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NUMERICAL OPTIMISATION OF CO_2 INJECTION IN A SANDSTONE RESERVOIR

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ABSTRACT

This paper presents a study on the numerical optimisation of CO_2 injection in sandstone reservoirs to maximise oil recovery. Using PETREL and CMG-GEM, the research explores various injection strategies, including Water-Alternating-Gas (WAG), miscible CO_2, and CO_2-N_2 injection. The model was created based on a publicly available research paper on an onshore oil field in the Sirt Basin, Libya. The model was validated using historical production data from January 1967 to January 2003, resulting in a Global History Matching Error of 10.37%, indicating satisfactory accuracy. For miscible CO_2 injection, the optimal maximum injection rate was 30 MMcfd. In the case of WAG, a 6-month cycle with a maximum water injection rate of 1000 bbl/d was determined to be most effective. For CO_2-N_2 injection, a mixture of 50% CO_2 and 50% N_2 at 30 MMcfd was used. In this high-pressure reservoir, CO_2 and CO_2-N_2 injections yielded higher recovery rates than WAG despite the lower mobility of gases. The high reservoir pressure of 4000 psia and low-pressure differentials during injection made gas injection particularly effective due to compressibility. The findings underscore the significance of customising injection strategies to reservoir conditions to maximise oil production.

Keywords: *CO2-N2 injection, CMG-GEM, EOR, fluid displacement, high-pressure reservoirs, injection strategies, minimum miscibility pressure, PETREL, reservoir simulation, water-alternating-gas*

INTRODUCTION

Reservoir fluid production in the oil and gas industry is a complex process that occurs in three distinct phases, each critical to maximising initial oil recovery (OOIP). Primary recovery, also known as the first phase, relies on the reservoir's natural processes to drive fluid production. This recovery method is based on phenomena such as aquifer drive, gas cap drive, gravity drainage, gas solution, and expansion of rocks and fluids [1]. In some cases, artificial pumps are used to improve the extraction process during this period. However, despite these efforts, utilisation of primary recovery typically produces only between 5% to 15% of the original oil in place [2]. As the reservoir depletes and the natural pressure declines, the secondary recovery stage is initiated to introduce an external energy source, thereby maintaining the formation pressure and improving hydrocarbon production. This stage involves techniques such as gas or water flooding to elevate the reservoir pressure to its initial condition, which can significantly enhance oil recovery. Waterflooding during this stage can increase the recovery factor. Recovery values range between 35% and 50% of OOIP [3].

Following the conventional stages, the industry moves towards the enhanced oil recovery (EOR) phase, employing various innovative techniques to extract additional residual hydrocarbons. EOR strategies, including thermal, chemical, or miscible flooding, aim to mobilise trapped fluids by altering their properties, with potential recovery improvements of up to 75% of OOIP [4]. The first commercial application of CO_2 injection for EOR in 1972 at the SACROC Unit of the Kelly-Snyder Field in Texas underscored the effectiveness of this approach, marking a turning point in the use of CO_2 for revitalising mature oil fields and significantly increasing oil production [5].

The adoption of advanced EOR methods, particularly CO_2 injection, has become a priority for the oil and gas industry to enhance the profitability of ageing fields and navigate the challenges of newly discovered reservoirs. These methods address the limitations of conventional recovery techniques, which typically capture only 10% to 40% of OOIP. CO_2 injection in miscible or immiscible phases reduces oil viscosity and improves its flow toward production wells, contributing to increased oil recovery. Also, techniques such as CO_2 miscible/immiscible injection and water alternating gas (WAG) injection have been developed to optimise oil recovery, offering 5 to 10% incremental recovery factors over conventional methods. These advancements boost oil extraction efficiency and facilitate CO_2 storage and sequestration, highlighting the industry's efforts to improve recovery rates while addressing environmental concerns. This study aims to optimise CO_2 injection strategies in a sandstone reservoir to maximise oil recovery and enhance CO_2 sequestration. By comparing different CO_2 injection methods—including WAG, miscible CO_2, and CO_2-N_2 injection—this research seeks to determine optimal parameters for each strategy within the specific reservoir characteristics of the Sirt Basin, Libya. The study also investigates the impact of high reservoir pressures on injection efficacy, emphasising the need for tailored EOR techniques that consider economic and environmental sustainability.

