Journal of Petroleum Science and Technology 12(2): 34, 2022, Pages 2-16
DOI:10.22078/JPST.2022.4775.1795

Journal of Petroleum Science and Technology

Research Paper

https://jpst.ripi.ir/

Performance Analysis of Enhanced Gas Recovery Approach

Ashiqul Islam Shuvo*, Zayed Bin Sultan and Sagar Hussain Sabuz
Department of Petroleum and Mining Engineering, Chittagong University of Engineering and Technology, Chattogram, Bangladesh

Abstract
Production of massive gas fields in Bangladesh is nearing to be ended in the near future.As global energy demands rise due to the rising population and rapid urbanization, maximizing available resources use has become essential. Therefore, preparing the field's measurement to extend the field's lifetime needs to get attention. One such measure is enhanced gas recovery (EGR); it is a potential technique to maximize the efficiency of the recovery process, which utilizes fracturing, water flooding, and gas injections to increase gas production. In this study, a simulation of the performance of three EGR techniques with linear, triangular, and corner injection well placements is presented; and thereby, the simulation results of the techniques are analyzed. Simulation of water flooding, CO_2 injection, and WAG (water alternating CO_2 gas) techniques are performed to evaluate the performance of the reservoir under these injections. A suggestion has been provided in favor of the suitable approach among them. The performances are evaluated based on two factors: the amount of additional gas which has been recovered and the quality of the produced gas. After analyzing the results for each case scenario, it is concluded that CO_2 injection can be applied to increase natural gas recovery up to 24.55% more than the base case model. In comparison, the water flooding and WAG models contributed 16.57% and 8% more gas recovery, respectively. The EGR techniques are simulated using the GASWAT feature in the fully implicit formulation of the E300 compositional simulator, a tool of the ECLIPSE suite. Finally, by analyzing the performances of three EGR techniques, this simulation study suggests the CO_2 injection model as the most suitable EGR technique over the water flooding and WAG models in terms of more gas recovery.

Keywords: Enhanced Gas Recovery, CO_2 Flooding, Waterflooding, WAG, Injection Well Placement.

Introduction
The high demand for energy worldwide, commensurate with the rising population and rapid urbanization, makes it critical to maximize the use of available resources. Therefore, the exploitation of the available energy resources has gained more attention in the present days to satisfy the growing energy needs worldwide [1]. Many methods have been investigated to increase recovery from depleted gas reservoirs. Enhanced Gas Recovery (EGR) utilizes various techniques to achieve increased gas production from the reservoir. Following approaches such as fracturing, waterflooding, and gas injections are used. CO_2 emission from fossil fuels is expected to pose serious environmental consequences and the amount of CO_2 in the atmosphere is already far too large to ignore [2]. Global attention has emerged from the combustion of fossil fuels to reduce carbon dioxide (CO_2) emissions. Petroleum companies are interested in employing CO_2 to enhance oil and gas recovery (EOR and EGR) to deal with the rapid growth in global energy requirements [3]. Combining these two concepts can potentially improve hydrocarbon recovery and sequestration through the injection of CO_2. The energy sector has noticed numerous depleted oil and gas reservoirs from which secondary and tertiary oil and gas can be recovered by injecting CO_2 instead of water into the reservoirs. This technique allows for the extraction of additional fuel, and it permits for the sequestration of CO_2, which in turn, it is expected to provide a significant environmental advantage [4-6]. Significant effort has been devoted to enhancing gas recovery using CO_2 [7, 8]. The method of injecting CO_2 into natural gas reservoirs is still in its infancy due to the excessive mixing of injected fluid and displacing fluid [9-21]. It remains a costly process from a financial standpoint and a precarious process in terms of the outcome and contamination of the field [22]. Furthermore, it is concerned that CO_2 would mix with the initial gas in place and degrade the gas production [23]. In addition, in gas–gas mixing, the injected CO_2 make its way to the production well, a process known as

**Corresponding author:* Ashiqul Islam Shuvo, Department of Petroleum and Mining Engineering, Chittagong University of Engineering and Technology, Chattogram, Bangladesh
E-mail addresses: ashiqulshuvo@cuet.ac.bd
Received 2022-04-06, Received in revised form 2022-10-23, Accepted 2022-11-08, Available online 2023-02-25

the CO_2 breakthrough. At this point, natural gas production began to fall noticeably, while CO_2 production increased significantly [24]. Though CO_2 has some drawbacks, it has some positive properties, making CO_2-EGR attractive. At all relevant reservoir conditions, CO_2 had a 2 to 6 times density more methane, and it had a lower mobility ratio; hence, it is classified as a high-viscosity component. Another appealing physical property of CO_2 was its solubility. At reservoir conditions, carbon dioxide may have been more soluble than methane. It could postpone the occurrence of CO_2 breakthroughs [25]. Because of the favorability of these two CO_2 properties, CO_2 would migrate downwards, which would relatively stabilize the displacement process between the injected CO_2 and the methane that was initially present [26]. As a result, the injection wells were proposed to be placed or located at the bottom layers of the reservoir. Furthermore, the production wells are located in the upper layers of the reservoir to allow for a gravity effect for CO_2 injection [24]. Some studies have shown that injecting CO_2 at the reservoir's bottom can boost natural gas production due to its high density and function as a "cushion gas" and that CO_2-EGR is economically viable [25, 10, 27]. Many simulation studies on CO_2-EGR have been conducted since the original concept of CO2-EGR was proposed by Burgt et al. [8]. Interestingly, the results of the studies were much more satisfactory. Furthermore, CO_2-enhanced gas recovery (CO_2-EGR) with simultaneous CO_2 underground sequestration can create additional natural gas from depleted gas reserves [28, 29]. The "Tempest" simulation software was used by some authors [19] to generate a three-dimensional reservoir model in their studies. The primary goal of this research was to demonstrate the possibility of improved natural gas recovery and CO_2 storage by re-injecting CO_2 produced by the natural gas reservoir. After examining the data for each case scenario, it was determined that CO_2 injection might boost natural gas recovery while sequestrate a significant percentage of the injected CO_2 for this specific gas reservoir. Injection well characteristics and placements in the reservoir and CO_2 injection rate must be optimized to achieve the greatest performance for natural gas production and CO_2 storage [30]. The performance of displacing CH_4 with CO_2 is influenced by reservoir pressure and temperature, injection rate, and the characteristics of the rock and fluids [31]. Several authors have conducted extensive studies to improve the CO_2-EGR process using various connate water concentrations [9] and CO_2/N_2 gas mixtures in different mole ratios [32]. Alternating N_2 gas injection as a potential technique for enhanced gas recovery and CO_2 storage in consolidated rocks was also investigated [33]. Different methods of EGR rather than using CO_2 were studied by some authors. The simultaneous production of gas and water, known as co-production, is used to control water influx into water-drive gas reservoirs. The co-production technique can increase gas recovery by up to 20% [34]. A propellant-based technology that allows control of borehole pressurization to obtain multiple radial fractures around the wellbore has been developed to enhance gas recovery [35].

Water flooding is a form of gas recovery wherein the energy required for moving the gas from the reservoir rock into a producing well is supplied from the surface using water injection and the induced pressure from additional water. Water is injected into some wells to keep reservoir pressure high, while gas is produced in others. The goal is to position the injection and production wells so that the gas "sweeps" toward the producing wells.

Pressure maintenance and water flooding are more challenging to distinguish in a gas reservoir, but both can still be used to increase gas recovery.

When a water injection project is designed, both the pressure and volumetric sweep efficiency must be considered [36]. Moreover, it is demonstrated that flooding with water can improve gas recovery in a low-pressure gas reservoir. Water injection at the abandonment pressure displaces a percentage of the gas generated via the production well, leaving less residual gas saturation. Water flooding is attractive for gas recovery mechanisms due to the following factors: 1. Water is cheap. 2. Water is often readily available from local streams, rivers, seas, or wells sunk into shallower or deeper subterranean aquifers. 3. Because of the increased reservoir pressure, water injection successfully makes the nearby producing wells flow or be pumped at higher rates.

The Water Alternating Gas (WAG) process is a cyclical process that involves injecting alternating water and gas. WAG injection's primary goal is to improve macroscopic and microscopic sweep efficiency by maintaining nearly initial high pressure, slowing injected gas breakthrough. The WAG model also provides mobility control, which extends the life of the gas project and improves gas recovery. Carbon dioxide gas is commonly used for miscible displacement because it has lower pressure and improves sweep efficiency. The primary goal of miscible gas slugs is to boost the microscopic sweep efficiency and touch attic hydrocarbon in locations not addressed by water injection; gravity segregation is typical in high permeability sandstone reservoirs. Because gas tends to migrate to the reservoir's top, and dense water tends to migrate to the reservoir's bottom, attic hydrocarbons in the reservoir's upper parts may be contacted by the injected gas. In contrast, the water flood acts as a piston to push forward the miscible slug, increasing microscopic efficiency because the unswept reservoir area is a smaller injection [37].

