14th International Conference on Greenhouse Gas Control Technologies, GHGT-14

21st -25th October 2018, Melbourne, Australia

A Comparative Study of CO_2-flood Displacement Efficiency for Different CO_2 Injection Strategies: Permian Basin vs. U.S. Gulf Coast

P. Hosseininoosheri, S.A. Hosseini, V. Nunez-Lopez, L.W. Lake

The University of Texas at Austin, Austin, Texas, USA

Abstract

In CO_2-EOR, there are two main field development strategies: water-alternating-gas (WAG) and continuous gas injection (CGI). The aim of our study is to compare these strategies in terms of their economic performance (from the basis of incremental oil recovery) and in terms of their environmental performance (from the basis of ultimate CO_2 storage volumes). Within this framework and to demonstrate the efficiency of each strategy, we evaluate the distribution of Carbon Dioxide in oil, gas, and brine phases; the amount of total CO_2 stored at the end of the project; the incremental oil recovery; and the CO_2 utilization ratios. In this study, we model and compare two fields which represent two different reservoir settings: Cranfield (representative of the U.S. Gulf Coast sandstone reservoirs) and SACROC (representative of the Permian Basin carbonate reservoirs). CGI is the original operating strategy in Cranfield and WAG is the original operating strategy applied in the SACROC unit.

High resolution geocellular models are used for both Cranfield and SACROC fields. The models are constructed based on wire-line logs, seismic surveys, core data, and stratigraphic interpretations. A comprehensive pressure-production history matching for primary, secondary, and tertiary recovery is conducted for both of the fields. Different operating strategies are designed for each field (e.g. CGI and WAG). After finishing the history-matching, CGI and WAG scenarios are simulated in both models to compare their performances. CO_2 partitioning in oil, brine, and gas phase (mobile or residual) are compared for both scenarios (WAG and CGI). The partitioning of CO_2 in oil results in CO_2 miscibility in oil, the partitioning of CO_2 in brine results in CO_2 dissolution in brine, and CO_2 partitioning in gas phase are divided into structural trapping and residual trapping of CO_2. We plotted the contribution of different trapping mechanisms over a post injection period for WAG and CGI for both SACROC and Cranfield. Additionally, the total CO_2 storage, the incremental oil recovery, and CO_2 utilization ratios are compared in both scenarios for both fields.

Although actual operating strategy in these two fields are different (CGI in Cranfield and WAG in SACROC), our numerical modelling results show that WAG could not only balance the CO_2 storage, incremental oil recovery, and CO_2 utilization ratio but also store the trapped CO_2 with lower risk of leakage in both fields (by decreasing the amount of structurally trapped CO_2). Because of multiple alternation of CO_2 and water slugs in WAG, this approach reduces the viscous instability and therefore the efficiency of oil recovery. Our study shows that the distribution of CO_2 in different phases is different for each field. Because of the lower minimum miscibility pressure (MMP) and lighter initial oil saturation in SACROC, the partitioning of CO_2 in oil is much higher in SACROC than in Cranfield. The dissolution of CO_2 in brine is much higher in Cranfield because of the presence of strong aquifer near injection wells.

The present work provides valuable insights for optimizing oil production and CO_2 storage in a CO_2-EOR

project. Additionally, this study clearly shows the impact of development strategies on the relative importance of different trapping mechanisms.

Keywords: CO_2 EOR; CO_2 storage; CO_2 trapping mechanisms; CCSIntroduction

1. Introduction

Global emissions of carbon dioxide (CO_2) exceed 35 Gt/year (IPCC, 2014) and the US contributes 6.5 Gt/year (United States Environmental Protection Agency, 2018). To reduce this number, carbon capture and storage (CCS) has been brought to the fore as a fossil fuel emission mitigation tool and greater attention is being paid to the potential for CO_2-EOR to support geological CO_2 storage. CO_2-EOR offers commercial opportunities to improve oil recovery from mature oil fields while offering a permanent storage option for large CO_2 volumes. Such a dual-nature process represents a technically attractive and potentially economic way to spur greater CCS action. In other words, by performing additional site characterization and risk assessment tasks, employing reliable monitoring techniques, and revisiting the field abandonment practices, CO_2-EOR practices can be modified and tied to CCS projects to deliver significant capacity for long-term CO_2 storage.

In the area of CO_2–EOR/storage, one of the important issues is understanding and forecasting the CO_2 distribution over a geological time period. Successfully storing CO_2 during and after an EOR process depends on the ability of the storage site to sequester the CO_2. The main processes controlling the trapping of CO_2 during CO_2–EOR are stratigraphic trapping, residual trapping, solubility trapping, and mineral trapping (Riaz and Tchelepi, 2006; Hosseininoosheri et al., 2018 (a)). Stratigraphic trapping is the containment of supercritical CO_2 as a mobile phase due to permeability constrictions imposed by field-scale reservoir stratigraphy and structure. CO_2 usually traps under the impermeable zones of the reservoir, such as caprocks and sealing faults. Residual trapping refers to the entrapment of supercritical CO_2 in pores as an immobile phase because of capillary forces. Solubility trapping is the dissolution of CO_2 into reservoir fluids, including brine and oil. The solubility of CO_2 into brine depends on temperature, pressure, and salinity. Mineral trapping depends on CO_2 dissolution into brine. The dissolution of CO_2 in brine decreases the pH of the brine, which leads to a solubility increase of many minerals present in the formation rock. Therefore, CO_2 reacts directly and indirectly with minerals of the formation rock, leading to the precipitation of secondary **car**bonate minerals (Hosseini et al., 2018; Ampomah et al., 2016; Han, 2008; Xu et al., 2004). Fig. 1 shows the four main mechanisms that contribute to trapping the injected CO_2 in a hydrocarbon reservoir (Hosseininoosheri et al., 2018 (b)).