LITERATURE REVIEW

Numerical Simulation and Optimisation of CO_2 Injection

One viable approach to achieve this is the utilisation of CO_2 for EOR by injecting it into oil reservoirs. This method has widespread commercial application, mainly due to CO_2's cost-effectiveness, high displacement efficiency, and potential environmental benefits when disposed of in petroleum reservoirs [6]. Numerical simulation tools, like the CMG software suite, play a pivotal role in the planning and optimising of CO_2 EOR projects. These tools allow for detailed modelling of reservoir dynamics, CO_2 fluid behaviour, and interaction between CO_2 and reservoir oil under various injection scenarios [6]-[7]. Simulations can help optimise injection rates, pressure, and strategies to maximise oil recovery while minimising costs and environmental impact.

According to Fath and Pouranfard [6], at optimum identified injection rates for immiscible and miscible CO_2 injection scenarios, oil recovery more than doubled compared to the natural depletion scenario. Moreover, the oil recovery percentage improved by approximately 3% when switching from immiscible to miscible CO_2 injection, further indicating that miscible CO_2 injection not only significantly enhances oil recovery but also maintains higher average field pressures. Hence, miscible CO_2 injection provides a higher recovery percentage than immiscible CO_2 injection.

Another study conducted an experiment that noted that CO_2 injection in an aquifer leads to higher ultimate recovery for all of the tested rates of injection in comparison with CO_2 injection into the pay zone [8]. Additionally, when CO_2 is injected simultaneously into the aquifer and pay zone, it leads to the highest oil recovery factor. The study compared three injection plans: natural, soluble CO_2, and insoluble CO_2. Soluble CO_2 injection outperformed, increasing aquifer influx, with the lowest average water saturation observed when injected into the aquifer. The critical rate of 7 MMSCFD showed the highest oil production. The immiscible injection was dominant over the miscible injection after 45% recovery—simultaneous injection maximised recovery, surpassing other methods.

Minimum Miscibility Pressure (MMP) in CO_2 EOR

The MMP concept plays a vital role in the effectiveness of CO_2 EOR techniques. MMP refers to the minimum pressure required for CO_2 to mix with the reservoir oil without creating any interface, allowing more efficient displacement of oil [7]. Accurately determining MMP is crucial for creating an optimal CO_2 injection strategy, which will help ensure maximum oil recovery. It essentially describes the compatibility between crude oil and CO_2. Accurate estimation of MMP is essential for accurately implementing CO_2 miscible displacement processes. Different correlations have been proposed for predicting MMP in CO_2 EOR. One suggested by Alston establishes MMP as a function that depends on reservoir temperature, the molecular weight of C5+ components, and the proportion of volatile components to intermediate components. The equation is calculated as:

If $P_b \geq 0.345\ MPa$

$$MMP = 6.056\ \times 10^{-6} \times (1.8 \times T_R + 32)^{1.06} \times (MW_{C_{5+}})^{1.78} \times (\frac{Vol}{Int})^{0.136}$$

$$\tag{1}$$

If $P_b < 0.345\ MPa$

$$MMP = 6.056\ \times 10^{-6} \times (1.8 \times T_R + 32)^{1.06} \times (MW_{C_{5+}})^{1.78}$$

Firoozabadi proposed a different approach to MMP estimation where it is a function depending on reservoir temperature, the molecular weight of C7+ components, and the mole percent of intermediate components in oil. The equation is defined as:

$$MMP = 9{,}433 - 188 \times 10^3 \times \left(\frac{x_{int}}{M_{C_{7+}} \times T^{0.25}}\right) + 1430 \times 10^3 \times \left(\frac{x_{int}}{M_{C_{7+}} \times T^{0.25}}\right)^2 \tag{2}$$

Water Alternating Gas (WAG) Injection in EOR

WAG injection is an advanced EOR technique that alternates between injecting water and gas (commonly CO_2) into the reservoir to improve oil recovery efficiency beyond what can be achieved by waterflooding or gas injection alone due to poor sweep efficiency [8]. The WAG method includes the benefits of displacing fluids to enhance oil mobilisation and recovery.

WAG injection improves oil displacement and recovery through several mechanisms: 1) as gas is injected, oil viscosity is reduced and oil mobility increases, while water injection maintains reservoir pressure and improves sweep efficiency. The cyclical nature of the WAG method helps manage gas mobility, minimise issues such as gas channelling, and enhance overall sweep efficiency within the reservoir. Numerical simulation tools, notably the CMG suite, are crucial for designing and optimising WAG injection strategies. These tools enable detailed multiphase flow modelling within reservoirs, optimising injection parameters such as WAG ratio, cycle length, and injection rates to maximise oil recovery. Despite its potential, WAG injection faces challenges, including optimising the WAG ratio and cycle timing, managing reservoir heterogeneities, and controlling the costs associated with gas procurement and injection operations. Ongoing research focuses on improving the understanding and modelling of WAG processes to overcome these challenges. WAG injection presents a viable method for enhancing oil recovery in sandstone reservoirs, particularly when combined with CO_2 as the gas phase [11].