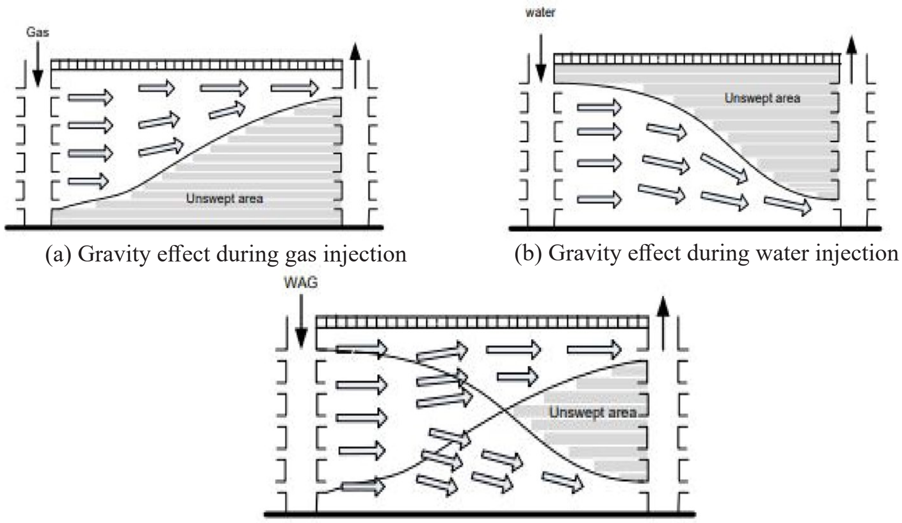
Figures 1(a), 1(b), and 1(c) demonstrate how the WAG injection may cover a larger region in the reservoir.

Most authors have conducted their studies considering CO_2 injection and sequestration into the gas reservoir to enhance gas recovery and reduce CO_2 levels in the atmosphere.

On the other hand, this study evaluated not only the performance of CO_2 injection but also the performance of water flooding and WAG techniques.

The study steps are as follows: Firstly, we have developed the required model of the reservoir to carry out a simulation study. Secondly, a base case model has been created. Afterward, injection wells were placed in a varied geometric pattern. After that, the simulation run was performed for different enhanced gas recovery methods.

Finally, a conclusion has been provided with the performance comparison, and a suitable technique has been suggested among the recovery methods based on performances.



(a) Gravity effect during gas injection

(b) Gravity effect during water injection

(c) Gravity effect during the WAG injection

Fig. 1 The gravity effect during gas, water, and WAG injection [37].

Materials and Methods

Reservoir Model Development

The base reservoir model used in this study was built using the open-source data of an active field in Bangladesh, Titas Gas Field. It is composed of sandstone which has homogeneous layer-cake geology. Natural gas is stored in this reservoir at a depth of 8590 ft.

The general petro-physical properties of the reservoir used in the base model have been studied from work carried out in 2001 [38]. Cell distributions' width, length, and thickness were used to design and regulate the gas reservoir model. The geological model's dimensions were 16 grid blocks in the X direction, 10 grid blocks in the Y direction, and 3 grid blocks in the Z direction.

Lengths of the grid blocks in X, Y, and Z directions are taken as 165 ft, 264 ft, and 170 ft. Three grid blocks in the Z direction indicate A2, A3, and A4 sands, and the permeability of these sands are 200, 250, and 150 mD, respectively. The water saturation of A2, A3, and A4 sands is 0.36, 0.33, and 0.38, respectively. The porosity value for the whole reservoir is 0.2. In the model, different grid levels represented each geological layer. Reservoir pressure and temperature were initially set to 3000 psi and 190 ºF. Reservoir model parameters are shown in Table 1.

PVT properties of the reservoir model as a function of pressure are illustrated in Table 2.

The chart for relative permeability, saturation, and capillary pressure is outlined in Table 3.

In terms of gas/water contact, the reference depth of the reservoir, pressure, and temperature were calibrated to achieve the equilibrium initialization. This indicated the presence of a gas-water transition zone. As a result, the simulator would consider these values and stabilize the initial aquifer zone, which was assigned in the depths of the bottom cells in the gas reservoir model.

CO_2 injection at the reservoir model's gas–water contact could act as substitute support for pressure maintenance, allowing gas production to occur concurrently. Furthermore, the process was expected to improve displacement efficiency, resulting in a higher ultimate recovery factor. As a result, CO_2 injection at the reservoir model's gas–water contact could act as alternate support for pressure maintenance, allowing gas production to occur concurrently.

The initial composition, the formation of rock strata, and characteristics were all modeled using the "ECLIPSE 300" reservoir simulation software to analyze the effect of reservoir geology on future development strategies. In addition, all simulation models were run using the "GASWAT" option. The GASWAT option in ECLIPSE 300 enables you to use an equation of state to describe gas phase/aqueous phase equilibrium.

To get correct gas solubility's in the aqueous phase, the Peng Robinson equation of state is adjusted following the ideas of Soreide and Whitson. GASWAT is only available in two phases. The gas and water phases are implicitly asked while it is being utilized. This option does not allow you to replicate the oil phase.

If the term GASWAT is present, the keywords OIL, WATER, and GAS are unnecessary and will be disregarded.

The GASWAT option also allows specifying molar calorific values using the CALVAL keyword. Gas quality, calorific production rates, and total calorific output are computed and reported for wells and groups [39].

Table 1 Reservoir model parameters.

Property	Value
Reservoir type	Sandstone
Reservoir depth	8593 ft
Area (X-Y direction)	6.96×10^6 ft^2
Thickness (Z direction)	510 ft
Grids in X direction	16
Grids in Y direction	10
Grids in Z direction	3 (A2, A3, A4 layers)
Initial reservoir temperature	190 °F
Initial reservoir pressure	3000 psia

Table 2 Viscosity and formation volume factor (A sand).

Pressure(psia)	Bg (ref/scf)	μ_g(cp)	Bw (rb/stb)	μ_w(cp)
100	0.18316	0.01373	1.03217	0.3357
463.2	0.03849	0.014	1.03096	0.3357
826.3	0.02115	0.0144	1.02975	0.3357
1189.5	0.01440	0.01492	1.02854	0.3357
1552.6	0.01088	0.01553	1.02733	0.3357
1915.8	0.00873	0.01622	1.02612	0.3357
2278.9	0.00731	0.017	1.02491	0.3357
2642.1	0.00632	0.01783	1.0237	0.3357
3005.3	0.00559	0.0187	1.02249	0.3357
3475	0.00491	0.01986	1.02093	0.3357
3731.6	0.00463	0.0205	1.02007	0.3357
4094.7	0.00429	0.0214	1.01886	0.3357
4457.9	0.00403	0.0223	1.01766	0.3357
4821.1	0.00381	0.02318	1.01645	0.3357
5184.2	0.00362	0.02404	1.01524	0.3357
5547.2	0.00347	0.02488	1.01403	0.3357
5910.5	0.00334	0.0257	1.01282	0.3357
6273.7	0.00322	0.0265	1.01161	0.3357
6636.8	0.00312	0.02727	1.0104	0.3357
7000	0.00304	0.02803	1.00919	0.3357

Table 3 Relative permeability, Saturation (A sand).

Sw	Krw	krg
0.10000	0.00000	1.00000
0.17500	0.0036	1.00000
0.25000	0.00719	0.90472
0.32500	0.01079	0.66124
0.40000	0.01439	0.45303
0.47500	0.01798	0.28281
0.55000	0.02158	0.12056
0.62500	0.02518	0.0055629
0.70000	0.02877	0.00000
1.00000	0.04316	0.00000

The geological model was developed to optimize the initial gas recovery in place. Several dynamic reserve simulation models were built to find the best development plan and verify its robustness over the reserve uncertainty range. The initial component names in the gas mixture were reported as C1, C2, C3, and CO_2 in all cases. The mole fraction of the components was 0.9658, 0.0190, 0.0044, and 0.0108, respectively, as shown in Table 4.

Table 4 Components name and mole fractions.

Component Name	Mole fraction
C1	0.9658
C2	0.0190
C3	0.0044
CO_2	0.0108

Well-completion data are shown in Table 5. Production well P1 has been allocated in the A2 layer (Grid location: X, Y: 3, 3), and the P2 well was installed in the A4 layer (Grid location: X, Y: 13, 7). In injection cases, injection wells are placed linearly with the production wells. The reservoir data used in this study provides the production scenario of the reservoir from pressure of 7000 psi to 100 psi. For the simulation run in this study, this production is considered representative of the present time and the reservoir performance is predicted under three EGR techniques for the forthcoming 6 years.

Table 5 Well completion data.

Well	Type	X (ft)	Y (ft)	Completion (ft)	Layer
I-1	Injector	1320	1320	8933-9103	A4
P-1	Producer	495	792	8593-8763	A2
P-2	Producer	2145	1848	8593-9103	A2, A3, A4

Base Case Simulation

The base case development plan calls for two vertical production wells, P1 and P2, allocated at A2 and A4 layers. These production wells were expected to produce natural gas at 17000 MSCFD and 23000 MSCFD for P1 and P2, which are the present production rates of the gas field. The average wellhead pressure for each well was set to 845 psi to maintain the smooth delivery of the producing gas to the gas processing plant. The production wells were generally controlled as a function of a maximum gas production rate per day and a minimum producing average bottom whole pressure for each well. In this case, this study investigated how long natural production occurred without injecting any fluid. Cumulative production was also observed for this base case. This base case has been compared with other cases in this study. The simulation results are shown in Figures 1 to 3.