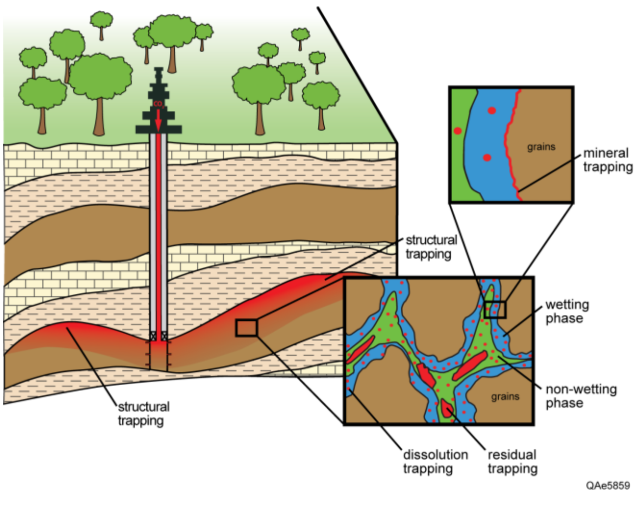


Fig. 1. CO_2 trapping mechanisms in a CO_2-EOR/storage process (Hosseininoosheri et al., 2018 (b)).

2. SACROC background

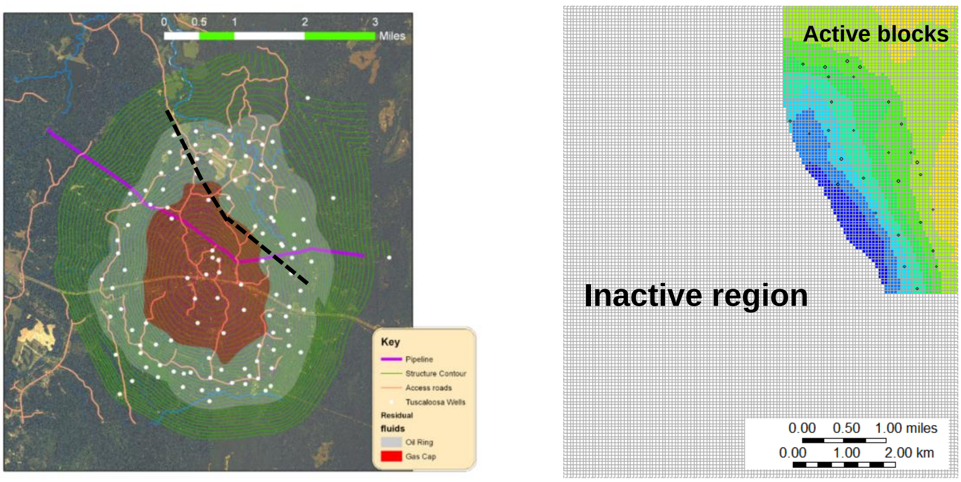
The Scurry Area Canyon Reef Operators Committee (SACROC) in Scurry County, West Texas, is located in the Horseshoe Atoll within Midland basin. (Ghahfarokhi et al., 2016). The Horseshoe Atoll is an icehouse carbonate reservoir. Icehouse carbonates are one of the least understood and documented carbonate reservoirs because of their high heterogeneity (Isdiken, 2013).The SACROC unit is classified into two major reservoir zones, Canyon and Cisco (Saneifar et al., 2016). The Wolfcamp shale formation of the lower Permian is the caprock above the Pennsylvanian Canyon and Cisco. Chevron Oil Co. was the first operator of the SACROC unit. They drilled the first well at a depth interval of 6,334 to 6,414 ft. in 1948. After that, the development of the unit was rapid and 1617 producing wells were drilled by 88 different operators by 1951. However, a huge pressure drop of 50% revealed that solution gas drive was the primary producing mechanism of the reservoir and no effective water drive existed. Therefore, to maintain the pressure level and improve the oil recovery, water injection started along the longitudinal axis of the crest of the reef called the “center-line” waterflood pattern in SACROC in 1954. Although the center-line waterflood improved the oil recovery, a large amount of the reserves still remained unswept. Hence, the SACROC Engineering Committee planned CO_2 injection into 202 inverted nine-spot patterns in 1968. Due to limited CO_2 supplies, three pilot areas were selected for initial flooding. The positive results encouraged the operators to start phase one of CO_2 injection in 1972. More than 175 Million metric tons of CO_2 has been injected into the SACROC unit and it is assumed that half of this amount has been sequestered in the field. Kinder Morgan (KM) purchased the SACROC unit in 2000 and installed the Centerline Pipeline to deliver an additional 300 MMSCFD of CO_2 to the field. Subsequent incremental oil recovery encouraged KM to expand their fully miscible CO_2 flood phase-by-phase from central area to outward. More details about reservoir specifications, production history, simulation projects, and monitoring efforts can be found in other works (Brummett et al., 1976; Dicharry et al., 1973; Schepers et al., 2007; Han et al., 2010; Yang et al., 2014; He et al., 2016).