Identified as prime targets for CO_2 storage owing to their extensive capacity, saline aquifers have garnered significant attention [12]. The study delineates the main CO_2 trapping mechanisms, emphasising structural, residual, and solubility trapping as efficient means for CO_2 sequestration within these aquifers. Particularly noteworthy is the finding that WAG injection proves significantly more effective in CO_2 trapping compared to continuous CO_2 injection strategies, underscoring its potential for enhancing storage efficiency and mitigating environmental impact.

Another study by Pancholi et al. [11] explores the optimisation of WAG (CO_2) flooding for EOR in Himmatnagar sandstone reservoirs, focusing on the effects of various WAG injection ratios. Through experimental work and simulation studies, the researchers aimed to improve oil recovery beyond what is achievable with water flooding alone. They conducted detailed analyses of rock and fluid properties, including X-ray diffraction and ASTM procedures for determining the composition of the crude oil. The study found that a WAG ratio of 2:1 yielded the highest additional oil recovery, about 34% of the original oil in place, suggesting that increasing the WAG ratio leads to higher oil recovery.

CO_2-N_2 Injection in EOR

Nitrogen (N_2) injection, though less effective than carbon dioxide (CO_2) in oil recovery, presents advantages in particular situations. Due to its lower solubility in oil and higher interfacial tension, N_2 can effectively displace oil from smaller pores, resulting in a larger gas-swept area. However, this comes with higher resistance in larger pore channels. Consequently, N_2 flooding can enhance the overall sweep efficiency in heterogeneous reservoirs [13].

The combination of CO_2 and N_2 injection, known as alternating CO_2-N_2 injection (NAC), uses the strengths of both gases. NAC has been shown to increase CO_2 injection capacity and improve oil recovery temporarily. Numerical simulations and core flooding experiments further support the efficiency of NAC in enhancing oil recovery and maintaining reservoir pressure, particularly in heterogeneous reservoirs [13]. NAC has been studied for its potential to improve gas distribution, gas-swept areas, cumulative oil production, and CO_2 storage. Studies have shown that alternating slugs of CO_2 and N_2 can optimise gas mobility and front movement, enhancing overall recovery and storage efficiency. Optimising the NAC process involves balancing the proportions of CO_2 and N_2 to maximise CO_2 storage and oil recovery [13].

A study by Robinson et al. [14] also focused on evaluating different CO_2 EOR methods and comparing different injection ratios for CO_2 and N_2. The results showed that when the percentage of injected CO_2 was increased, the recovery factor also increased. Among the various cases, the optimal scenario was found to be a Case with 50% CO_2 and 50% N_2 injection composition, which had the highest utilisation rate, the highest recovery factor, and the most CO_2 stored in the reservoir.

METHODOLOGY

Based on Figure 1, the initial step involves identifying the important reservoir parameters, which are crucial for the accuracy and relevancy of the model. Once these parameters are set, the process follows: building a fluid model in CMG-WINPROP and a 3D reservoir model in PETREL. Following the construction of the 3D model in PETREL, it is populated with reservoir properties. Subsequently, the RESCUE tool converts this PETREL model into a format compatible with CMG-Builder. With the fluid model and conversion in place, the following action is to input all the data into CMG-Builder, create well models, and apply constraints. The next crucial stage is history matching, where the