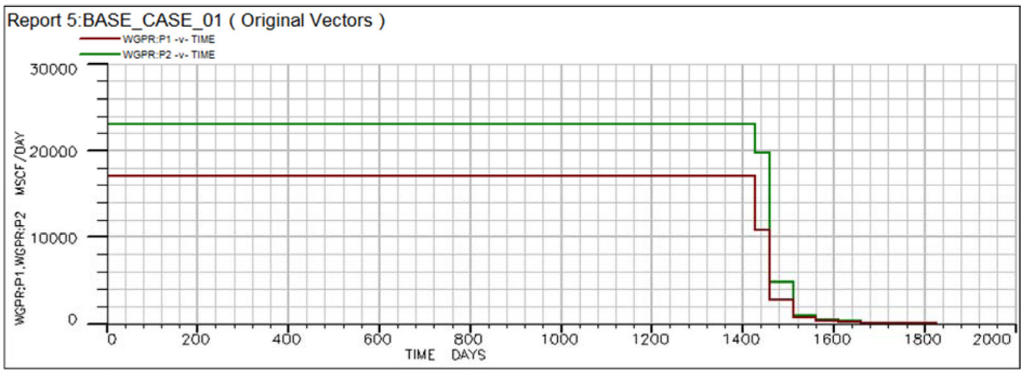


Fig. 2 Individual well gas production rate.

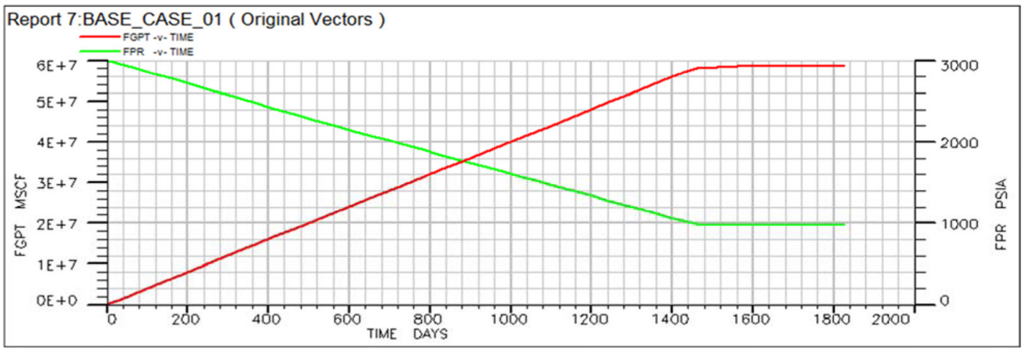


Fig. 3 Field gas production total (FGPT) vs. Field reservoir pressure (FPR).

Figure 2 shows the Well Gas Production Rate (WGPR) for production wells P1 and P2, which were set to 17000 MSCFD and 23000 MSCFD, respectively. The graph shows the natural production scenario of the production wells P1 and P2 without injecting fluid into the reservoir. If production rates are kept constant, the two wells continue their natural production for 1430 days. Cumulative gas production was observed at 58609952 MSCF over time, as shown in Figure 3. Reservoir pressure declined at a negative slope over time as the production rate maintained constant. All the simulations were run for 6 years or 1825 days.

Field gas quality (FGQ) of the producing gas was observed with respect to the calorific value of methane (12475 Btu/lb or 1033 Btu/scf). In Figure 4, the quality of the producing gas over the simulation period is shown. The gas quality was good as it was above 12000 Btu/lb over the period.

Effect of Injection Well Placement On Sweep Efficiency

Sweep efficiency depends on the placement of the injection well. Gas recovery largely depends on the sweep efficiency of the injected fluid. Gas recovery increases with the increase of swept volume. Therefore, this study analyses three injection well placement techniques to understand the optimum sweep efficiency.

3D modeling is the best way to understand injection well placement and sweep efficiency. 3D modeling of the reservoir is generated by CMG reservoir simulator software, as seen in Figure 5. As the 3D modeling option was not supported in the version of Eclipse software used in this study, so CMG reservoir simulator software was only used to generate 3D modeling and to investigate the effect of injection well placement properly, and the rest of the simulations of this study was run in Eclipse reservoir simulator software.

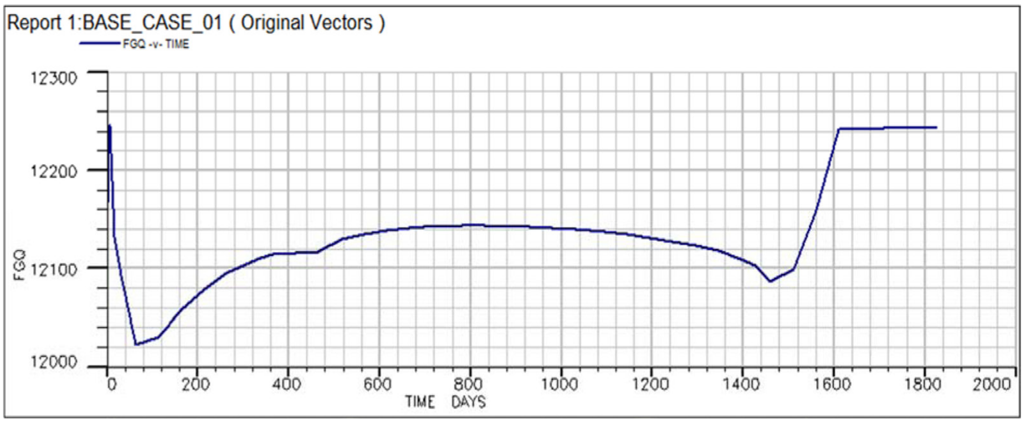


Fig. 4 Field gas quality.

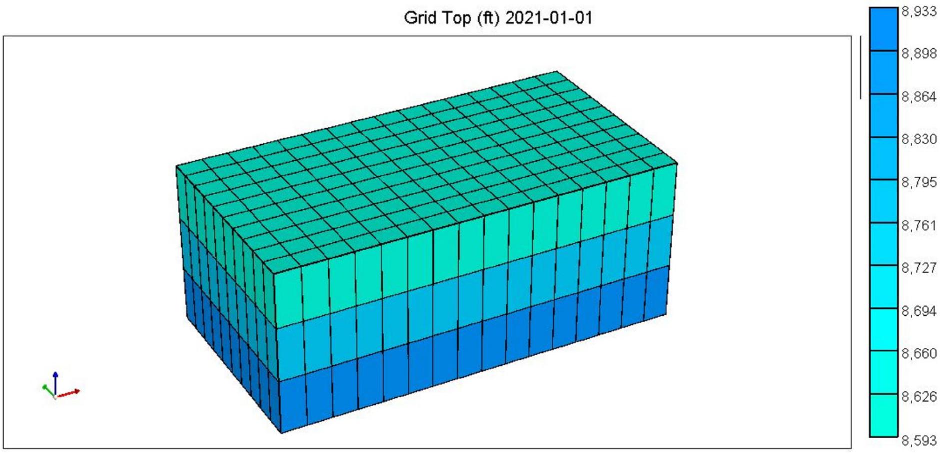


Fig. 5 3D view of the reservoir model.

Linear Placement

In this case, the injection well is placed linearly with the production wells, as seen in Figure 6. Injected well is perforated at the center of the two production wells. The simulation result showed that linear placement of injection well was swept 84.4% of the grid blocks.

Triangular Placement

Triangular placement refers to the placement of the injection well so that it makes a triangle shape with the production wells, as seen in Figure 7.

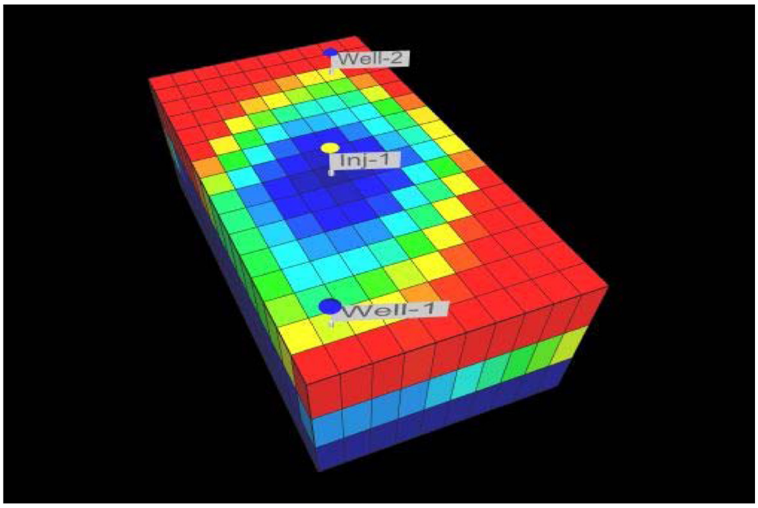


Fig. 6 Linear placement of injection well.