3. Cranfield background

The investigation on the contribution of trapping mechanisms to CO_2 storage in/after a CO_2-EOR process has received little attention. The contribution of these trapping mechanisms to CO_2 storage depends on various reservoir’s static and dynamic parameters such as reservoir heterogeneities, caprock properties, CO_2-rock wettability, reservoir pressure and temperature, brine salinity, and hydrocarbon properties. While many geological properties cannot be changed in a specific reservoir, it has been shown that an intelligent selection of CO_2 injection strategy improves both the incremental oil recovery and CO_2 storage capacity. Water-alternating-gas (WAG) and continuous gas injection (CGI) are two main field development strategies in CO_2-EOR processes. Therefore, we investigated and discussed the partitioning of CO_2 among different phases (oil, gas, and brine) during and after two well-known CO_2 injection schemes using numerical multiphase flow simulations. We compare these strategies in terms of their economic performance (from the basis of incremental oil recovery) and in terms of their environmental performance (from the basis of ultimate CO_2 storage volumes). Within this framework and to demonstrate the efficiency of each strategy, we evaluate the distribution of Carbon Dioxide in oil, gas, and brine phases; the amount of total CO_2 stored at the end of the project; the incremental oil recovery; and the CO_2 utilization ratios. In this study, we model and compare two fields which represent two different reservoir settings: Cranfield (representative of the U.S. Gulf Coast sandstone reservoirs) and SACROC (representative of the Permian Basin carbonate reservoirs). CGI is the original operating strategy in Cranfield and WAG is the original operating strategy applied in the SACROC unit.

The Cranfield site is located on the Adams-Franklin county line in Mississippi, east of the town of Natchez (Weaver and Anderson, 1966). The original productive area of the reservoir was estimated to be 31.3 km^2 with a producing depth range of 3060 to 3193 m, a clastic reservoir located at the apex of a 4-way anticline in the Tuscaloosa Formation of Cretaceous age. Down dip an active aquifer provided pressure support. The initial reservoir temperature was reported 125°C with an initial reservoir pressure of 32.4 MPa at 3040 m. A sealing fault divides the productive zone into two compartments (the dashed NW-SE line in Fig. 2).

The first oil producing well was drilled in 1944. Since then, a productive area of about 7,750 acres has been defined by 93 producing wells. The oil wells were drilled based on a 40 acres spacing whereas the spacing for the gas wells was 320 acres. The dome-shaped reservoir consists of an oil ring overlain by a large gas cap. A cycling and extraction gas plant was used to reinject the produced gas from the Cranfield and deeper Paluxy reservoirs into the Tuscaloosa Formation. By 1951, the injected gas had reached many of the oil zone wells. The gas cycling continued until 1960 with dry gas sweeping the gas cap and the oil zone. Although the gas injection plans were meant to avoid, or slow down, the pressure depletion in the reservoir, reservoir pressure gradually fell below 27.6 MPa (4000 psi) causing water to encroach into the oil zone as the oil was produced. By the beginning of 1960, most of the wells had either a ~100% water cut or a GOR greater than 100,000 standard cubic feet per standard barrel (scf/STB) with an average field water cut equal to 88% and GOR equal to 85,000 scf/STB. The blow down of the gas cap started then. At the same time, water was produced in large volumes to prevent the aquifer from pushing the remaining oil into the gas cap and reinjected in other overlying formations. Gas injection stopped in 1964 when the project was near its economic limit. Production from the field was halted on 1966 and the reservoir was abandoned. This time period, from 1944 to 1966, corresponds to the conventional historical production interval. Over the next several decades, a strong water drive restored pressure to near-initial levels. In 2007, CO_2-EOR was initiated by Denbury Onshore, LLC to sweep the bypassed residual oil. Between 2008 and 2015, more than half of the oil ring (Fig. 2-a) was developed using a semi five-spot injection pattern with continuous CO_2 injection. Initial patterns started in the northern part of the field and continued clockwise around the oil ring. This time period correspond to the historical CO_2-EOR injection period. More details about reservoir specifications, production history, simulation projects, and monitoring efforts can be found in other works (Alfi and Hosseini, 2016; Alfi et al., 2015; Choi et al., 2011; Hosseini et al., 2013; Hovorka et al., 2013; Weaver and Anderson, 1966).



a) Cranfield site b) Simulation gridding

Fig. 2. Structural contour map at Cranfield (a); the black dashed line represents the sealing fault that separates the north-eastern section of the reservoir from the rest and reservoir simulation model to simulate the CO_2 injection process (b). Simulation effort is focused on the north-eastern side of the reservoir so the rest of the model is inactive to reduce the computational cost.

4. Model description

High resolution geocellular models are used for both Cranfield and SACROC fields. The models are constructed based on wire-line logs, seismic surveys, core data, and stratigraphic interpretations. The fluid flow of the study areas are simulated using GEM combined with WINPROP from Computer Modeling Group (CMG). WINPROP computes the thermodynamic properties of the reservoir fluids including bubble point pressure, solution gas-oil ratio, formation volume factor, and fluid viscosities (oil and gas).