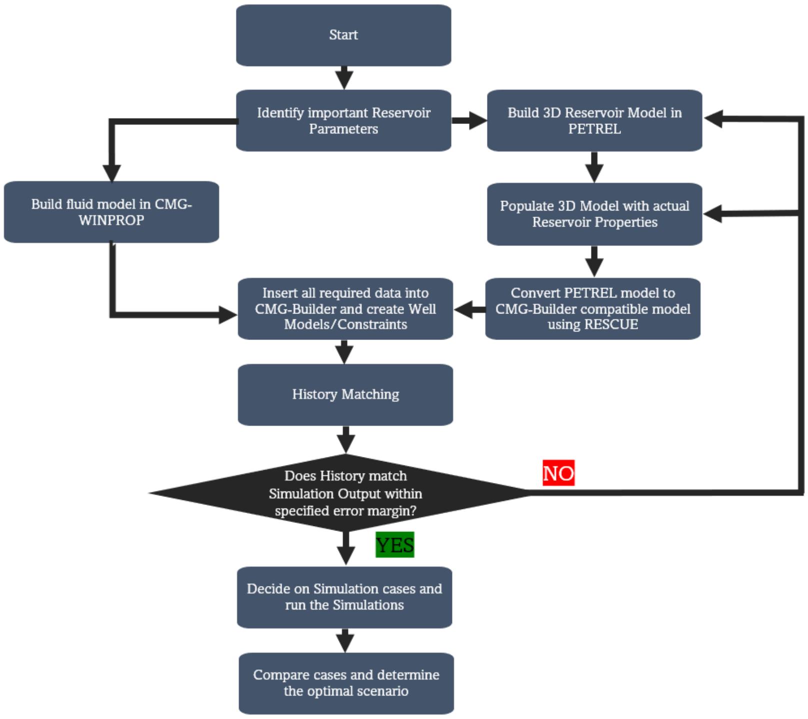

Figure 1 Methodology flowchart

simulation output is compared against historical data within a predetermined error margin. If the match is successful, the process proceeds to the selection of simulation cases and the execution of simulations, after which the outcomes are compared to select the optimal scenario. However, if the history does not align with the simulation output, the methodology necessitates a return to the adjustments of the 3D reservoir model and a reevaluation of the populated properties, ensuring an adjusted and more accurate model before proceeding.

The study focuses on an onshore oil field in the Sirt Basin, Libya. The developed reservoir model consists of 9,600 blocks, simulating an inverted 5-spot injection configuration. The geometry of the reservoir is defined using a corner point grid, which includes 40 × 40 × 6 grid blocks in the *i*, *j*, and *k* directions, respectively. The reservoir is characterised as medium sand with medium porosity and high permeability. The horizontal permeability in the *i* and *j* directions is equal, while the vertical-to-horizontal permeability ratio is 0.1. The area of the reservoir model is 5750 ft × 5750 ft, with a thickness varying between 25 ft and 100 ft.

As shown in Figure 2, the reservoir consists of 11 oil-phase components, with no gas phase as no gas cap is present. Four vertical producer wells are positioned at each corner edge, while a vertical injector well is located at the model's centre to simulate an inverted five-spot injection pattern. The production is carried out from all four production wells, with only layers 1, 2, 3, 4, and 5 perforated. The study assumes the reservoir is in an isothermal condition.

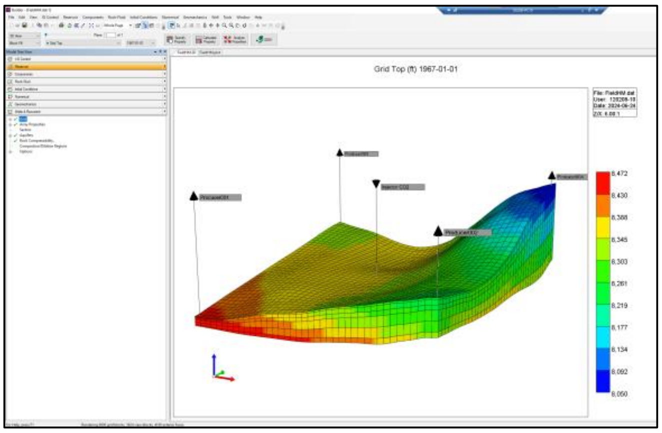

Figure 2 Reservoir model in CMG-Builder

RESULTS AND DISCUSSION

Model Validation

History matching was conducted using available historical production data from January 1967 to January 2003 to validate the model (Figure 3). Wells were produced naturally with aquifer support and without any injection. Due to the unavailability of detailed production data for water and oil per well, and with only total field production data available, the assumption was that each well produced the same amount over the production. Thus, production history was divided equally between the four producer wells. After simulating the historical production, the oil rates in the model were matched to the historical data. Due to the uncertainty of aquifer thickness, the value was adjusted to minimise history matching error. Considering the assumptions made during model setup and the unavailability of production data per well, the lowest Global History Matching Error was calculated to be 10.37%, which indicates a close match between historical data and simulation behaviour. Afterwards, different injection cases were tested throughout the next period, from January 2003 to January 2031.

