Computational Water, Energy, and Environmental Engineering, 2025, 14(1), 1-15
https://www.scirp.org/journal/cweee
ISSN Online: 2168-1570
ISSN Print: 2168-1562

Near Gas-Water Contact Sequestration of Carbon Dioxide to Improve the Performance of Water Drive Gas Reservoir: Case Study

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How to cite this paper: Safarzadeh, M.A., Zangeneh, H. and Kasravi, J. (2025) Near Gas-Water Contact Sequestration of Carbon Dioxide to Improve the Performance of Water Drive Gas Reservoir: Case Study. *Computational Water, Energy, and Environmental Engineering*, **14**, 1-15.
https://doi.org/10.4236/cweee.2025.141001

Received: July 7, 2024
Accepted: December 3, 2024
Published: December 6, 2024

Abstract

This study investigates the application of carbon dioxide (CO_2) sequestration to address challenges in water-drive gas reservoirs, specifically focusing on improving gas recovery and mitigating water invasion. Traditional methods like blow-down and co-production have limitations, including sand production, water coning, and inefficiency in strong aquifers. To overcome these issues, this research explores CO_2 injection near the edge aquifer, aiming to reduce water influx and enhance gas recovery through the propagation of a CO_2 plume in the gas-water contact zone. Both synthetic and real compositional reservoir models were studied, with CO_2 injection performed while maintaining reservoir pressure below 90% of the initial level. Results show that CO_2 sequestration significantly improved recovery, particularly in higher permeability reservoirs, where it reduced aquifer influx and increased gas production by 26% under challenging conditions. While CO_2 dissolution in water decreased aquifer influx by 39%, its adverse effect on sweep efficiency led to a reduction in gas and water production by 4.2% and 10%, respectively. The method's effectiveness was not significantly impacted by aquifer permeability, but it was sensitive to vertical-to-horizontal permeability ratios. When applied to a real gas reservoir, the proposed method increased gas production by 14% compared to conventional techniques, with minimal CO_2 production over a 112-year period. This study demonstrates the potential of CO_2 sequestration as a comprehensive solution for enhancing gas recovery, reducing water production, and mitigating environmental impacts in water-drive gas reservoirs.

Keywords

Gas Reservoir, Water Encroachment, Residual Gas Saturation,

Aquifer Influx, Carbon Dioxide Sequestration, Hazardous Water Production

1. Introduction

Aquifer activity significantly influences recovery declines in water-drive gas reservoirs [1] [2]. Recoveries typically range from 35% to 75%, while depletion-drive reservoirs can achieve nearly 90% [3]. The ultimate recovery is governed by physical properties like residual gas saturation (Sgr) behind the water front [4] [5]. Sgr values vary from 0.1 to 0.7. As production increases and pressure drops, water invades gas-filled pores, leading to incomplete gas displacement. Capillary pressure and relative permeability effects can halt gas flow, allowing only water to pass through the rock [6]-[8]. Two techniques enhance recovery in gas reservoirs with aquifer support. The blow-down technique involves producing gas at a high rate to exceed water invasion rates, necessitating a pressure drop before aquifer response [9]. However, it may be ineffective in weak aquifers and can lead to water conning and sand production. An alternative, co-production, extracts water from downdip wells while producing gas from updip wells, which slows water influx and allows more time for gas production. In strong aquifers, increased water production may not significantly lower reservoir pressure, leading to low incremental recovery [7]. A major drawback is the production of hazardous water containing heavy metals, chemicals, and hydrocarbons [10] [11]. A systematic study by Agarwal *et al.* emphasized maximizing depletion practices for gas recovery and highlighted water influx as a critical factor in low efficiency [12]. Solutions for these gas reservoirs include depleting pore volume before water invasion or alleviating water influx. Li *et al.* proposed a new criterion for assessing aquifer activity levels and a method for establishing recovery variation ranges.