The SACROC model consists of a 55×50×20 (x×y×z) Cartesian grid that has an area of 1.67 km^2 with a maximum reservoir thickness of 0.3 km (850 ft). The area consists of 9.74E+7STB original oil in place (OOIP). The study area includes 19 production wells. Twelve wells have been converted to injection wells for waterflooding. Out of these 12 wells, 10 have undergone CO_2 flooding. Cranfield model consists of a 124×149×20 (X×Y×Z) Cartesian grid encompasses the entire reservoir area of 7.5×9.1 km^2 with a maximum reservoir thickness of 24.4 m. The total number of grid blocks is 369,520, out of which 82,559 grid blocks located in the north-eastern compartment of the reservoir are active (Fig. 2-b). All grid blocks have a uniform size of 61×61×1.2 m^3. This smaller zone of the reservoir includes 11 injection wells and 10 production wells.

For both fields, the Peng-Robinson equation of state (Peng and Robinson, 1976) was used to model the reservoir fluid properties. The thermodynamic model and component properties were tuned based on published literature (Dicharry et al., 1973; Weaver and Anderson, 1966). The fluid data used for this purpose included bubble point pressure, solution gas-oil-ratio, formation volume factor, oil and gas viscosities. One important factor during modelling of CO_2-EOR and storage processes in reservoirs with aquifers is to correctly generate the CO_2/brine solubility data. CO_2/water solubility in our models are modelled using Henry's Law (Henry, 1803). Henry's Law assumes a linear relationship between CO_2 partial pressure/fugacity and solubility in water.

Relative permeability curves used in Cranfield model are originally obtained from the data published by Weaver and Anderson (1966). The relative permeability endpoints and residual saturations were slightly modified to match the field production data. Although quite helpful in obtaining an acceptable match between the field data and simulation results, the slight modifications on relative permeability data have not affected the agreement between the relative permeability set used in this study and the one originally published by Weaver and Anderson (1966). For the SACROC model, oil-water relative permeability curves were available for two wells (Schepers et al., 2007). However, because of the high heterogeneity of the reservoir, the data were sparse for different core samples; therefore, Corey's functions are used for relative permeability curves. To the knowledge of the authors, there were no available data for liquid-gas relative permeabilities. Thus, Corey's function is used and end points are set during the history matching.

We also investigated the effect of relative permeability hysteresis to determine the contribution of hysteresis in CO_2 trapping. In this study, the Land (1968) equation is used to model the gas relative permeability hysteresis. In this model, the residual gas saturation S_{gr} is calculated as

$$S_{gr} = \frac{S_{gi}}{1+CS_g} \tag{1}$$

Where S_{gi} is the gas saturation at flow reversal and C is Land coefficient that is calculated as follows:

$$C = \frac{1}{S_{gr,\max}} - \frac{1}{S_{g,\max}} \tag{2}$$

where $S_{gr,\max}$ is the maximum residual gas saturation and $S_{g,\max}$ is the maximum gas saturation associated with imbibition curve. Although the residual gas saturation gets updated in every time step using Land (1968) model.

5. CO_2 storage calculation

The amount of stored CO_2 in the reservoir is calculated based on material balance (*mole*) as follows:

$$M_{CO_2}^{inj} = M_{CO_2}^{oil} + M_{CO_2}^{brine} + M_{CO_2}^{residual} + M_{CO_2}^{structural} + M_{CO_2}^{mineral} + M_{CO_2}^{produced} \tag{3}$$

where $M_{CO_2}^{inj}$ is the amount of injected CO_2, $M_{CO_2}^{oil}$ is the amount of CO_2 dissolved in oil, $M_{CO_2}^{brine}$ is the amount of CO_2 dissolved in brine, $M_{CO_2}^{residual}$ is the amount of CO_2 trapped because of relative permeability hysteresis, $M_{CO_2}^{structural}$ is the amount of CO_2 structurally trapped in the reservoir, $M_{CO_2}^{mineral}$ is the amount of CO_2 trapped due to mineral precipitation, and $M_{CO_2}^{produced}$ is the amount of produced CO_2. $M_{CO_2}^{oil}$ and $M_{CO_2}^{brine}$ can be exported directly from the simulator, but $M_{CO_2}^{residual}$ and $M_{CO_2}^{structural}$ should be calculated based on S_{gr} due to hysteresis in each grid block as follows:

$$M_{CO_2}^{structural} = \sum_{i=1}^{n} V_{m,g}(i) \times f_{CO_2}(i) \times \left(S_g(i) - S_{gr}(i)\right) \times PV(i) \tag{4}$$

$$M_{CO_2}^{residual} = \sum_{i=1}^{n} V_{m,g}(i) \times f_{CO_2}(i) \times S_{gr}(i) \times PV(i) \tag{5}$$

where $V_{m,g}$ is molar density of gas phase, f_{CO_2} is CO_2 mole fraction, S_g is gas saturation, S_{gr} is residual gas saturation, PV is net pore volume, and n is total number of grid blocks. $M_{CO_2}^{mineral}$ is negligible in the short time scale (Han, 2008; Luo and Jiang, 2012; Kempka et al., 2013).

