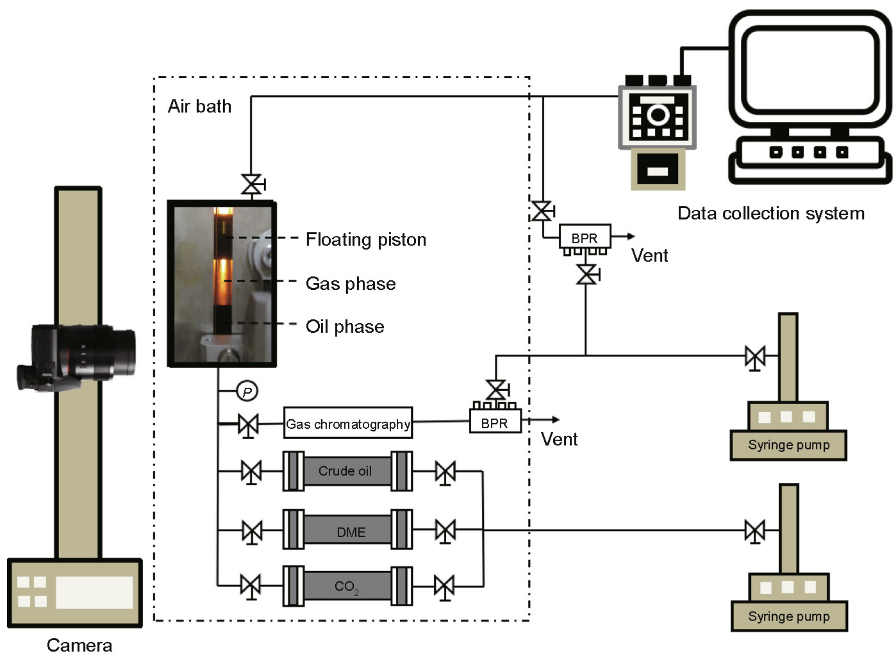

Fig. 1. Schematic diagram for measuring the phase composition and solubility of CO_2 in crude oil using the PVT setup. BPR: back pressure regulator; *P*: pressure.

Fig. 2 presents the CO_2 solubility in crude oil when DME is introduced under different pressure conditions. It is found that the solubility of CO_2 is highly influenced by the system pressure; that is, more CO_2 is dissolved as the pressure increases. More interestingly, DME significantly facilitates CO_2 solubility in the crude oil, especially under high-pressure conditions (> 4 MPa); the solubility is further improved as more DME is added. When DME is introduced, the DME molecules tend to form hydrogen bonds with the hydrocarbon carbon chains; this induces the rearrangement of the long carbon chains into a more regular and orderly arrangement, which beneficial for CO_2 dissolution in the *in situ* oil. In addition, the improved CO_2 solubility enables more CO_2 to be trapped in the *in situ* oil, which is essential for CO_2 storage in oil reservoirs.

Fig. 3 presents the molar fraction of the lighter components—that is, C_1–C_5—in the gas phase for the CO_2–crude oil and CO_2–DME–crude oil mixtures at different temperatures. To validate the reliability of this simulation model, we compare the prediction results from the simulation model with the experimental data. It is found that the predicted results agree well with the experimental data, suggesting that our simulation model is reliable. As shown in Fig. 3, the molar fraction of the lighter hydrocarbons increases in the gas phase as the temperature increases, indicating that a

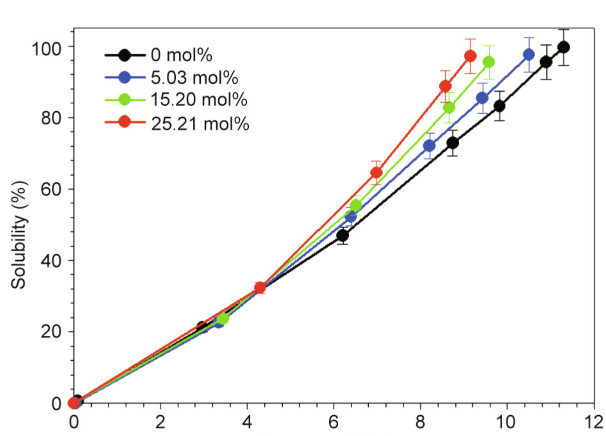

Fig. 2. CO_2 solubility in crude oil as a function of pressure and DME concentration.