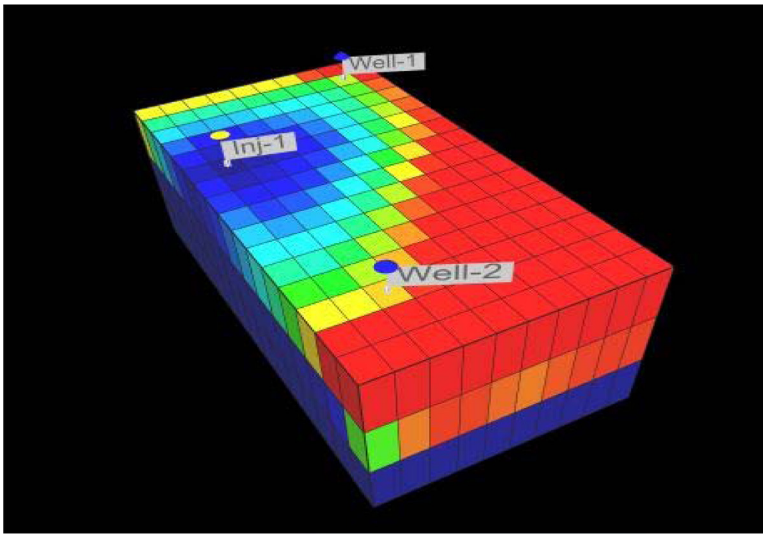


Fig. 7 Triangular placement of injection well.

The simulation result showed that the triangular placement of the injection well was swept 82.8% of the grid blocks.

Corner Placement

In this case, an injection well is placed at a corner of the reservoir (as seen in Figure 8).
The simulation result showed that the Corner placement of the injection well was swept 57.8% of the grid blocks.
Linear placement of the injection well showed a maximum sweep efficiency of 84.4% over Triangular placement (82.8%) and Corner placement (57.8%). Therefore, for further simulations, the linear placement of the injection well has been considered as well placement method in this study.

Fluid Models

The gas recovery depends on the injected fluid; different fluids behave differently in the reservoirs. This study considered water, CO_2, and alternating water gas as injection fluids.
For fluid injecting models, reservoir properties were maintained as same as the base case. As the reservoir passed its depletion phase, in fluid injection models, it was tried to find out the performance of EGR methods. The models' performances were evaluated by analyzing cumulative gas production, duration of the production period, and quality of the producing gas.

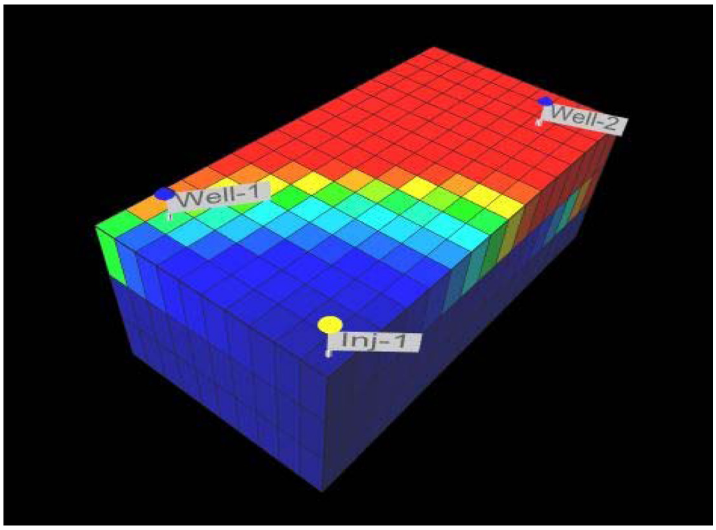


Fig. 8 Corner placement.

Water Flooding Model

The waterflooding model development plan calls for two vertical production wells and an injection well. Production wells placement is the same as the base case. An injection well was installed at the location of 8, 5, 1-3 for X, Y, and Z directions, respectively, for fluid injection purposes. In this case, water was injected as an injection fluid. The sensitivity of the water injection rate was analyzed by injecting water at 10000 STB/D, 12000 STB/D, and 13000 STB/D for 6 years. Finally, the water injection rate was set to 12000 STB/D. The simulation was run for 6 years, and outputs were compared to the base case. Simulation results are shown in Figures 9 to 13. From the flooding profile, it was found that 10000 STB/D of water injection rate could not flood the maximum area of the reservoir. At 13000 STB/D, water production was observed from the producing well. Both the problems from the above-mentioned injection rate were solved when the water injection rate was set to 12000 STB/D (Figure 10).

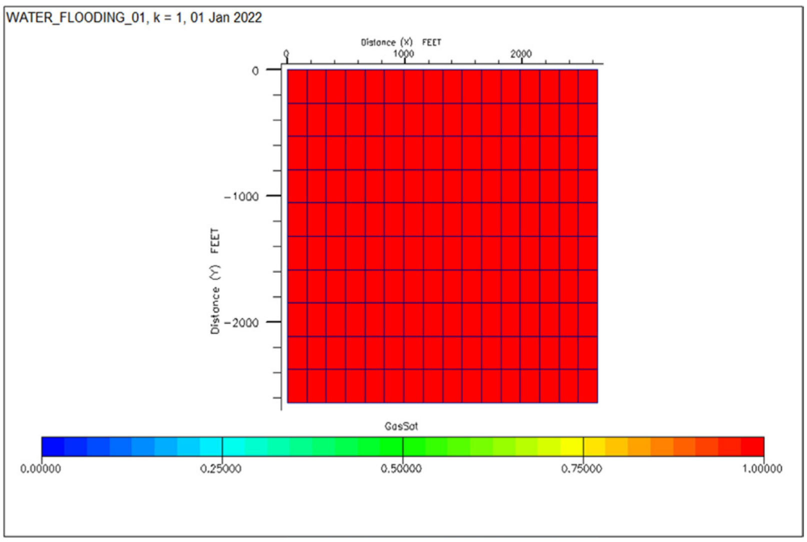


Fig. 9 Gas saturation before water flooding.

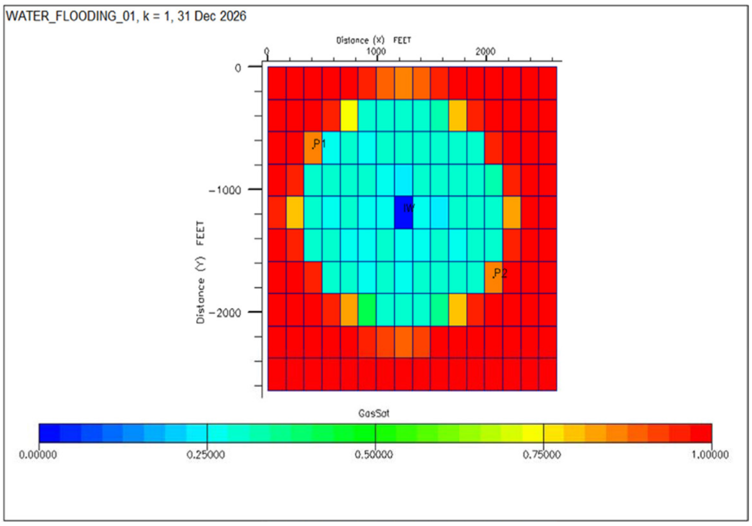


Fig. 10 Gas saturation after water flooding.

Injecting water at a constant rate of 12000 STB/D enhances the production period for two wells up to 1670 days, as shown in Figure 11, where base case production was continued for 1430 days at the given production rates. Production from both wells then declined noticeably. Production wells P1 and P2 were produced at 2311 MSCFD and 2942 MSCFD, as shown in Table 6 at the end of the simulation period.

Injecting water at a constant rate of 12000 STB/D enhances the production period for two wells up to 1670 days, as shown in Figure 11, where base case production was continued for 1430 days at the given production rates. Production from both wells then declined noticeably. Production wells P1 and P2 were produced at 2311 MSCFD and 2942 MSCFD, as shown in Table 6 at the end of the simulation period.

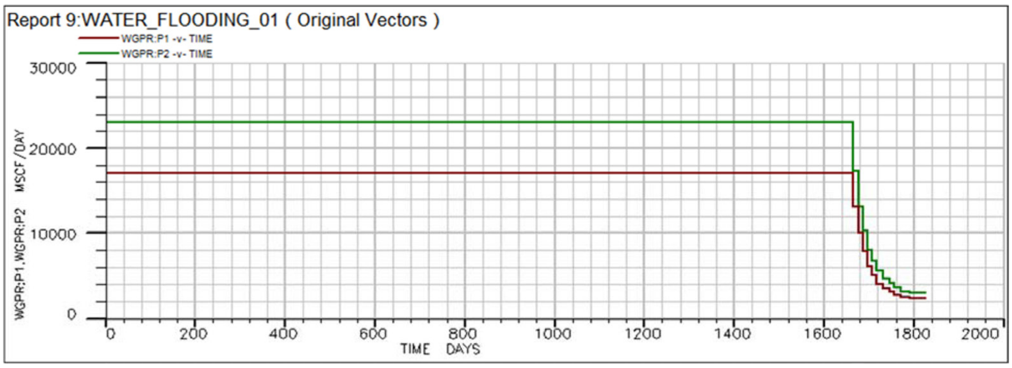


Fig. 11 Well gas production rate (WGPR) for P1 and P2.