The CO_2 concentration trend reflects mostly energy-related human activities that, over the past decade, were determined by economic growth, mostly in developing countries [13]. The 2012 CO_2 concentration of 394 ppm was about 40% higher than in the mid-1800s, with an average growth of 2 ppm/year in the last ten years (2013). The main drawbacks of CO_2 emission reduction approaches vary in scope and impact. Renewable energy requires high upfront costs and faces intermittency challenges, while energy efficiency improvements can become costly and complex as they scale. Fuel switching still relies on fossil fuels and can result in methane leaks, limiting its long-term viability. Afforestation and reforestation require large land areas and take time to yield results while being vulnerable to environmental threats. Carbon pricing can encounter political resistance and may impose economic burdens on industries, depending on the price set [14] [15]. One of the effective solutions for decreasing the emission of CO_2 is direct capturing and storing in deep geological formations, which is known as Carbon Capture and Storage (CCS) [16]. In recent years, there has been an increasing interest in the development of gas reservoirs for the safe storage of CO_2. Several studies have reported on the numerical simulation and study of the CO_2 storage process, usually in order to establish more efficient schemes to store larger volumes of gas [17]-[19].

To investigate conventional CO_2 sequestration in gas reservoirs, Abba *et al*. demonstrated that water saturation and salinity significantly influence CO_2 displacement efficiency in methane reservoirs [20]. Honari *et al*. also measured fluid dispersion in rock cores at various saturations, finding that irreducible water can increase dispersivity by up to 7 [21]. This work introduces an alternative strategy involving CO_2 injection to mitigate water encroachment and enhance gas production in water-drive gas reservoirs. Applying this proposed method offers two potential advantages compared to routine CO_2 sequestration: it can promote the propagation of the CO_2 plume near the aquifer, thereby reducing aquifer influx, and it can significantly decrease hazardous water production. However, a major challenge of this method lies in monitoring the injection pressure to prevent fracturing. While existing studies underscore the efficiency and cost benefits of CO_2 storage in depleted reservoirs [22]. This research aims to further enhance recovery rates specifically in water-drive gas reservoirs. By focusing on optimizing recovery strategies, this work seeks to address challenges related to water encroachment while leveraging the advantages already established in the field of CO_2 sequestration.

2. Models Description

This study investigates the impact of aquifer activity on the performance of gas reservoirs through a series of simulation studies conducted on two compositional models: a synthetic model and a real case. **Figure 1** illustrates a 3D view of the models and their associated wells. Both CO_2 injection and water production wells featured a vertical main well and a horizontal sidetrack, while the other producing wells were vertical. The composition of the reservoir fluids is detailed in **Table 1**. For this study, a water-drive gas reservoir was designated as the Base Case. **Table 2** presents the static and dynamic properties of the two models under the Base Case scenario.

Table 1. Composition of reservoirs fluids.

Component	Mole Fraction (%)	
	Synthetic Model	Real Model
CO_2	0	2.6
C1	94.68	95.86
C_3C_4	5.32	0.71
C_5C_6	0	0.33
$C_{7+}(1)$	0	0.3952
$C_{7+}(2)$	0	0.1048

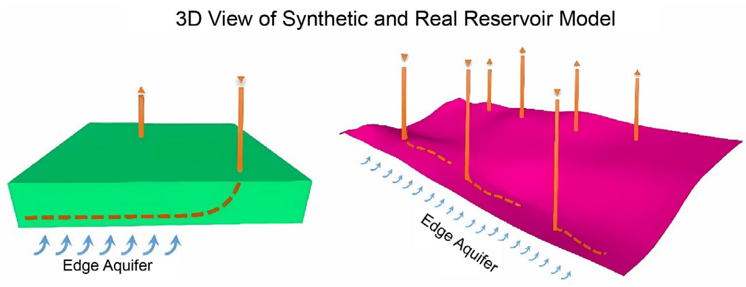

Figure 1. 3D view of reservoir models and their wells.

Table 2. Static and dynamic properties of two models for base case.