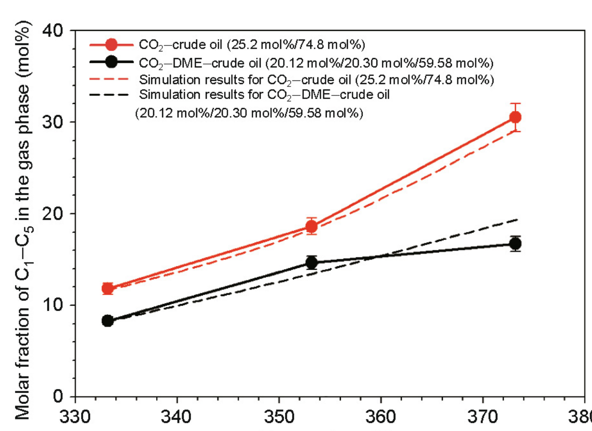

Fig. 3. Molar fraction of the lighter components (C_1–C_5) in the gas phase for CO_2–crude oil and CO_2–DME–crude oil mixtures at different temperatures.

greater amount of lighter hydrocarbons is extracted by CO_2 at higher temperatures. In addition, the molar fraction of the lighter hydrocarbons in the gas phase of the CO_2–DME–crude oil mixture is smaller than that of the CO_2–crude oil mixture. This finding suggests that the extraction effect on the lighter components is greatly inhibited when DME is introduced, especially under high-temperature conditions. When a CO_2 EOR project is implemented in a reservoir, the CO_2 dissolves into the *in situ* oil, and the lighter components in the crude oil tend to "vaporize" into the gas phase due to the CO_2 extraction effect. However, with the addition of DME, most of the lighter hydrocarbons remain "fixed" in the oil phase, which favors sustainable oil recovery.

4.2. Improved oil recovery

The superiority of DME in improving CO_2 solubility gives it the potential to enhance oil recovery while assisting CO_2 storage in oil reservoirs. In this section, the performance of traditional CO_2 EOR is compared with that of storage-driven CO_2 EOR to evaluate the potential of DME for enhancing oil recovery. Fig. 4 illustrates oil recovery in terms of the production time for conventional CO_2 EOR and storage-driven CO_2 EOR at different gas injection rates. As shown in Fig. 4, oil recovery increases linearly during the initial stage of a conventional CO_2 EOR project, until CO_2 is produced from the production wells (around 1200 d). Furthermore, it seems that the gas injection rate does not affect oil recovery during the early oil production period. After gas breakthrough, oil recovery increases with an increasing gas injection rate; it then tends to level off and less oil is produced. After introducing DME, the initial oil recovery is increased; during the late oil production period, oil recovery increases continuously, indicating that storage-driven CO_2 EOR favors sustainable oil recovery.

Fig. 5 presents digital images of oil saturation in reservoirs for conventional CO_2 EOR and storage-driven CO_2 EOR at a pore volume (PV) of 0.5. In the dominating channel, a large proportion of the *in situ* oil is displaced, leading to relatively lower oil saturation. In conventional CO_2 EOR, the oil saturation in the dominating channel is still higher than 0.40; in comparison, after introducing DME, additional oil is mobilized and the oil saturation in the dominating channel is generally lower than 0.32. Conventional CO_2 flooding exhibits less sweep efficiency in oil reservoirs, resulting in a large portion of the *in situ* oil being untouched, whereas storage-driven CO_2 EOR is superior in expanding the sweeping efficiency and thereby enhancing oil recovery.

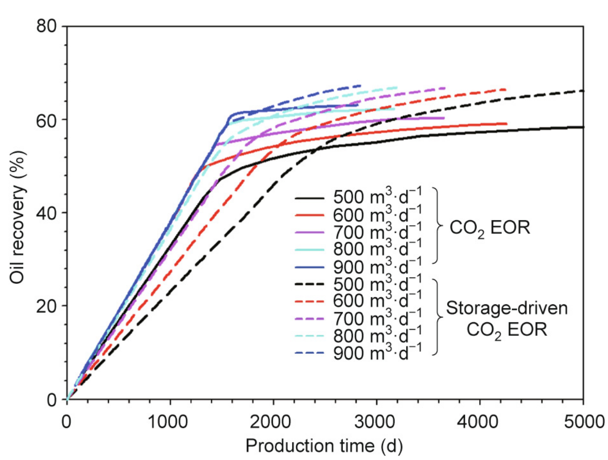

Fig. 4. Oil recovery in terms of the production time for conventional CO_2 EOR and storage-driven CO_2 EOR at different gas injection rates.