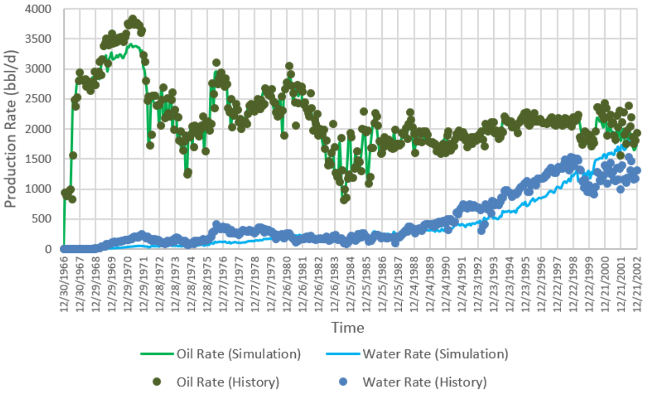

Figure 3 Validation of field oil and water production rates

Simulation and Optimisation of Case 1 – Miscible CO_2 Injection

The correct injection gas was first specified to simulate the injection of CO_2 through the injection well located at the centre of the reservoir. The decision to use miscible CO_2 was based on the reservoir pressure and the MMP obtained from WINPROP modelling using the "Multiple Contact Miscibility" method. The MMP was determined to be 2375 psia, while the reservoir pressure decreased to an average value of 4000 psia. This high reservoir pressure makes it impossible to inject immiscible CO_2, as miscible CO_2 injection is more effective under these conditions. The literature review indicated that miscible CO_2 injection typically results in much higher recovery rates compared to immiscible injection [6]. Given this, we proceeded with the simulation of miscible CO_2 injection over a range of injection rates.

CO_2 injection was constrained by maximum injection rate and maximum bottom hole pressure. Maximum bottom hole pressure (BHP) was set to 4200 psia for all injection cases to ensure no potential risk of fracturing. The main parameter to be changed for sensitivity analysis in all of the simulations was the maximum injection rate.

Figures 4, 5 and 6 show the optimisation was based on plotting the field's cumulative oil production and CO_2 storage efficiency against the maximum CO_2 injection rate. This analysis observed that cumulative recovery did not increase beyond the maximum injection rate of 30 MMcfd. Therefore, 30 MMcfd was chosen as the optimised maximum injection rate for CO_2, as it provided the highest recovery without unnecessary excess injection.

Simulation and Optimisation of Case 2 – WAG

Following the optimisation of CO_2 injection, the following simulation case is the WAG simulation using the previously determined optimised CO_2 maximum injection rate of 30 MMcfd. A sensitivity analysis was conducted on the WAG injection cycles to optimise the WAG process further as shown in Table 1. Three-, four- and six-month injection cycles were tested to determine the most effective period for alternating between water and gas injections. Optimally, 6 month WAG cycle was selected as the base case due to the highest cumulative oil recovery.