Property	Unit	Value	
		Synthetic Model	Real Model
Reservoir Length	m	3000	48196
Reservoir Width	m	3000	45627
Average Thickness	m	100	50.05
Temperature	˚C	93	127
Initial Pressure	bar	204	350
Average Porosity	%	10	3.3
Water/Gas Contact Depth	m	2090	2930
Average Vertical Permeability	md	1.4	1.6
Average Horizontal Permeability	md	7	16
Model Dimension	-	50 × 50 × 10	60 × 45 × 8
No. of Production Well	-	1	4
No. of Injection Well	-	1	3
Total CO_2 Injection Rate	MMSCMD	0.4	3.1
Simulation Time	Year	30	112
Maximum Water Cut	%	20	20
Total CO_2 Injected	MMMSCM	4.38	126
Aquifer Permeability	md	250	220
Aquifer Porosity	%	25	20
Angle of Influence	Degree	360	-
Bottom hole Pressure	bar	70	90

2.1. Synthetic Model

In the synthetic model, the horizontal injection well was positioned near the aquifer, while the production well was located at the center of half of the cubic model (see Figure 1). This heterogeneous reservoir model contained gas composed of three components, which was simulated using the Peng-Robinson equation of state. The properties of the reservoir rock were characterized using the Corey model, with a Corey index of 6 for gas and 4 for water. The reservoir featured an active edge-driven aquifer, modeled according to the Carter-Tracy model in the Base Case.

2.2. Real Case Model

The real case field produces 6 million standard cubic meters (MMSCM) of gas per day. Similar to the synthetic model, the horizontal injection wells were placed near the aquifer. The reservoir model contains gas with six components, which was modeled using the modified Peng-Robinson equation of state. The aquifer was represented using the Carter-Tracy model.

3. Production and Injection Scenarios

In this study, four cases were analyzed to investigate the effect of the aquifer on the performance of both synthetic and real cases. In the first case (Case I), the influence of the aquifer on the reservoir was suspended by deactivating it. The primary goal of this case was to determine the impact of the aquifer on reservoir performance.

In the second case (Case II), the production process was simulated under a depletion scenario, accompanied by the aquifer. Comparing Case I and Case II illustrates the effect of aquifer activity on water and gas production. The production conditions in this case are the same as in the first case, serving as the Base Case for production in the reservoir.

In the third case (Case III), a co-production technique was applied. Water production commenced in the initial years at optimized production rates of 10 million standard cubic meters (MSCM) for the synthetic model and 6 MSCM for the real case. Water was produced separately from a horizontal well located near the aquifer.

Finally, in the last case (Case IV), CO_2 sequestration was simulated to mitigate the effects of water encroachment in water-drive gas reservoirs. To enhance CO_2 sequestration, the injection process began in the early years of production. The maximum pressure allowed during this injection process was 0.90 of the initial pressure, controlled by the total injection rate of CO_2.

4. Results and Discussion

Gas production from a water-drive reservoir can trap significant gas in pore volumes. Injecting CO_2 into the adjacent water-gas contact can reduce aquifer influx and sweep more gas toward production wells. This study examined the effects of reservoir permeability, vertical-to-horizontal permeability ratio, aquifer properties, and CO_2 dissolution on a synthetic water-drive gas reservoir model, followed by application to a real case.

4.1. Synthetic Model

The study investigated the effects of reservoir permeability, the vertical-to-horizontal permeability ratio, aquifer properties (including permeability, radius, and initial pressure), and CO_2 dissolution.

4.1.1. Effect of Horizontal Permeability (Kxy)

Figure 2 illustrates the effect of reservoir permeability on cumulative gas production and water-cut for the four cases. The rate at which gas production increases with rising reservoir permeability differs between the cases. Notably, CO_2 injection near the aquifer (Case IV) achieves the highest gas recovery across all permeability values. For this range of permeabilities, gas recovery in the active aquifer case (Case II) decreases as permeability increases, compared to the inactive aquifer case (Case I). In other words, the negative impact of the aquifer becomes more pronounced as reservoir permeability increases. A similar trend in gas production vs. permeability is observed for both the Base Case (Case II) and CO_2 injection (Case IV).