Water alternating gas injection is performed with the purpose of further enhancing oil recovery. Fig. 6 depicts oil recovery as a function of the production time for water alternating gas injection at different bottomhole pressures. The solid lines in the figure represent water alternating CO_2 EOR, while the dotted lines represent water alternating storage-driven CO_2 EOR. As shown in Figs. 4 and 6, water alternating gas EOR generally yields higher oil recovery than conventional gas flooding. The viscosity of the liquid-like CO_2 is very small, resulting in an unstable contacting front and gravity separation when injected; such behavior makes CO_2 EOR inefficient. However, water alternating gas EOR overcomes these shortcomings and is therefore superior for the recovery of oil-in-place (OIP). As shown in Fig. 6, oil recovery for water alternating storage-driven CO_2 EOR is higher than that for water alternating CO_2 EOR during the late oil production period. This finding indicates that water alternating storage-driven CO_2 EOR achieves sustainable oil recovery.

4.3. Improved CO_2 storage

In this section, the influence of DME on CO_2 storage during CO_2 EOR is specially investigated. Fig. 7 presents the CO_2 storage ratio according to the oil production time for conventional CO_2 EOR and storage-driven CO_2 EOR, where the CO_2 storage ratio is defined as the ratio of the sequestrated CO_2 to the total injected CO_2. During the initial oil production period (< 1200 d), the oil reservoir has an extremely high CO_2 geological storage capacity at low gas injection rates. During the late oil production period, the CO_2 becomes increasingly saturated in the residual oil, rock pore spaces, and so forth, resulting in decreasing CO_2 storage efficiency. In both injection scenarios, the CO_2 storage ratio decreases as the gas injection rate increases. Gas figuring readily occurs and a large proportion of the injected CO_2 flows through the dominating channels when the gas injection rate is high, resulting in decreased CO_2 storage efficiency in reservoirs. As shown in Fig. 7, the CO_2 storage ratio for storage-driven CO_2 EOR is significantly higher than that for conventional CO_2 EOR under the same conditions (i.e., the same gas injection rate and production time). Thus, it can be reasonably inferred that DME can be used as a favorable agent to improve CO_2 storage in oil reservoirs.

The CO_2 storage ratio is then obtained for a scenario involving the water alternating gas injection method. Fig. 8 presents the CO_2 storage ratio according to the oil production time for water alternating CO_2 EOR and water alternating storage-driven CO_2 EOR at different bottomhole pressures. In general, the water alternating gas injection method exhibits a higher CO_2 storage ratio than the conventional gas injection method (Figs. 7 and 8). The water alternating gas injection method overcomes gravity separation and the gas figuring effect, which is beneficial for increasing the sweep efficiency and CO_2 storage efficiency in oil reservoirs. As expected, water alternating storage-driven CO_2 EOR exhibits higher CO_2 storage efficiency in oil reservoirs than water alternating CO_2 EOR: as high as 0.95, even after 3000 d's production. Fig. 9 presents digital images of the ratio of free gas to dissolved CO_2 in the oil reservoir at a production time of 2000 d for both EOR scenarios, with a bottomhole pressure of 6.0 MPa. It can be seen that the quantity of dissolved CO_2 is higher than that of free-state CO_2. In both developing methods, the relative quantity of dissolved CO_2 gradually decreases as the production wells are approached. However, the presence of DME results in a lower ratio of free gas to dissolved CO_2; this indicates that DME improves the solubility trapping of CO_2 in the *in situ* oil, demonstrating the superiority of DME in enhancing oil recovery while assisting with CO_2 storage in reservoirs.