Table 6 Well gas production rate (WGPR) and field gas production total (FGPT) for waterflooding case from the software for the last phase of the simulation.

Time (Days)	WGPR:P1(MSCF/D)	WGPR:P2(MSCF/D)	FGPT(MSCF)
1706	6112.73	8021.14	67484600
1715	4979.92	6744.69	67592704
1730	4058.1	5497.82	67736048
1745	3568.02	4719.08	67860352
1755	3150.55	4145.32	67933312
1771	2704.97	3611.69	68034376
1790	2459.53	7178.86	68141504
1807	2309.97	3003.31	68231832
1816	2347.45	2959.32	68276992
1825	2311.32	2942.94	68321696

The waterflooding model enhanced the total recovery as compared to the base case. A total of 68321696 MSCF gas was produced during the production period, as shown in Figure 12. As a result, gas recovery is 16.57% higher in the water flooding model compared to the base case model.
Field gas quality (FGQ) of the producing gas was observed concerning the field water production rate (FWPR). Gas quality and water production rate show an inversely proportional relationship. Gas quality declined while the water production rate increased, as shown in Figure 13. The water production rate could be controlled by optimizing the water injection rate.

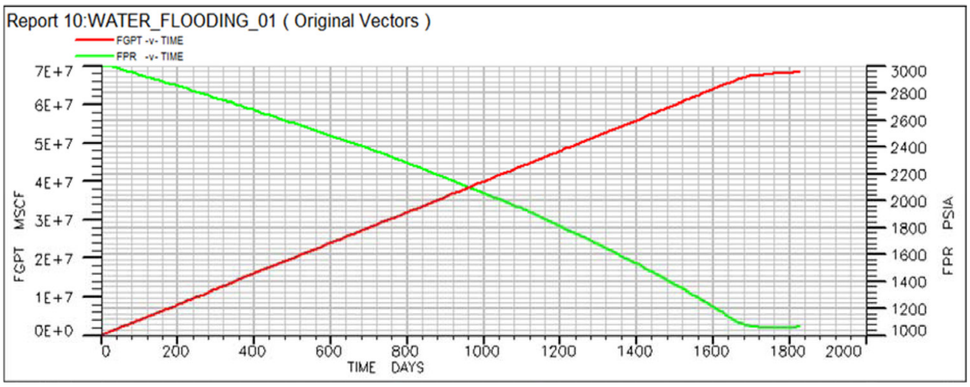


Fig. 12 Field gas production total (FGPT) with respect to reservoir pressure (FPR).

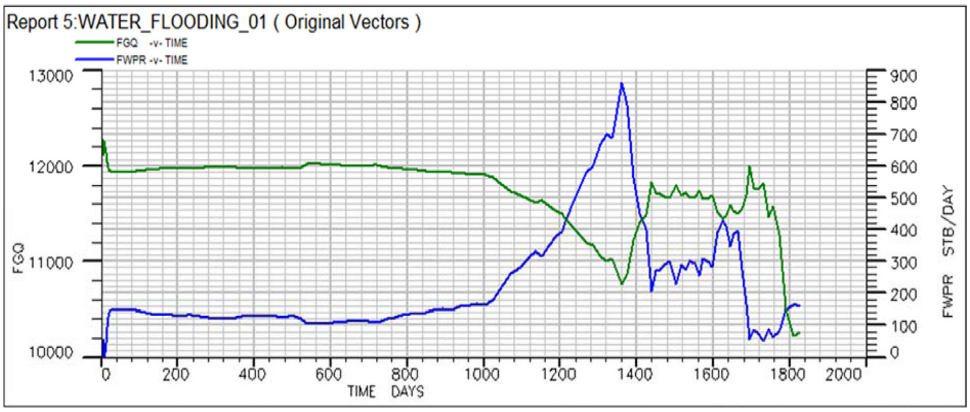


Fig. 13 Field gas quality (FGQ) and field water production rate (FWPR).

CO_2 Injection Model

The injection model development plan calls for two vertical production wells and an injection well like the water flooding model. In this case, CO_2 gas was injected as an injection fluid. The MISCIBLE keyword was used for miscible CO_2 injection reservoirs. The model was validated by comparing the "minimum miscibility pressure" (MMP) obtained from the result with MMP correlation methods.
The CO_2 gas injection rate was set to 12000 MSCFD after a thorough sensitivity analysis of different gas injection rates. Accurate estimation of MMP for CO_2 flooding can significantly improve reservoir recovery.
With an estimation of MMP, the miscible injection was proven to increase the gas recovery with injection pressure between 3000 psi and 3600 psi, where MMP was at 3000 psi. The simulation was run for 6 years, and outputs were compared to the base case. Simulation results are shown in Figures 14 to 16. Field gas production total (FGPT) for CO_2 flooding from the software for the last phase of the simulation is shown in Table 7.

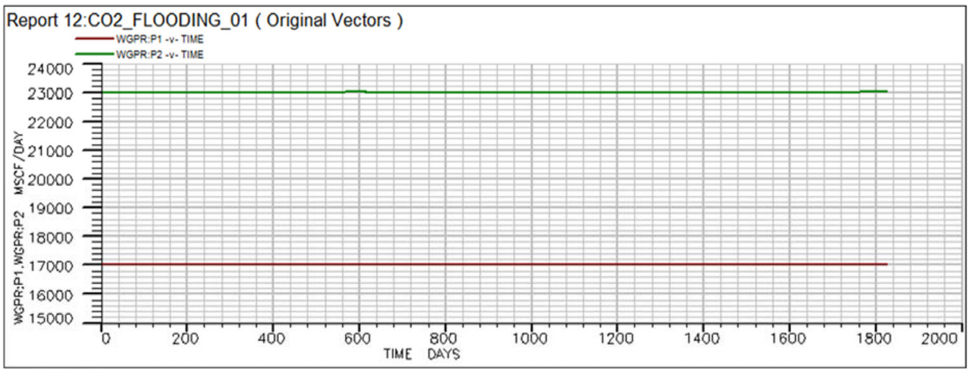


Fig. 14 Well gas production rate (WGPR) for well P1 and well P2.

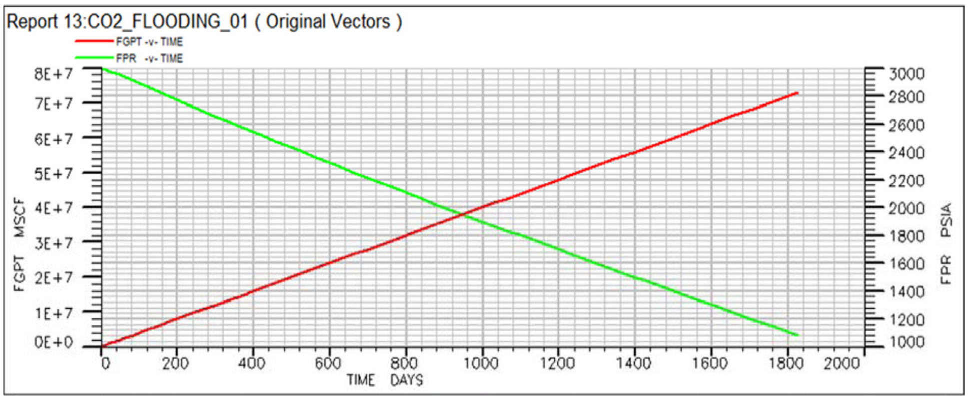


Fig. 15 Field gas production total (FGPT) and Field reservoir pressure (FPR).

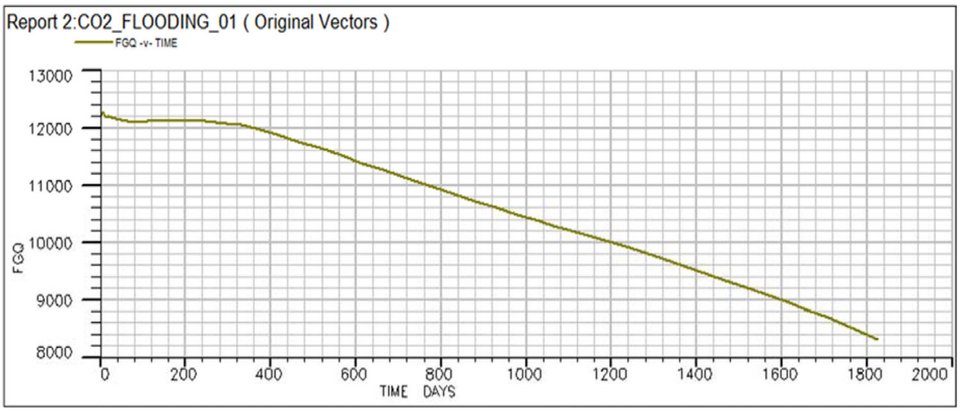


Fig. 16 Field gas quality (FGQ)

Table 7 Field gas production total (FGPT) for CO_2 flooding from the software for the last phase of the simulation.