In the conventional method (Case III), gas production diminishes with lower permeability compared to the active aquifer case (Case II). This is because, with higher permeability and the corresponding higher water-cut, the water influx is effectively controlled, allowing more time to deplete the reservoir. Although the conventional method improves gas production at a permeability of 7 md compared to the Base Case, the associated production of large volumes of water is undesirable. To further evaluate Case III, a reservoir permeability of 15 md was tested, revealing that Case III does not significantly enhance gas production relative to the 7 md permeability. Similarly, gas production in Case II does not increase significantly with higher permeability. The figure also shows that the water-cut in Case IV remains near zero. CO_2 injection sweeps the reservoir, reducing the water-invaded zone and enhancing gas recovery while maintaining reservoir pressure, which prevents water movement by limiting pressure drawdown. The amount of CO_2 produced is 0.9%, 1.4%, and 2.1% of the injected volume by the 30th year for reservoir permeabilities of 2, 5, and 7 md, respectively.

Additionally, the effect of permeability heterogeneity (with a standard deviation from 0.1 to 1.0) at 7 md was tested, showing no significant impact on gas and

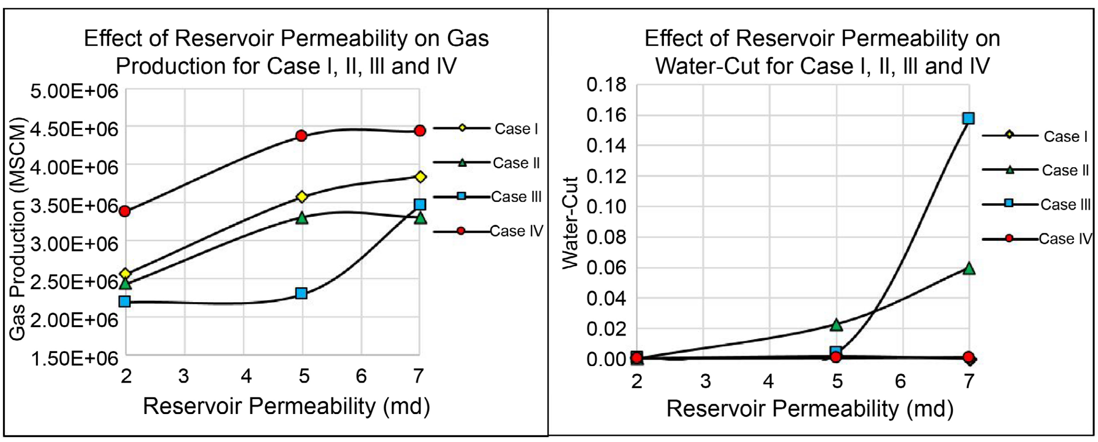

Figure 2. Comparison of cumulative gas production and water cut of Case I, II, III and IV for K_{xy} = 2, 5 and 7 md (S.D = 0.3).

water production. Figure 3 presents the gas saturation profile (cross-section) for Cases II, III, and IV at the same time, revealing that Case IV traps less gas, confirming that CO_2 injection sweeps more gas compared to the other methods.

Figure 4 compares the water saturation profiles for the four cases. In Case IV, the reduced aquifer influx leads to lower water saturation in the reservoir, delaying water breakthrough and thereby increasing gas production. While water breakthrough occurs earlier in Case III than in Case II, gas production is higher due to the reduced contact area between water and gas. However, water production using the conventional method does not significantly mitigate the aquifer influx.

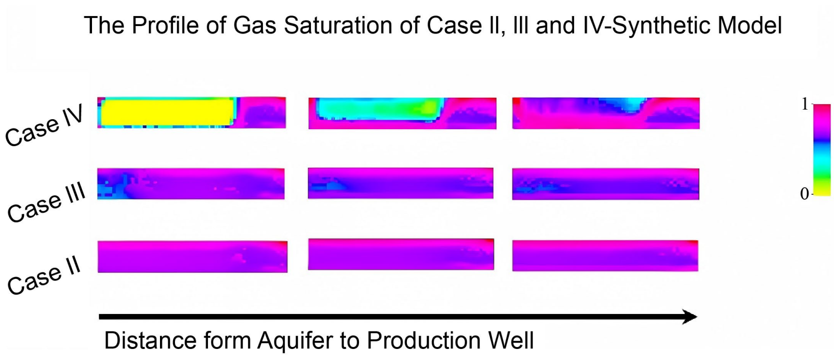

Figure 3. Comparison of gas saturation profile versus distance from aquifer for Case II, III and IV-cross section view.