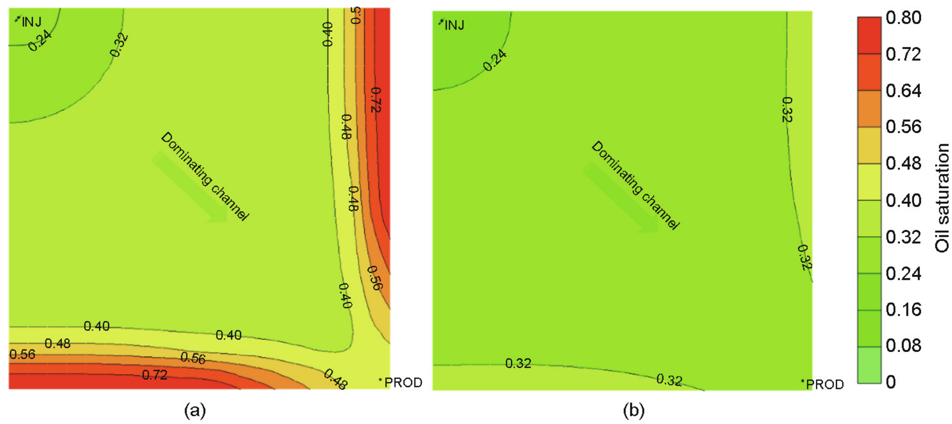

Fig. 5. Digital images of oil saturation in the reservoir for (a) conventional CO_2 EOR and (b) storage-driven CO_2 EOR at 0.5 PV. INJ: injection well; RPOD: production well.

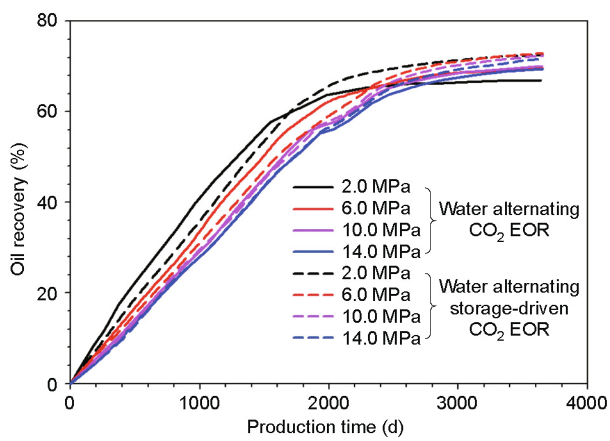

Fig. 6. Oil recovery in terms of the production time for water alternating gas injection at different bottomhole pressures.

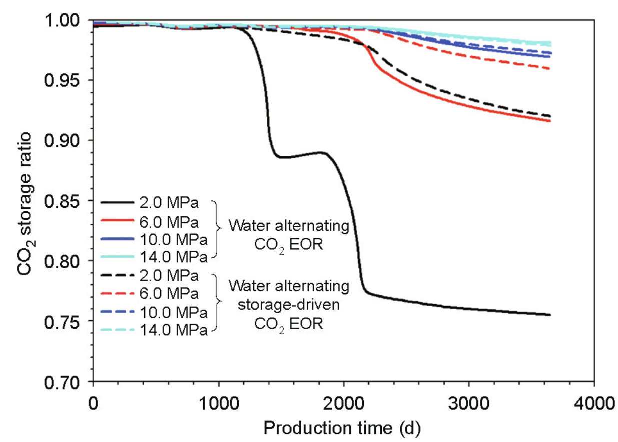

Fig. 8. CO_2 storage ratio versus oil production time for water alternating CO_2 EOR and water alternating storage-driven CO_2 EOR at different bottomhole pressures.

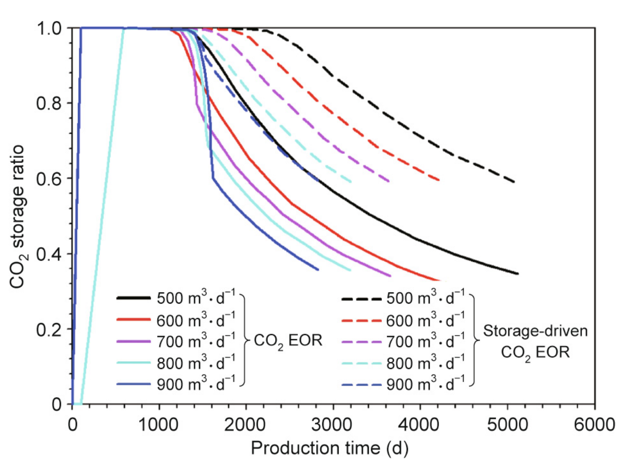

Fig. 7. CO_2 storage ratio versus oil production time for conventional CO_2 EOR and storage-driven CO_2 EOR at different gas injection rates.