Time (Days)	FGPT (MSCF)
1427.5	57400412
1640	56400412
1510	60400412
1560	6200412
1610	64400412
1660	66400412
1710	68401144
1760	70401144
1792.5	71701336
1825	73001512

Injecting CO_2 gas at a constant rate of 12000 MSCFD enhances the production period for both the wells up to the whole simulation period, as shown in Figure 14, where base case production continue for 1430 days, and water flooding case contributed for 1670 days at the given production rates. In CO_2 injection, cumulative production was found to be 73001512 MSCF gas for the 6 years simulation period, as shown in Figure 15. CO_2 injection enhanced 24.55% gas recovery compared to the base case, where water flooding contributed 16.57%.

Figure 16 shows the produced gas quality of the CO_2 injection model. Gas quality decreased with time. Gas quality was above 12000 Btu/lb up to 380 days. Then the curve showed a negative slope behavior.

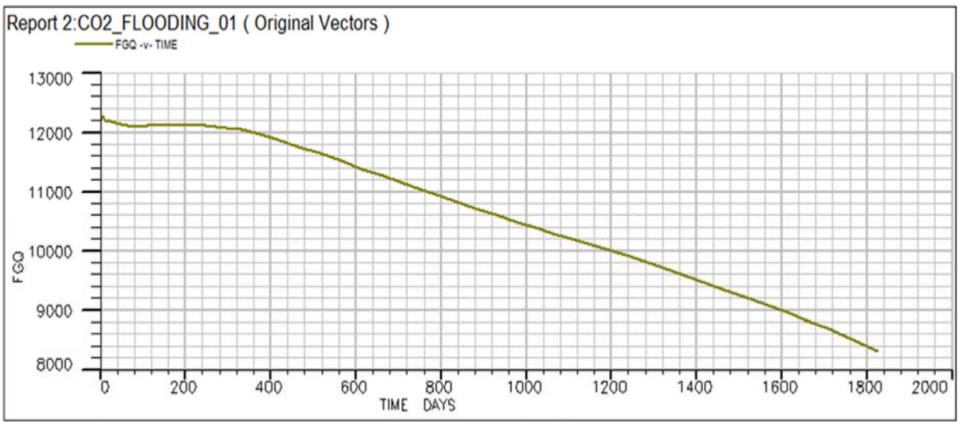


Fig. 16 Field gas quality (FGQ).

The degradation of gas quality indicates the breakthrough of CO_2 to the production well and gas-gas mixing scenario, which was responsible for the lower quality of producing gas. Optimization of injection well placement and perforation could effectively increase gas quality.

WAG Model

The WAG flooding model development calls for two vertical production wells and an injection well, the same as the water flooding model. Water and CO_2 gas were injected as an injection fluid. This model investigated the effect of the WAG ratio by running 3 cases: 1:1, 1:2, and 2:1. From the simulation, it observed that 1:1 produced the highest gas production, where equal water and gas were injected for maximum recovery. Since this is a miscible reservoir, an equal WAG ratio is more efficient and insensitive to trapping. The effect of WAG cycle time was explored using three scenarios: 180 days, 270 days, and 360 days. The favorable cycle period is 180 days. Because it is better to inject CO_2 and water in the shortest amount of time with the fewest number of cycles where reservoir miscibility is obtained when pressure is above minimum miscibility pressure.Water was injected at 12000 STB/D for the first 6 months, CO_2 was injected at 12000 MSCF for the next 6 months, and that cycle was repeated for the left simulation period. The primary purpose of the WAG process was to keep the water as the leading front to delay the CO_2 breakthrough that occurred in the previous CO_2 injection model. Simulation results are shown in Figures 17 to 20.

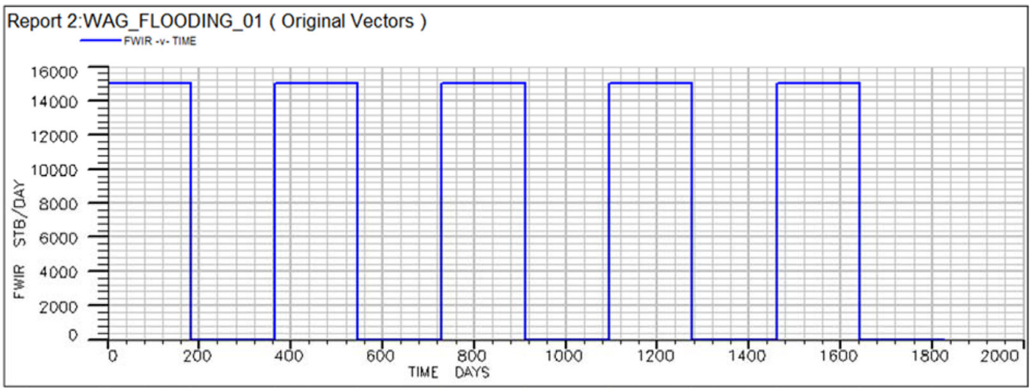


Fig. 17 Field water injection rate (FWIR).

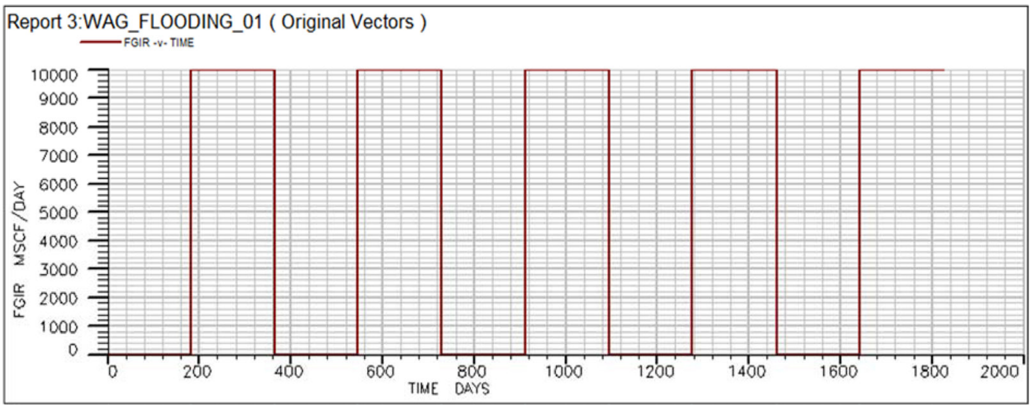


Fig. 18 Field gas injection rate (FGIR).

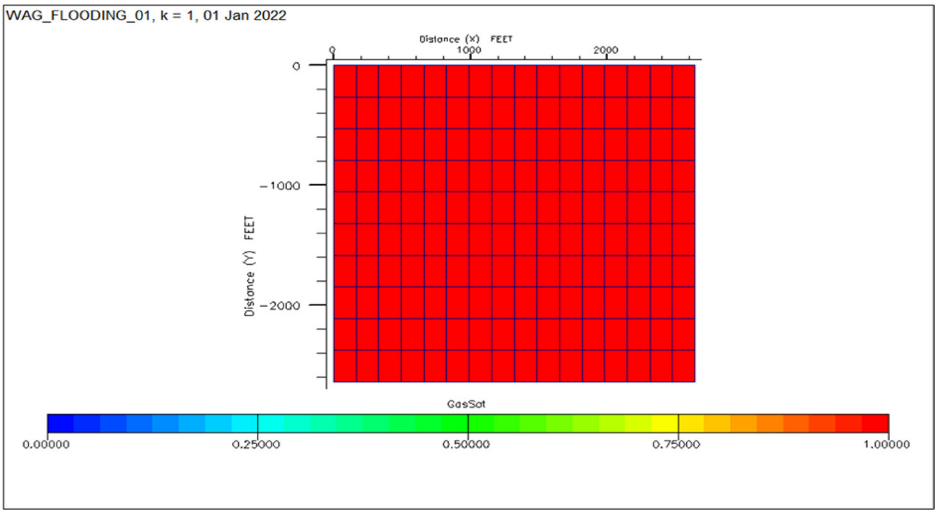


Fig. 19 Gas saturation before WAG flooding.

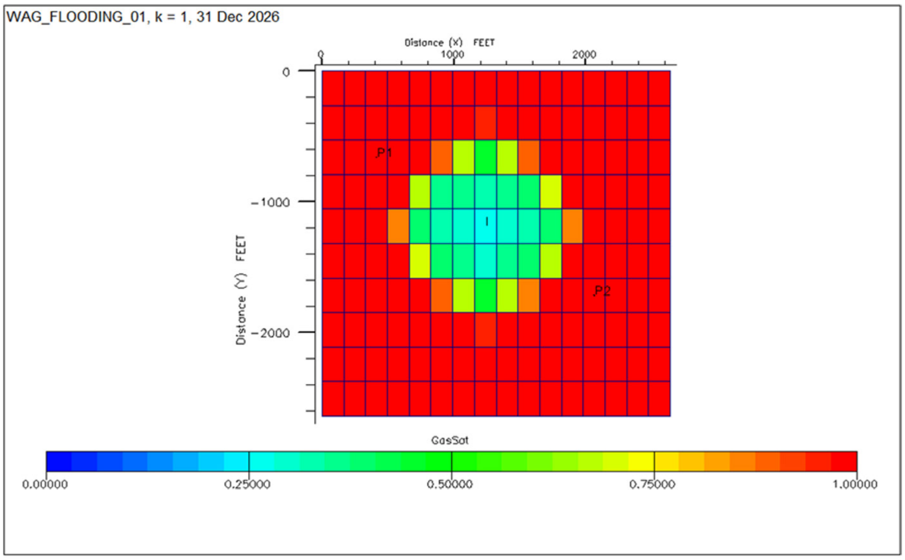


Fig. 20 Gas saturation after 6 years of production.