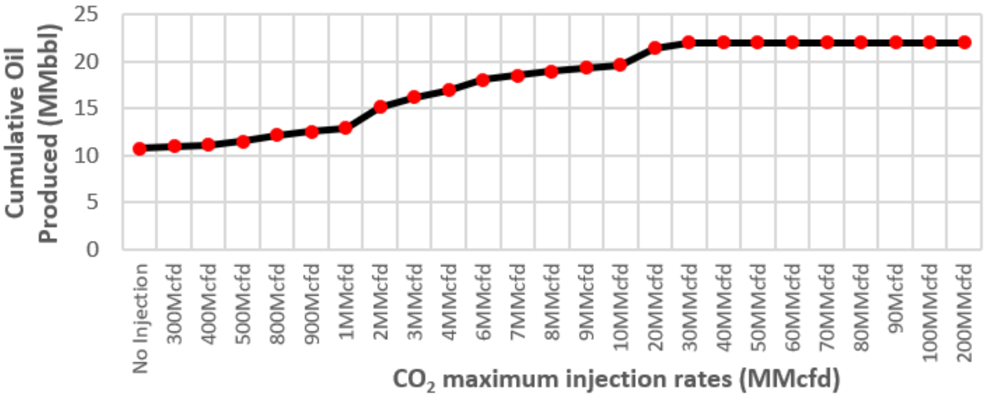

Figure 4 CO_2 maximum injection rate versus cumulative oil recovered

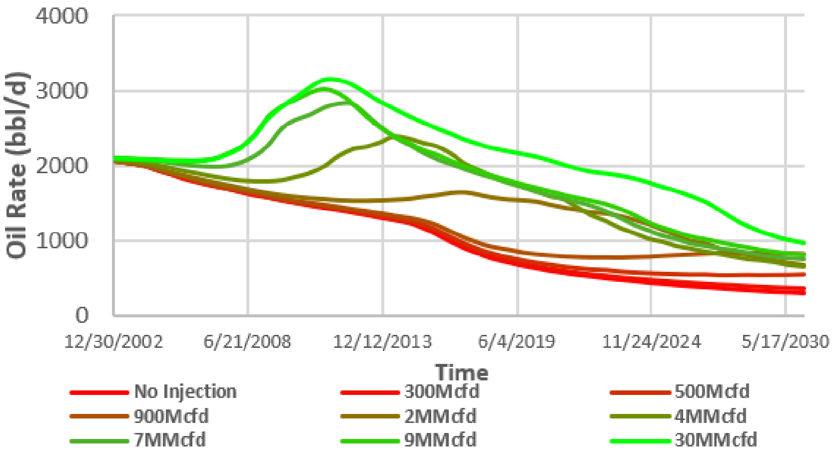

Figure 5 Oil production rate vs time-based on different CO_2 injection rates

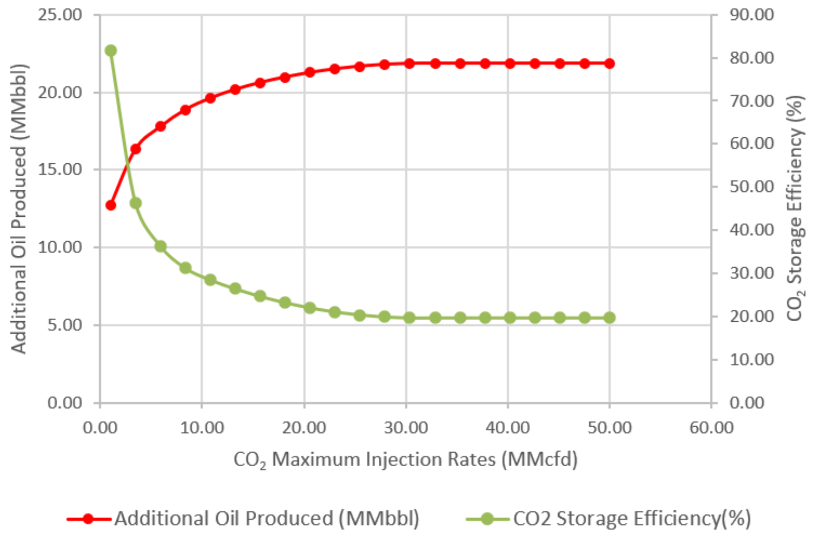

Figure 6 CO_2 injection rates vs additional oil recovery and CO_2 storage efficiency

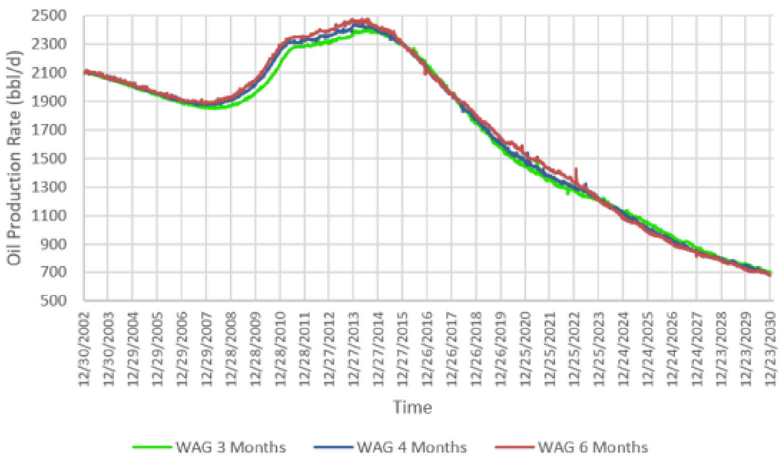

Figure 7 Oil production rate versus time for different WAG cycles

Table 1 WAG cycle optimisation summary

WAG SUMMARY	Cycle Duration (month)	CO_2 stored (ft^3)	CO_2 stored effieciency (%)	Cumulative oil production (MMbbl)
CO_2/H_2O	3	1.69E+10	41.34	17.19
	4	1.75E+10	41.30	17.32
	6	1.71E+10	39.75	17.47

After identifying the optimal WAG cycle based on Figure 7, the next step was to optimise the maximum water injection rate. This was achieved by analysing the maximum water injection rate plot versus cumulative oil recovery. By varying the maximum water injection rate as shown in Figure 8, the rate that maximised oil recovery was identified at 1000 bbl/d and selected as the optimal maximum water injection rate. Thus, optimised cycle durations and CO_2 and Water injection rates were obtained.