4.4. Economics and operations of storage-driven CO_2 EOR

The concept of storage-driven CO_2 EOR is proposed for this first time in this work, with the aim of realizing net-zero or even negative CO_2 emissions by sequestrating CO_2 in oil reservoirs while maximizing oil recovery. Here, net CO_2 emissions are defined as the difference between the CO_2 emissions from burning the produced oil (approximately 0.0027 t$\cdot$bbl^{-1}) and the sequestrated CO_2 in oil reservoirs during conventional CO_2 EOR or storage-driven CO_2 EOR [73]. Primary and secondary production typically recover around 30% of the *in situ* oil from a reservoir. According to our simulation results, conventional CO_2 EOR achieves around 60% recovery of the OIP, while storage-driven CO_2 EOR and water alternating storage-driven CO_2 EOR has the technical potential to increase OIP recovery to approximately 68% and 73%, respectively. The economics of CO_2 EOR projects greatly depend on the cost of the CO_2 source and the oil price over the project's lifetime [73]. Here, we take a hypothetical oilfield with 200 million barrels OIP as an example, as described in Table 2.

After primary and secondary production, it is assumed that conventional CO_2 EOR, storage-driven CO_2 EOR, and water alternating storage-driven CO_2 EOR are respectively implemented in the hypothetical oilfield for oil production. Here, "storage-driven CO_2 EOR" refers to DME-assisted CO_2 EOR, and "water alternating storage-driven CO_2 EOR" refers to water alternating DME-assisted CO_2 EOR.

Fig. 10 illustrates the net CO_2 emitted from the incremental production and the net CO_2 emissions as a function of the cumulative oil production over the lifetime of an oilfield. During primary and secondary production, CO_2 emissions increase linearly with increasing oil production. When conventional CO_2 EOR begins, a proportion of the injected CO_2 is sequestrated in the reservoir, offsetting part of the incremental CO_2 emissions from the oil burning. In comparison, when using storage-driven CO_2 EOR, the sequestrated CO_2 exceeds the CO_2 emissions from oil burning; that is,

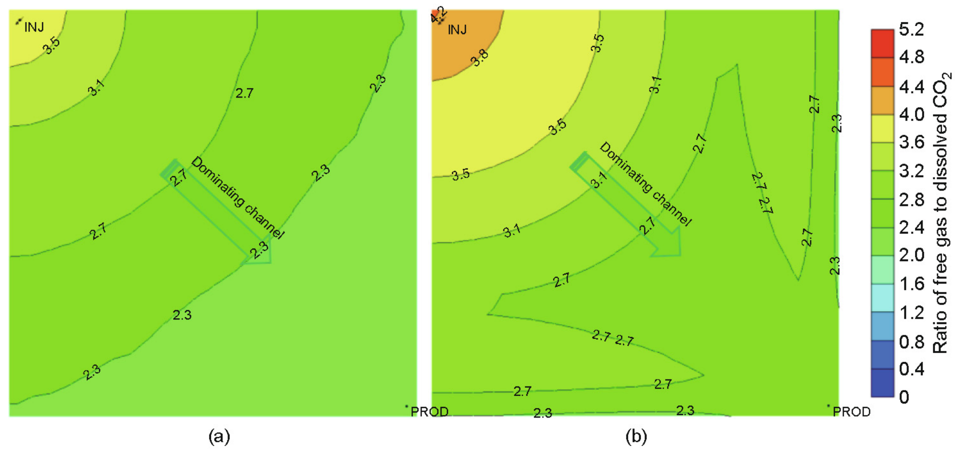

Fig. 9. Digital images of the ratio of free gas to dissolved CO_2 in an oil reservoir when the production time is 2000 d for (a) water alternating storage-driven CO_2 EOR and (b) water alternating CO_2 EOR, at a bottomhole pressure of 6.0 MPa.

Table 2
Assumptions and physical properties in the hypothetical analysis.

Development method	Total recovery (% OIP)	Total oil recovery (million barrels)	CO_2 EOR oil recovery (million barrels)	CO_2 injected (Mt)	CO_2 emitted on use (Mt)	Net CO_2 emitted (Mt)	CO_2 emitted from incremental production (Mt)	Net CO_2 emitted from incremental production (Mt)
Primary and secondary production	30	60	0	0	25.8	25.8	–	–
Conventional CO_2 EOR[a]	60	120	60	12	51.6	39.6	25.8	13.8
Storage-driven CO_2 EOR[b]	68	136	76	39	58.48	19.48	32.68	−6.32
Water alternating storage-driven CO_2 EOR[b]	73	146	86	51	62.78	11.78	36.98	−14.02

Note: the initial OIP is assumed to be 200 million barrels.
[a] At 2.5 $bbl\cdot t^{-1}$ CO_2.
[b] At 1.25 $bbl\cdot t^{-1}$ CO_2.