Well P1 continued its constant production rate up to 1560 days, then fell gradually, and well P2 continued its production rate up to 1545 days, followed by P1 well, as shown in Figure 21.

Cumulative gas production from the WAG flooding model was obtained at 63302068 MSCF, as shown in Figure 22, which is only 8% higher than the base case.

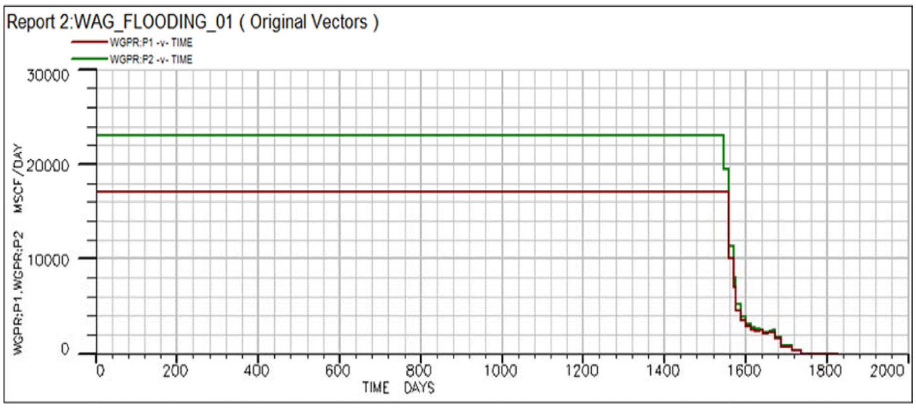


Fig. 21 Well gas production rate (WGPR).

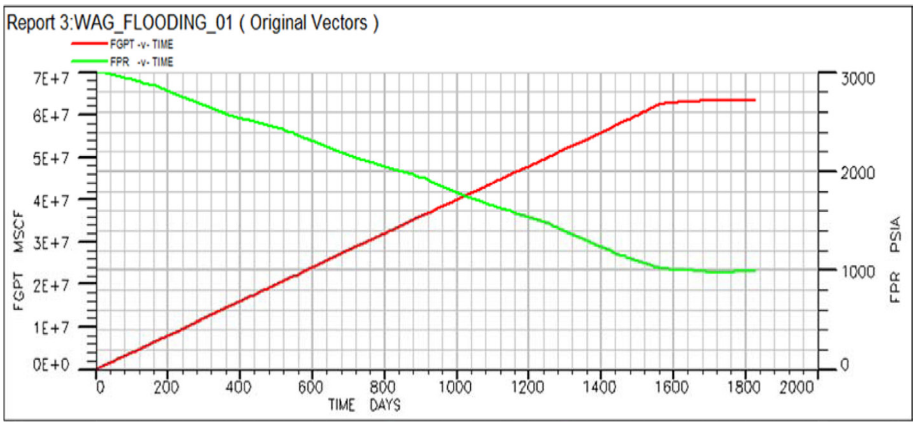


Fig. 22 Field gas production total (FGPT).

Production from two wells came to nil after 1737 days of production. There was no production from both wells for the last 100 days (Table 8).

Gas quality was excellent during the production period. WAG flooding model showed better performance in gas quality over other models. Gas quality was found to be above 12000 Btu/lb for the maximum period (as seen in Figure 23).

Table 8 Cumulative production data for the WAG model from the software for the last phase of the simulation.

Time (Days)	FGPT (MSCF)
1642	63058340
1654	63109896
1662	63147088
1672	63195032
1688	63247568
1715	63288072
1737	63302868
1767	63302068
1796	63302068
1825	63302068

Results and Discussion

This simulative study tries to determine the performance of three EGR techniques on a simulated reservoir model of a depleted gas reservoir and suggest the most suitable EGR technique among the three methods from the comparative analysis of the performance. Water flooding, CO_2 flooding, and the WAG model were investigated and compared to base case results. The development of the base case model is based on the current situation of the gas field. In the base case model, the reservoir has produced through the natural driving force of the reservoir. Therefore, no additional fluid was injected into the reservoir during this period.

On the other hand, fluid models have been developed with the injection of injected fluid in the reservoir. In fluid model cases, an additional driving force has been developed in the reservoir due to the injected fluid, which resulted in additional gas recovery. In addition, gas recovery largely depends on the sweep efficiency of the injected fluid. Therefore, the fluid model has been analyzed based on two factors:

a) Gas recovery percentage/ cumulative gas production.

b) Field gas quality of producing gas.

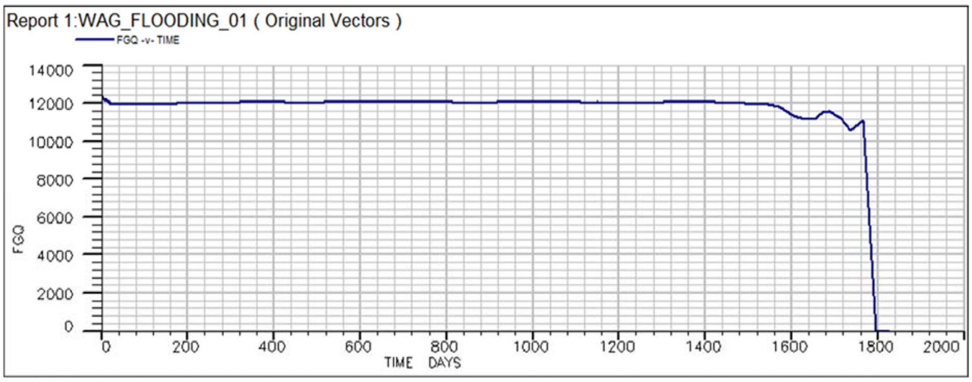


Fig. 23 Field gas quality (FGQ).

Gas Recovery Percentage/Cumulative Gas Production

Gas recovery increase in the fluid models was calculated considering base case gas recovery. The formula used to calculate the gas recovery of the fluid model is given in Equation 1. The CO_2 model showed the highest gas recovery in comparison with the base case over other models.

$$\text{Enhanced Gas Recovery, \%} = \frac{FMCP - BMCP}{BMCP} \times 100\% \quad (1)$$

where,

$FMCP$ = Fluid model cumulative production

$BMCP$ = Base case model cumulative production

The simulations were run for 1825 days (5 years) for each case scenario. In the base case model, when no fluid was injected, cumulative gas production was 58609952 MSCF which is used as a reference value to calculate the increment of gas recovery from fluid models. On the other hand, the water flooding model produced 68321696 MSCF gases which is 16.57% more gas recovery than the base case model after the simulation period. Regarding the CO_2 flooding model, the model outperformed both models by producing 24.55% more gas than the base case model, while the WAG model showed only 8% more gas recovery compared to the base case (Table 9).

Field Gas Quality of Producing Gas

Field gas quality (FGQ) of the producing gas was observed with respect to the calorific value of methane (12475 Btu/lb or 1033 Btu/scf). The WAG flooding model showed the best performance in maintaining gas quality, above 12000 Btu/lb, for the maximum production period. On the other hand, the CO_2 flooding model showed lower gas quality due to gas-gas mixing; the gas quality can be improved by optimizing well perforation. Moreover, the water flooding model showed an excellent gas quality curve. The gas quality of the water flooding model can be maintained by optimizing water production.

Table 9 Fluid model's gas recovery percentage

Model Name	Cumulative gas production (MSCF)	Enhanced gas recovery %
Base case model	58609952	-----
Water flooding model	68321696	16.57%
CO_2 flooding model	73001512	24.55%
WAG flooding model	63302068	8.00%

Conclusions

This research aimed to evaluate several EGR methods' performance in injection well locations in a depleted gas reservoir. CO_2 injection for increased gas recovery and CO_2 sequestration in depleted gas reservoirs were the focus of most of the studies in this literature. On the other hand, this study included comparing the performance of water floods and the WAG model with CO_2 performance and suggested the most suitable EGR technique among them. The findings of the study are:

• According to simulation data, linear injection well placement has a maximum sweep efficiency of 84.4 percent, triangular placement has a maximum sweep efficiency of 82.8 percent, and corner placement has a maximum sweep efficiency of 57.8 percent. Linear placement of the injection well performed greater sweep efficiency over triangular placement and corner placement of the injection well.