6. History matching and scenarios

A comprehensive pressure-production history matching for primary, secondary, and tertiary recovery is conducted for both of the fields. The main purpose of history matching period was to ensure that the CO_2-EOR simulations can be started on a sound basis and with confidence. This is particularly important when initializing our CO_2-EOR model in which we know that initial oil saturation distribution is heterogeneous. Some of the major parameters we used to obtain the history match include aquifer parameters (thickness, radius, porosity and permeability), slight modifications to relative permeability parameters (end points and residual saturations) and field-wide porosity and permeability multipliers. The results show a reasonably good agreement between the field data and simulation results, which increases the reliability of the numerical model to be used for the next steps. The details of history matching of SACROC unit could be found in Hosseininoosheri et al. (2018 (a)) and the history matching of Cranfield could be found in Hosseini et al. (2018).

In this study, we consider two scenarios: 1) a water-alternating-gas (WAG) scenario, where we assumed that the operator would have done WAG injection; and 2) a continuous gas injection (CGI) scenario, where we assumed that the operator would have done continuous gas injection from the beginning of CO_2 injection. We assumed a WAG ratio of 1 (six months of CO_2 injection followed by six months of water injection. In the last scenario, the water injection rate is zero and the CO_2 injection rate is the same as the CO_2 injection rate in the WAG scenario. In order to have a fair comparison, we injected CO_2 and water in such a way as to have almost the same average reservoir pressure. Therefore, reservoir pressure is a restriction in this comparison, because if we did not have pressure restriction, then the oil production would be much higher due to the continuous tertiary EOR technique that we are applying to the field. The details of scenarios design of SACROC unit could be found in Hosseininoosheri et al. (2018 (a)) and the scenario design of Cranfield could be found in Hosseini et al. (2018).

7. Results and discussions

The results of this study show a comprehensive understanding of the CO_2 trapping mechanisms' contribution for two well-known CO_2-EOR field development strategies (e.g., WAG and CGI). Although actual operating strategy in these two fields are different (CGI in Cranfield and WAG in SACROC), our numerical modelling results show that WAG could not only balance the CO_2 storage, incremental oil recovery, and CO_2 utilization ratio but also store the trapped CO_2 with lower risk of leakage in both fields (by decreasing the amount of structurally trapped CO_2). Because of multiple alternation of CO_2 and water slugs in WAG, this approach reduces the viscous instability and therefore the efficiency of oil recovery. Our study shows that the distribution of CO_2 in different phases is different for each field. Because of the lower minimum miscibility pressure (MMP) and lighter initial oil saturation in SACROC, the partitioning of CO_2 in oil is much higher in SACROC than in Cranfield. The dissolution of CO_2 in brine is much higher in Cranfield because of the presence of strong aquifer near injection wells.

7.1. Contribution of CO_2 trapping mechanisms

Residual trapping, structural trapping, CO_2 miscibility trapping in oil, and CO_2 solubility trapping in brine were calculated and analyzed for both fields. Fig. 3 summarizes the CO_2 partitioning in different phases and forms in the observation period for Cranfield. Fig. 4 shows the CO_2 trapping mechanisms' contribution for the SACROC unit. Both of the figures are plotted in observation period (post-injection period). As can be seen in both Figs 3 and 4, WAG shows much lower mobile CO_2 (structurally trapped) and higher miscible, dissolved, and residual CO_2 in comparison with CGI. Higher mobile CO_2 in the CGI scenario introduces a higher risk of vertical displacement of CO_2 plume in the reservoir which increases the risk of CO_2 leakage in the future. Miscible CO_2 increases in WAG, because the cyclic injection of water controls the mobility ratio and stabilizes the front; therefore, the sweep efficiency of the flood increases. Higher sweep efficiency in WAG means more CO_2 in contact with oil which leads to more miscibility trapping of CO_2 in WAG scenario. In WAG scenario, cyclic injection of water makes the total amount of present water in the reservoir higher; therefore, more water is in contact with CO_2. Since the amount of CO_2-contacted brine is more in WAG, more brine solubility trapping is an expected result in WAG in comparison with CGI scenario. Residual trapping is also higher in WAG in comparison with CGI, especially during the injection period and first years of post-injection, due to the frequent relative permeability hysteresis effect during WAG injection.