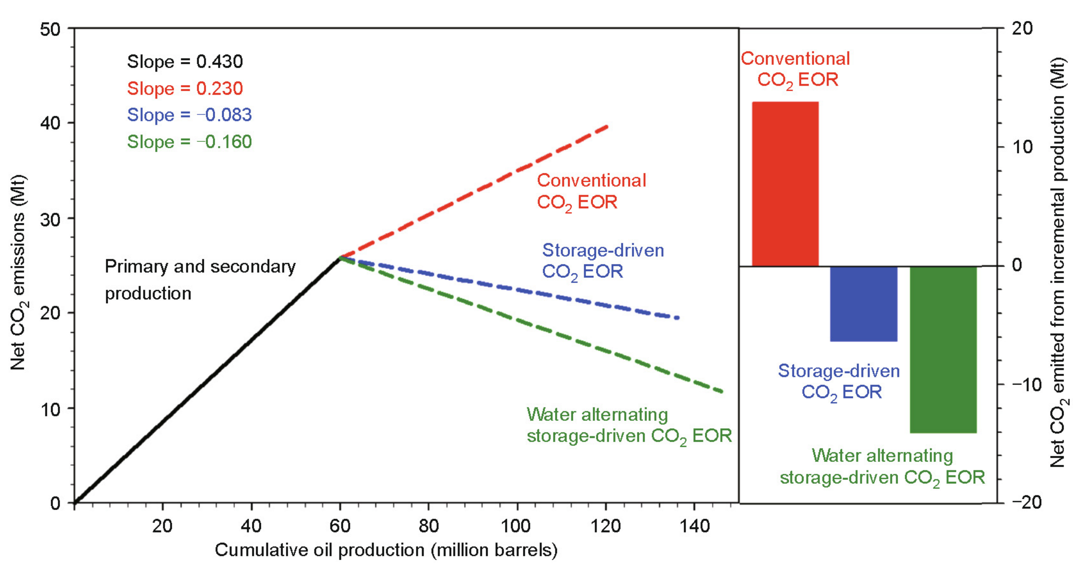

Fig. 10. Net CO_2 emitted from incremental production and net CO_2 emissions as a function of cumulative oil production over the lifetime of an oilfield.

the sequestrated CO_2 offsets not only the current CO_2 emissions but also some of the past CO_2 emissions, resulting in the linearly decreasing net CO_2 emissions shown in Fig. 10. In a further comparison, when using water alternating storage-driven CO_2 EOR, even more CO_2 is sequestrated in the reservoir, resulting in a greater decrement in the net CO_2 emissions from incremental oil production. As shown in Fig. 10 (right), the net CO_2 emitted from incremental production is 13.8 Mt with conventional CO_2 EOR, while the net CO_2 emissions with storage-driven and water alternating storage-driven CO_2 EOR are both negative, at −6.32 and −14.02 Mt, respectively. These results indicate that the CO_2 sequestrated when using storage-driven and water alternating storage-driven CO_2 EOR far exceeds the net CO_2 emitted from incremental production, suggesting that storage-driven CO_2 EOR is a promising way to achieve a win-win scenario for both oil production and CO_2 sequestration.

Table 3
Economic analysis of conventional CO_2 EOR and storage-driven CO_2 EOR.

Oil price ($USD\cdot bbl^{-1}$)		CO_2 acquisition cost ($USD\cdot t^{-1}$)	CO_2 acquisition cost ($USD\cdot bbl^{-1}$ production)	Other related costs ($USD\cdot bbl^{-1}$)	Net pretax margin ($USD\cdot bbl^{-1}$)	CO_2 EOR production (million barrels)	EOR project margin (million USD)	CO_2 injected (Mt)	CO_2 price to break even ($USD\cdot Mt^{-1}$)	Project margin (million USD)[a]
Conventional CO_2 EOR[b]	80	−39	−15	−35	30	60	1800	12	–	–
	60	−29	−12	−35	13	60	780	12	–	–
	40	−19	−8	−35	−3	60	−180	12	–	–
Storage-driven CO_2 EOR[c]	80	−39	−31	−56	−7	76	−532	39	60	638
	60	−29	−23	−56	−19	76	−1444	39	57	−274
	40	−19	−15	−56	−31	76	−2356	39	56	−1186
Water alternating storage-driven CO_2 EOR[c]	80	−39	−25	−45	10	86	860	51	18	2390
	60	−29	−15	−45	0	86	0	51	15	1530
	40	−19	−10	−45	−15	86	−1290	51	22	240