• It was found that the CO_2 injection model contributed 24.55 percent more gas recovery than the base case model. However, the model showed a poor gas quality curve due to CO_2 breakthrough and gas-to-gas mixing in the well. Therefore, optimizing the well perforation could be an excellent strategy to keep the desired gas quality. On the other hand, the WAG model maintained outstanding gas quality throughout the production period and yielded only 8% more gas than the base case scenario. The reason behind a poor gas recovery in the WAG model was the smaller flooded area of the reservoir (Figure 20). Due to the cyclic injection of water and CO_2 gas, flood font velocity was not uniform, resulting in a smaller flooded area. Furthermore, water flooding outperformed the base case model by 16.57 percent when it came to increasing gas recovery and preserving decent gas quality.

• Finally, by analyzing the performances of three EGR techniques, this simulation study suggests the CO_2 injection model as the most suitable EGR technique over the water flooding and WAG models in terms of more gas recovery. The development of gas quality by optimizing the well performance will be the future work of this study.

References

1. https://www.eia.gov/outlooks/ieo/pdf/ieo2019.pdf (DOA: 28/12/2022)
2. Özkılıç Ö İ (2005) Simulating CO_2 sequestration in a depleted gas reservoir, Master's thesis, Middle East Technical University.
3. Algharaib M, Al-Soof NA (2008) Economical modeling of CO_2 capturing and storage projects, In SPE Saudi Arabia Section Technical Symposium, OnePetro
4. Câmara G, Andrade C, Júnior A S, Rocha P (2013) Storage of carbon dioxide in geological reservoirs: is it a cleaner technology?, Journal of Cleaner Production, 47, 52-60.
5. Hasan M F, First E L, Boukouvala F, Floudas C A (2015) A multi-scale framework for CO_2 capture, utilization, and sequestration: CCUS and CCU, Computers and Chemical Engineering, 81, 2-21.
6. Xie H, Li X, Fang Z, Wang Y, Li Q, Shi L, Hou Z (2014) Carbon geological utilization and storage in China: current status and perspectives, Acta Geotechnica, 9, 1: 7-27.
7. Luu M T, Milani D, Abbas A (2016) Analysis of CO_2 utilization for methanol synthesis integrated with enhanced gas recovery, Journal of Cleaner Production, 112: 3540-3554.
8. Van der Burgt M J, Cantle J, Boutkan V K (1992) Carbon dioxide disposal from coal-based IGCC's in depleted gas fields, Energy Conversion and Management, 33, 5-8: 603-610.
9. Abba M K, Al-Othaibi A, Abbas A J, Nasr G G, Mukhtar A (2018) Experimental investigation on the impact of connate water salinity on dispersion coefficient in consolidated rocks cores during Enhanced Gas Recovery by CO_2 injection, Journal of Natural Gas Science and Engineering, 60: 190-201.
10. Oldenburg C M, Benson S M (2002) CO_2 injection for enhanced gas production and carbon sequestration, In SPE International Petroleum Conference and Exhibition in Mexico, OnePetro.
11. Shtepani E (2006) CO_2 sequestration in depleted gas/condensate reservoirs, In SPE Annual Technical Conference and Exhibition, Society of Petroleum Engineers.
12. Turta A T, Sim S S, Singhal A K, B. F. Hawkins (2008) Basic investigations on enhanced gas recovery by gas-gas displacement, Journal of Canadian Petroleum Technology, 47: 10.
13. Sim S S K, Brunelle P, Turta A T, Singhal A K (2008) Enhanced Gas Recovery and CO_2 Sequestration by injection of exhaust gases from combustion of bitumen, In SPE Symposium on Improved Oil Recovery, OnePetro.
14. Sim S S K, Turtata A T, Singhal A K, Hawkins B F (2009) Enhanced gas recovery: Factors affecting gas-gas displacement efficiency, Journal of Canadian Petroleum Technology, 48, 08: 49-55.
15. Al-Abri A S, Amin R (2009) Enhanced natural gas and condensate recovery by injection of pure SCCO2, pure CH_4 and their mixtures: experimental investigation, In SPE Annual Technical Conference and Exhibition, OnePetro.
16. Hughes T J, Honari A, Graham B F, Chauhan A S, Johns M L, May E F (2012) CO_2 sequestration for enhanced gas recovery: New measurements of supercritical CO_2–CH_4 dispersion in porous media and a review of recent research, International Journal of Greenhouse Gas Control, 9, 457-468.
17. Honari A, Hughes T J, Fridjonsson E O, Johns M L, May E F (2013) Dispersion of supercritical CO_2 and CH_4 in consolidated porous media for enhanced gas recovery simulations, International Journal of Greenhouse Gas Control, 19: 234-242.
18. Sidiq H, Amin R, Van der Steen E, Kennaird T (2011) Super critical CO_2–methane relative permeability investigation, Journal of Petroleum Science and Engineering, 78, 3-4: 654-663.
19. Khan C, Amin R, Madden G (2013) Carbon dioxide injection for enhanced gas recovery and storage (reservoir simulation), Egyptian Journal of Petroleum, 22, 2: 225-240.
20. Zhang Y, Liu S, Song Y, Zhao J, Tang L, Xing W,

Zhan Y (2014) Experimental investigation of CO_2-CH_4 displacement and dispersion in sand pack for enhanced gas recovery, Energy Procedia, 61: 393-397.
21. Patel M J, May E F, Johns M L (2016) High-fidelity reservoir simulations of enhanced gas recovery with supercritical CO_2, Energy, 111: 548-559.
22. Hussen C, Amin R, Madden G, Evans B (2012) Reservoir simulation for enhanced gas recovery: an economic evaluation, Journal of Natural Gas Science and Engineering, 5: 42-50.
23. B Van der Meer (2005) Carbon dioxide storage in natural gas reservoir, Oil and gas science and technology, 60, 3: 527-536.
24. Feather B, Archer R (2010) Enhanced natural gas recovery by carbon dioxide injection for storage purposes, In 17th Australia Fluid Mechanics Conference held in Auckland, New Zealand, 1-4.
25. Al-Hasami A, Ren S, Tohidi B (2005) CO_2 injection for enhanced gas recovery and geo-storage: reservoir simulation and economics, In SPE Europec/EAGE Annual Conference, OnePetro.
26. Oldenburg C M, Pruess K, Benson S M (2001) Process modeling of CO_2 injection into natural gas reservoirs for carbon sequestration and enhanced gas recovery, Energy and Fuels, 15, 2: 293-298.
27. Oldenburg C M, Stevens S H, Benson S M (2004) Economic feasibility of carbon sequestration with enhanced gas recovery (CSEGR), Energy, 29, 9-10: 1413-1422.
28. Aminu M D, Nabavi S A, Rochelle C A, Manovic V (2017) A review of developments in carbon dioxide storage, Applied Energy, 208: 1389-1419.
29. Blok K, Williams R H, Katofsky R E, Hendriks C A (1997) Hydrogen production from natural gas, sequestration of recovered CO_2 in depleted gas wells and enhanced natural gas recovery, Energy, 22, 2-3: 161-168.
30. Liu S, Agarwal R, Sun B, Wang B, Li H, Xu J, Fu G (2021) Numerical simulation and optimization of injection rates and wells placement for carbon dioxide enhanced gas recovery using a genetic algorithm, Journal of Cleaner Production, 280: 124512.
31. Hamza A I A. Hussein M J, Al-Marri Mahmoud M, Shawabkeh R, Aparicio S (2021) CO_2 enhanced gas recovery and sequestration in depleted gas reservoirs: A review, Journal of Petroleum Science and Engineering, 196: 107685-107689.
32. Du X, Gu M, Liu Z, Zhao Y, Sun F, Wu T (2019) Enhanced shale gas recovery by the injections of CO_2, N2, and CO_2/N_2 mixture gases, Energy and Fuels, 33, 6: 5091-5101.
33. Mohammed N, Abbas A J, Enyi G C, Suleiman S M, Edem D E, Abba M K (2020) Alternating N_2 gas injection as a potential technique for enhanced gas recovery and CO_2 storage in consolidated rocks: an experimental study, Journal of Petroleum Exploration and Production Technology, 10, 8: 3883-3903.
34. Arcaro D P, Bassiouni Z A (1987) The technical and economic feasibility of enhanced gas recovery in the eugene island field by use of the coproduction technique, Journal of petroleum technology, 39, 05: 585-590.
35. Cuderman J F, Northrop D A (1986) A propellant-based technology for multiple-fracturing wellbores to enhance gas recovery: application and results in Devonian shale, SPE Production Engineering, 1, 02: 97-103.
36. Cason L D (1989) Waterflooding increases gas recovery, Journal of Petroleum Technology, 41, 10: 1102-1106.
37. Elsharafi M O (2018) Literature review of water alternation gas injection, Journal of Earth Energy Engineering, 7, 2: 33-45.
38. Tamim D (2001) Reserve estimate and development study of titas gas field, Dissertation/Theses - Department of Petroleum and Mineral Resources Engineering, doi: http://lib.buet.ac.bd:8080/xmlui/handle/123456789/1923.
39. Eclipse Reference Manual, 2010.