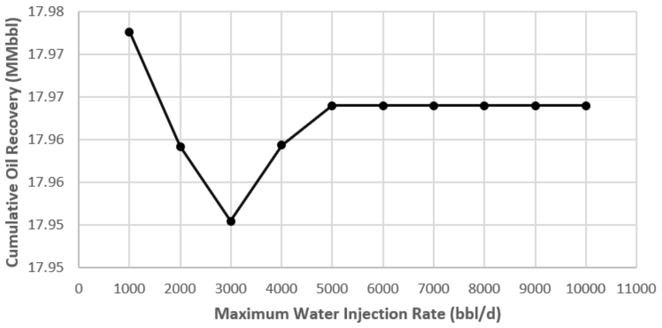

Figure 8 WAG – Maximum water injection rate versus cumulative oil recovery using fixed maximum CO_2 injection rate

Simulation and Optimisation of Case 3 – Simultaneous CO_2 and N_2 Injection

Following the optimisation of WAG injection, the next is to explore the potential impact of different fluid mixtures on production. Thus, a simulation using an equal proportion of CO_2 and N_2 injection was conducted to test the sensitivity to the injected fluid. This approach was motivated by the different advantages offered by each gas. CO_2 is known for its ability to reduce oil viscosity and enhance oil recovery through miscibility, while N_2 can help maintain reservoir pressure and improve sweep efficiency due to its high mobility and lower cost. The simulation was set up using the optimised maximum injection rate of 30 MMcfd, with a mixture comprising 50% CO_2 and 50% N_2.

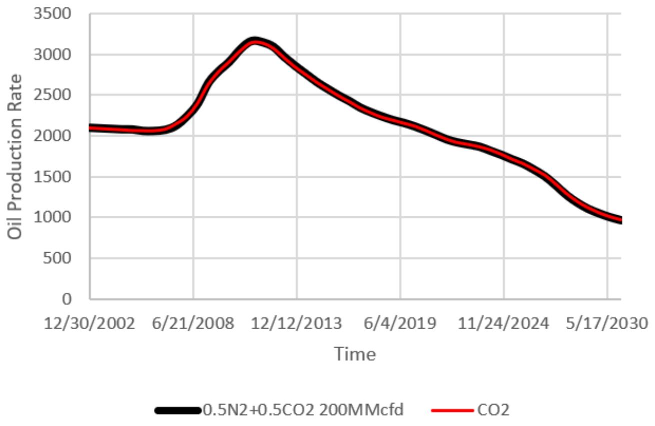

Figure 9 CO_2/N_2 injection

Based on Figure 9, the results indicate that the production rates remained nearly consistent throughout the forecasting period compared to pure CO_2 injection. This stability can be attributed to the similar mobilities of CO_2 and N_2, which help maintain a balanced injection profile and efficient reservoir sweep. Studies have demonstrated that mixing CO_2 with N_2 can optimise gas injection processes by combining the strengths of both gases, thus improving oil recovery while potentially lowering operational costs and mitigating the risk of CO_2 channelling and gravity override[13]-[14].

Results Comparison and Discussion

CO_2 Injection

Based on results show in Table 2, the optimised maximum CO_2 injection rate of 30 MMcfd resulted in high recovery rates, demonstrating the effectiveness of miscible CO_2 injection in enhancing oil production. The high reservoir pressure (approximately 4000 psia) ensured the CO_2 remained miscible, facilitating efficient oil displacement and reducing oil viscosity. The high mobility of CO_2 contributed to rapid oil displacement, resulting in increased production rates.