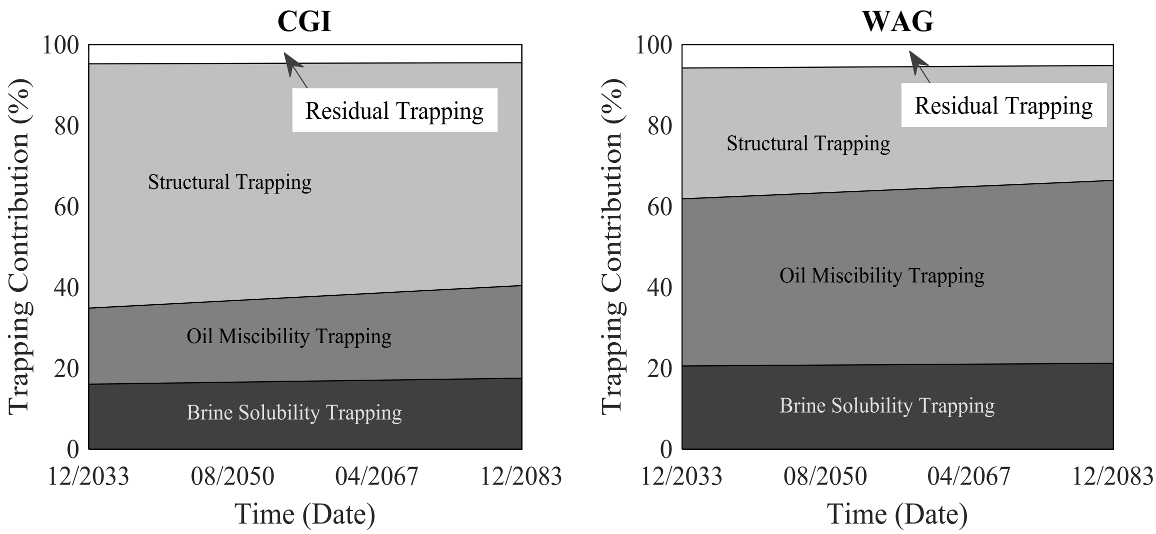


Fig. 3. Contribution of different CO_2 trapping mechanisms in post-injection period for Cranfield.

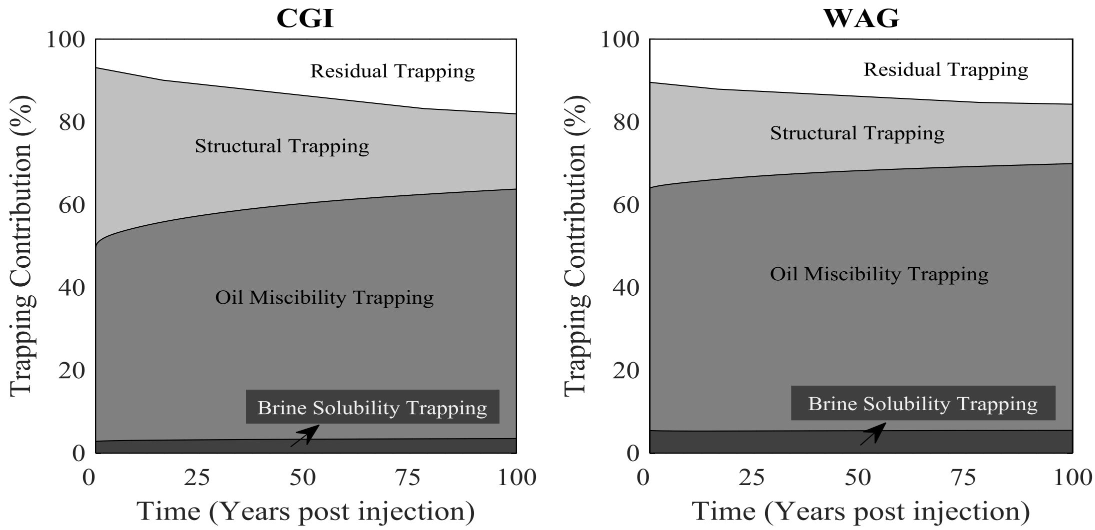


Fig. 4. Contribution of different CO_2 trapping mechanisms in post-injection period for SACROC.

7.2. Incremental oil recovery

In addition to the importance of CO_2 trapping mechanisms' contributions, the effect of each scenario on the incremental oil recovery plays an important role to decide which of these field development strategies could be more efficient, especially from the operator's point of view. Therefore, we plotted the amount of produced oil for the assumed field development strategies for both fields. Fig. 5 shows the cumulative oil production of WAG and CGI for Cranfield and SACROC.

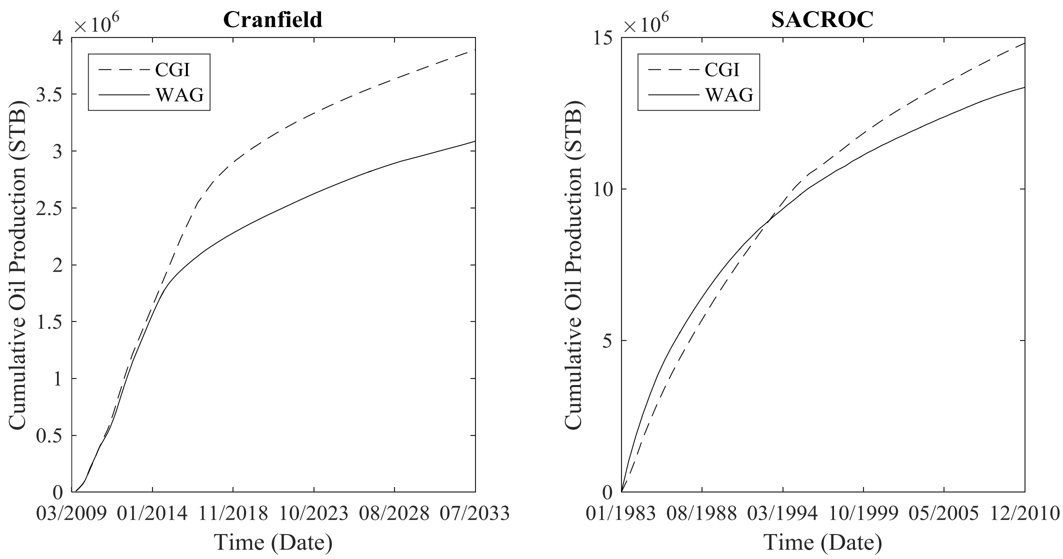


Fig. 5. Cumulative volume of produced oil for WAG and CGI.