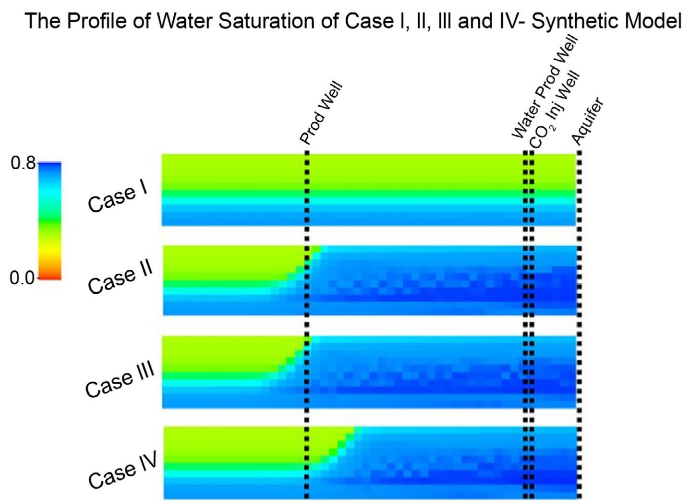

Figure 4. Comparison of water saturation profile for Case II, III and IV.

4.1.2. Effect of Vertical to Horizontal Permeability Ratio (Kz/Kxy)

In addition to reservoir permeability, it is crucial to assess the impact of the vertical-to-horizontal permeability ratio. Figure 5 compares the effects of this ratio on aquifer influx, cumulative gas, CO_2, and water production for Cases II, III, and IV. The figure shows that cumulative gas production for CO_2 injection (Case IV) decreases as the permeability ratio increases, due to the upward movement of CO_2

caused by gravity override. Additionally, the amount of CO_2 produced increases with higher permeability ratios. In contrast, no significant increase in gas production is observed for Cases II and III as the permeability ratio rises, compared to Case IV.

Despite this, CO_2 injection (Case IV) consistently achieves the highest gas recovery, with a 26% increase in gas production even at a ratio of 0.4. However, the efficiency of CO_2 injection diminishes as the permeability ratio increases. Water production in Case III increases significantly as the permeability ratio rises, but this does not improve reservoir performance, even with the high water production levels.

As illustrated in **Figure 5**, the ability of CO_2 injection (Case IV) to significantly reduce aquifer influx is its key advantage. Although aquifer influx in Case III exceeds that in Case II, the amount of water produced in Case III is higher, indicating that less water remains in the reservoir in Case III than in Case II.