Table 2 Recovery factor summary

Simulation Dates	Simulation Case	Recovery Factor of each Stage (% of STOIIP)	Total RF (%)
1.1.1967 – 1.1.2003	Primary Production	49.18%	-
1.1.2003 – 1.1.2031	Continuation of Primary Production (No injection)	18.67%	67.85%
1.1.2003 – 1.1.2031	CO_2 injection with optimised parameters	38.47%	87.65%
1.1.2003 – 1.1.2031	CO_2/N_2 injection with optimised parameters	38.41%	87.59%
1.1.2003 – 1.1.2031	WAG injection with optimised parameters	31.37%	80.55%

CO_2/N_2 Injection

The simulation with an equal proportion of CO_2 and N_2 (50% CO_2 and 50% N_2) showed comparable results to the pure CO_2 injection. The combined injection leveraged the high mobility of both gases, which facilitated efficient oil displacement and maintained reservoir pressure. This mixture also demonstrated the potential for cost reduction and operational flexibility. The similar mobilities of CO_2 and N_2 ensured that the injection profile remained balanced, and the recovery rates were maintained throughout the forecasting period.

WAG Injection

Although designed to improve sweep efficiency through cyclic injection of CO_2 and Water, the WAG method resulted in lower recovery rates than the pure gas injections. The primary reason for this is the lower mobility of water compared to CO_2 and N_2 gases. While the cyclic nature of WAG injection ensures a more thorough sweep of the reservoir, the slower water spread towards the producing wells reduces the overall production rate. Additionally, a significant

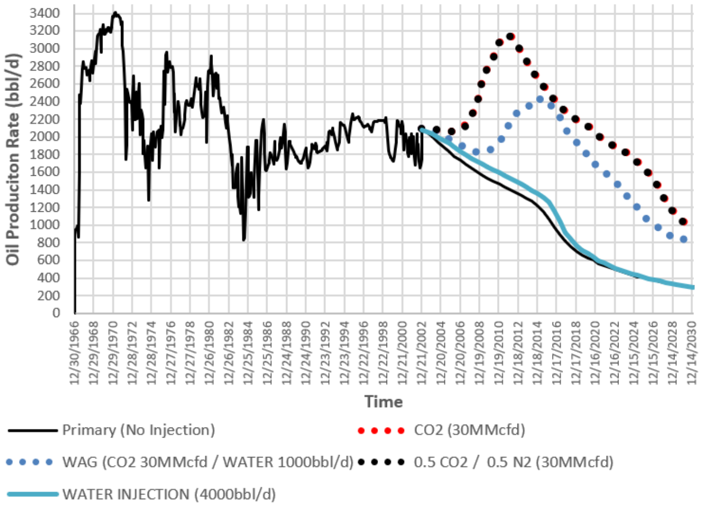

Figure 10 Comparison of different optimised injection simulation cases

constraint with WAG is the maximum BHP. Since water is incompressible compared to CO_2 and N_2 gases, injecting water at a higher rate becomes difficult without risking reaching fracture pressure. This process limits the efficiency of the WAG process despite its potential for improved sweep efficiency. Additional confirmation for this comes from simulating water injection. Maximum Water injection rate was optimised at 4000 bbl/d. Similar results are achieved due to the incompressibility of water and a maximum production limit set on production wells, which prevents water from being injected at the intended maximum rate.

Comparative Analysis

As per comparison of results in Figure 10, it is clear that CO_2 and CO_2/N_2 injections outperform the WAG method regarding recovery rates for this specific reservoir. The main reasons for such an effect include higher mobility of the injected gases, which displace oil more rapidly on the upper layers of the reservoir, even if the sweep efficiency is much lower compared to WAG. Due to material balance and low-pressure differential of 200 psi for water injection, water could only replace the amount of oil produced, which resulted in an even but slower sweep within the same given simulation time.

CONCLUSION

This research has shown the significant potential of numerical optimisation for enhancing CO_2 injection in sandstone reservoirs. The study demonstrates substantial increases in oil recovery efficiency by integrating different methods, like Water-Alternating-Gas (WAG), miscible CO_2, and CO_2-N_2 injection. The research uses tools like PETREL and CMG-GEM to provide insights into the interactions between CO_2, reservoir fluids, and rock structures, emphasising optimal injection strategies to maximise oil recovery. It is recommended that field trials be done to validate the simulation results and ensure applicability in an actual field case. Future research should include detailed economic and environmental analyses focusing on CO_2 sequestration and emission mitigation. Integrating AI and machine learning can further enhance simulation accuracy. Collaboration between academia, industry, and government agencies is crucial for knowledge sharing and accelerating the adoption of optimised enhanced oil recovery (EOR) techniques. Continuous monitoring systems should be implemented to allow dynamic adjustments based on reservoir conditions. By following these recommendations, the oil and gas industry can enhance the economic and environmental sustainability of CO_2 EOR techniques, contributing to global efforts to reduce carbon emissions.

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