[a] If credited with the social cost of carbon (30 $USD\cdot t^{-1}$) for incremental storage.
[b] At 2.5 $bbl\cdot t^{-1}$ CO_2.
[c] At 1.25 $bbl\cdot t^{-1}$ CO_2.

The economics of CO_2 EOR projects strongly depend on the price of oil, cost of CO_2 acquisition, other costs associated with the CO_2 EOR, and so forth [73]. Table 3 presents an economic analysis of conventional CO_2 EOR and storage-driven CO_2 EOR. "Low," "reference," and "high" oil prices are assumed to be 40, 60, and 80 $USD\cdot bbl^{-1}$, respectively, over the life of the EOR project. The economic analysis also considers the CO_2 acquisition cost and other related costs. Even though the oil production from storage-driven CO_2 EOR is higher than that from conventional CO_2 EOR, the EOR project margin of the former is smaller than that of the latter. When the EOR scenarios are adjusted, it can be seen that storage-driven CO_2 EOR—and particularly water alternating storage-driven CO_2 EOR—yields the greatest EOR project margin. The project margins are sensitive not only to the oil price but also to the CO_2 acquisition cost, the imposed charge on CO_2 emissions, and so forth [73]. In other words, without an imposed charge on CO_2 emissions, the implementation of storage-driven CO_2 EOR may not be financially attractive to investors. Our analysis reveals that the additional costs required in order for storage-driven CO_2 EOR to break even with conventional CO_2 EOR range from 15 to 22 $USD\cdot Mt^{-1}$ for water alternating storage-driven CO_2 EOR and from 56 to 60 $USD\cdot Mt^{-1}$ for storage-driven CO_2 EOR.

5. Conclusions

This work proposes a storage-driven CO_2 EOR method involving the application of DME as an additive to CO_2 in order to improve oil recovery while assisting CO_2 storage in oil reservoirs. The main conclusions are as follows:

Test results show that the introduction of DME greatly inhibits the "escape" of lighter components from the crude oil, especially under high-temperature conditions; in addition, DME improves CO_2 solubility in crude oil, especially under high-pressure conditions (> 4 MPa).

Simulation results show that storage-driven CO_2 EOR is superior to conventional CO_2 EOR in expanding the sweeping efficiency, which greatly increases oil recovery, especially during the late oil production period. This finding suggests that DME favors sustainable oil recovery by assisting conventional CO_2 EOR. Furthermore, when the development scenarios are transformed to involve water alternating gas injection, oil recovery is more enhanced in comparison with scenarios involving gas injection methods.

Storage-driven CO_2 EOR provides a higher CO_2 storage ratio in oil reservoirs than conventional CO_2 EOR. When water alternating gas injection is used, the CO_2 storage ratio is further improved. This finding suggests that DME can be used as a favorable agent with CO_2 to improve oil recovery while assisting with CO_2 storage in oil reservoirs.

The sequestrated CO_2 from storage-driven CO_2 EOR exceeds the CO_2 emissions that result from burning the produced oil; thus, the sequestrated CO_2 offsets not only current CO_2 emissions but also past emissions. Furthermore, water alternating storage-driven CO_2 EOR sequestrates even more CO_2 in reservoirs than storage-driven CO_2 EOR. Nevertheless, the implementation of storage-driven CO_2 EOR may not be financially attractive to investors compared with conventional CO_2 EOR without any other imposed charge on CO_2 emissions.

Acknowledgments

We acknowledge the financial support from the Science Foundation of China University of Petroleum, Beijing (2462021QNXZ012 and 2462021YJRC012). This research is also supported by the Fundamental Research Funds for the Central Universities.

Compliance with ethics guidelines

Yueliang Liu and Zhenhua Rui declare that they have no conflict of interest or financial conflicts to disclose.

Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.eng.2022.02.010.

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