7.3. Utilization ratios

In addition to oil production and the distribution of CO_2 in different phases, net and gross utilization ratios of CO_2 are important factors. We plotted the net and gross utilization ratios for both Cranfield and SACROC and compared WAG and CGI scenarios for both fields (Figs 6 and 7). Net and gross utilization ratios are calculated as follows:

$$\text{Gross utilization ratio} = \frac{\text{Injected CO}_2}{\text{Produced Oil}} \tag{6}$$

$$\text{Net utilization ratio} = \frac{\text{Injected CO}_2 - \text{Produced CO}_2}{\text{Produced Oil}} \tag{7}$$

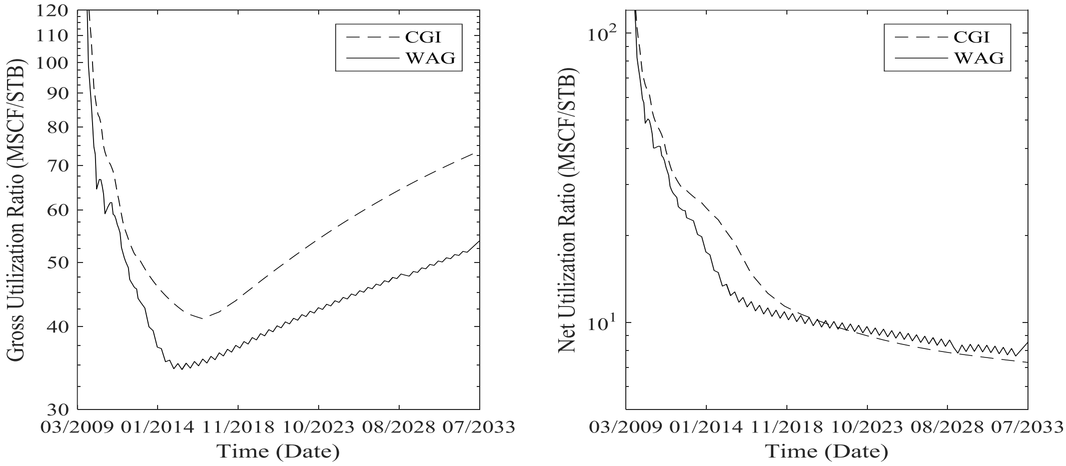


Fig. 6. Gross and net CO_2 utilization ratio for different field development strategies during CO_2 injection time (Cranfield).

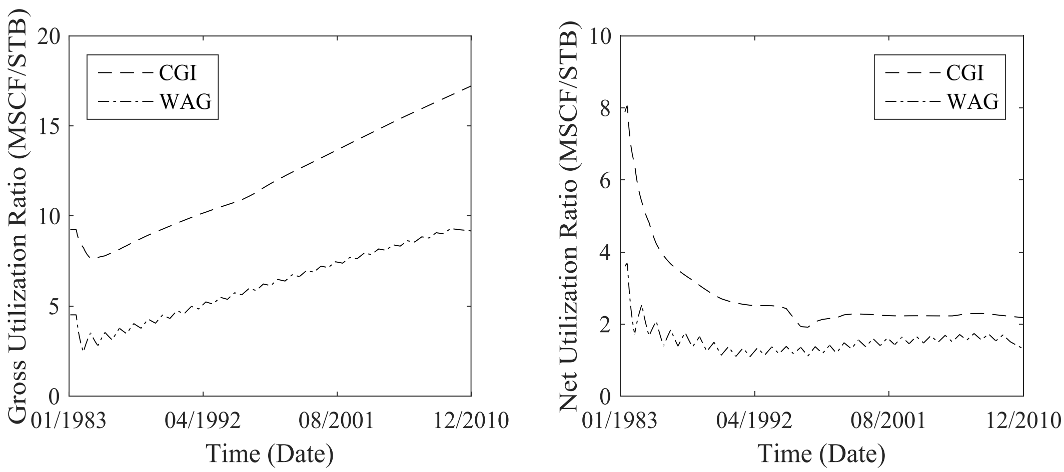


Fig. 7. Gross and net CO_2 utilization ratio for different field development strategies during CO_2 injection time (SACROC).

8. Conclusions

Although actual operating strategy in SACROC and Cranfield are different (CGI in Cranfield and WAG in SACROC), our numerical modelling results show that WAG could not only balance the CO_2 storage, incremental oil recovery, and CO_2 utilization ratio but also store the trapped CO_2 with lower risk of leakage in both fields (by decreasing the amount of structurally trapped CO_2). Because of multiple alternation of CO_2 and water slugs in WAG, this approach reduces the viscous instability and therefore the efficiency of oil recovery. Our study shows that the distribution of CO_2 in different phases is different for each field. Because of the lower minimum miscibility pressure (MMP) and lighter initial oil saturation in SACROC, the partitioning of CO_2 in oil is much higher in SACROC than in Cranfield. The dissolution of CO_2 in brine is much higher in Cranfield because of the presence of strong aquifer near injection wells. In summary, our results show that various field development strategies have a greater impact on the relative contribution of different trapping mechanisms rather than the type of the reservoir.

Acknowledgements

This work was funded by the Gulf Coast Carbon Centre at the Bureau of Economic Geology (BEG) at The University of Texas at Austin and the U.S. Department of Energy (DOE).