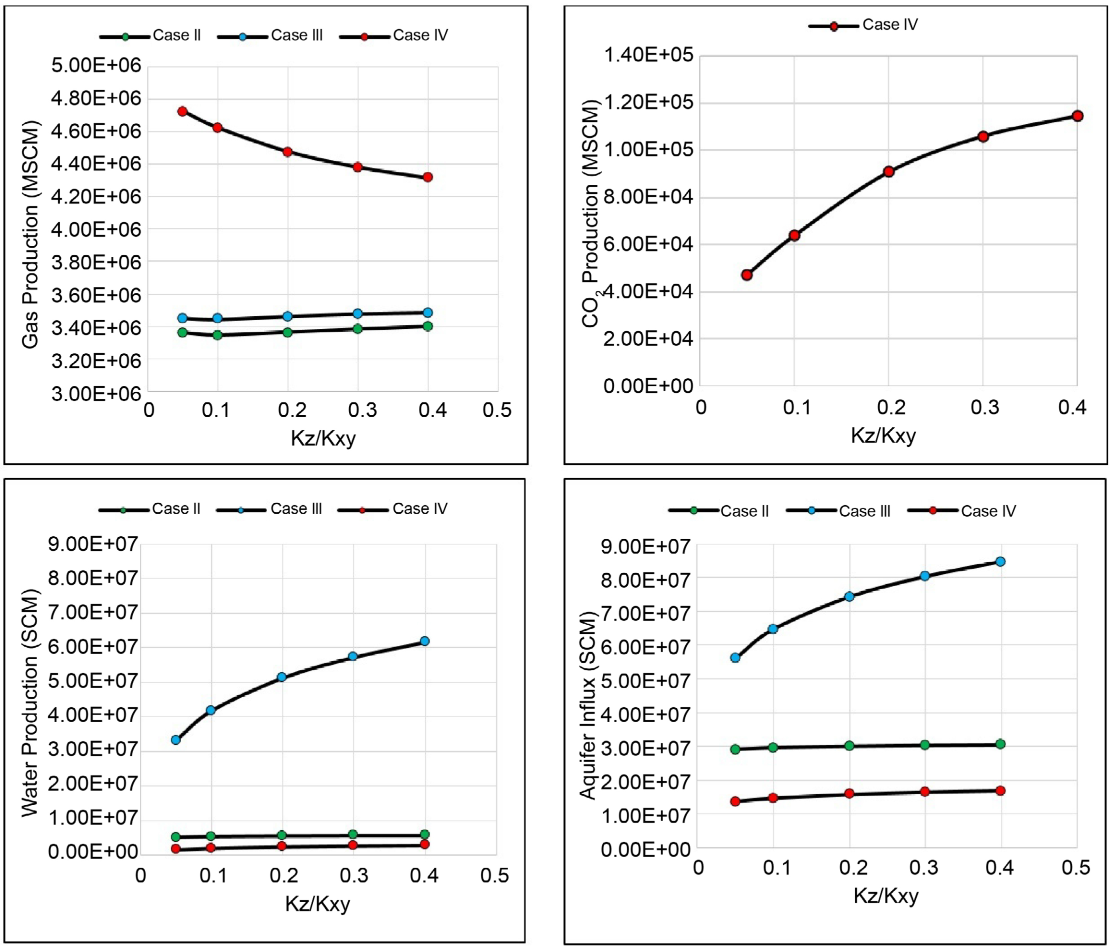

Figure 5. Effect of vertical to horizontal permeability on gas production, CO_2 production, water production and aquifer influx.

4.1.3. Effect of Aquifer Properties

The effect of aquifer properties on both the conventional and proposed methods was examined. Figure 6 and Figure 7 illustrate the impact of aquifer properties (permeability, initial pressure, and radius) on aquifer influx, water, and gas production for Cases III and IV. Figure 6 shows that increasing aquifer permeability results in only a slight reduction in gas production for Case IV, whereas water production increases for Case III, with no corresponding increase in gas production (as seen in Figure 7). Additionally, Figure 6 clearly demonstrates the trend of decreasing efficiency for both cases as aquifer initial pressure rises. Performance decreases in both cases as aquifer strength increases, accompanied by a rise in aquifer influx and water production. However, Case IV consistently achieves

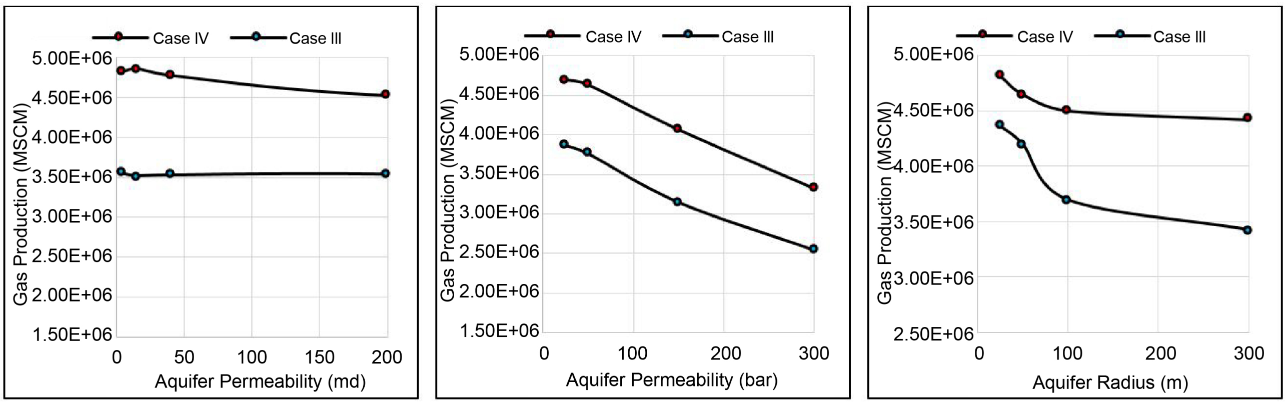

Figure 6. Effect of aquifer properties on gas production for Case III and IV and CO_2 production for Case IV.