References

Alfi, M., Hosseini, S.A., 2016. Integration of reservoir simulation, history matching, and 4D seismic for CO_2-EOR and storage at Cranfield, Mississippi, USA. Fuel 175, 116–128.

Alfi, M., Hosseini, S.A., Alfi, M., Shakiba, M., 2015. Effectiveness of 4D Seismic Data to Monitor CO_2 Plume in Cranfield CO_2-EOR Project, in: Carbon Management Technology Conference. Carbon Management Technology Conference.

Ampomah, W., Balch, R., Cather, M., Rose-Coss, D., Dai, Z., Heath, J., Dewers, T., Mozley, P., 2016. Evaluation of CO_2 storage mechanisms in CO_2 enhanced oil recovery sites: application to Morrow sandstone reservoir. Energy & Fuels 30 (10), 8545–8555.

Choi, J.-W., Nicot, J.-P., Meckel, T.A., Hovorka, S.D., 2011. Numerical modeling of CO_2 injection into a typical US Gulf Coast anticline structure. Energy Procedia 4, 3486–3493.

Dicharry, R.M., Perryman, T.L.. Ronquille, J.D., 1973. Evaluation and design of a CO_2 miscible flood project-SACROC unit, Kelly-Snyder field. Journal of Petroleum Technology 25 (11), 1–309.

Han, W.S., 2008. Evaluation of CO2 trapping mechanisms at the SACROC northern platform: Site of 35 years of CO2 injection. New Mexico Institute of Mining and Technology, Socorro, NM.

Henry, W., 1803. III. Experiments on the quantity of gases absorbed by water, at different temperatures, and under different pressures. *Philosophical Transactions of the Royal Society of London*, *93*, pp.29-274.

Hosseini, S.A., Lashgari, H., Choi, J.W., Nicot, J.-P., Lu, J., Hovorka, S.D., 2013. Static and dynamic reservoir modeling for geological CO_2 sequestration at Cranfield, Mississippi, U.S.A. Int. J. Greenh. Gas Control 18, 449–462.

Hosseini, S.A., Alfi, M., Nicot, J.P. and Nuñez-Lopez, V., 2018, Analysis of CO2 storage mechanisms at a CO2-EOR site, Cranfield, Mississippi. Greenhouse Gases: Science and Technology.

Hosseininoosheri, P., Hosseini, S.A., Nuñez-López, V. and Lake, L.W., 2018 (a). Impact of field development strategies on CO 2 trapping mechanisms in a CO 2–EOR field: A case study in the permian basin (SACROC unit). *International Journal of Greenhouse Gas Control*, *72*, pp.92-104.

Hosseininoosheri, P., Hosseini, S.A., Nunez-Lopez, V. and Lake, L.W., 2018 (b), April. Modeling CO 2 Partitioning at a Carbonate CO 2-EOR Site: Permian Basin Field SACROC Unit. In *SPE Improved Oil Recovery Conference*. Society of Petroleum Engineers.

Hovorka, S.D., Meckel, T.A., Treviño, R.H., 2013. Monitoring a large-volume injection at Cranfield, Mississippi—Project design and recommendations. Int. J. Greenh. Gas Control 18, 345–360.

IPCC, 2014, Pachauri, R. K., and L. A. Meyer, (Eds.). Climate Change 2014: Synthesis Report. Contribution of Working Groups I, II and III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change. IPCC, Geneva, Switzerland, p151.

Kempka, T., Klein, E., De Lucia, M., Tillner, E., Kühn, M., 2013. Assessment of long-term CO_2 trapping mechanisms at the Ketzin pilot site (Germany) by coupled numerical modelling. Energy Procedia 37, 5419–5426.

Land, C.S., 1968. Calculation of imbibition relative permeability for two- and three-phase flow from rock properties. Society of Petroleum Engineers Journal 1942.

Luo, S., Xu, R., Jiang, P., 2012. Effect of reactive surface area of minerals on mineralization trapping of CO_2 in saline aquifers. Petroleum Science 9 (3), 400–407.

Peng, D.Y., Robinson, D.B., 1976. A new two-constant equation of state. Industrial & Engineering Chemistry Fundamentals 15 (1), 59–64.

Riaz, A., Tchelepi, H.A., 2006. Unstable Dynamics of Vertical Displacement in Porous Media Associated With CO_2 Sequestration. In: SPE Annual Technical Conference and Exhibition, Society of Petroleum Engineers.

Schepers, K., Gonzalez, R.J., Reeves, S.R., 2007. Optimized Reservoir History Matching Simulation of Canyon Formation, SACROC Unit, Permian Basin. Topical Report prepared for US Department of Energy, DE-FC26-04NT15514.

United States Environmental Protection Agency, 2018, Inventory of U.S. Greenhous Gas Emissions and Sinks: 1990-2016. EPA 430-R-18-003.

Weaver, L., Anderson, K., 1966. Cranfield field, Cranfield unit, Basal Tuscaloosa Reservoir, Adams and Franklin counties, Mississippi. Oil Recover. fromgas-cap Reserv. an Eng. Eval. Conserv. Pract. sixreservoirs. Interstate Oil Compact Comm. Oklahoma City 42–58.

Xu, T., Apps, J.A., Pruess, K., 2004. Numerical simulation of CO2 disposal by mineral trapping in deep aquifers. Applied Geochemistry 19 (6), 917–936.