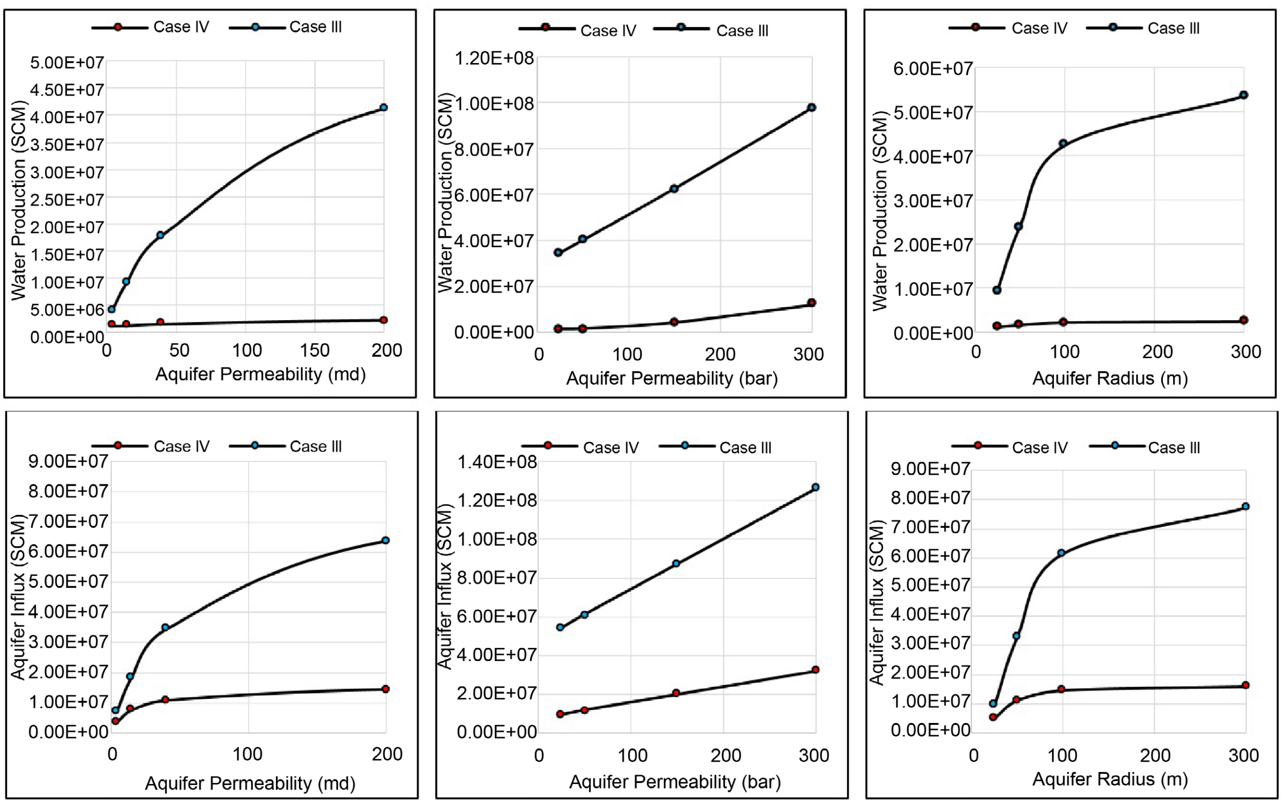

Figure 7. Effect of aquifer properties on water production and aquifer influx for Case III and IV.

higher gas recovery. For both cases, a reduction in aquifer radius leads to increased gas production due to less water encroachment into the reservoir. Overall, no recovery greater than that of Case IV was observed.

4.1.4. Effect of Solubility

The results show that CO_2 dissolution reduces cumulative gas production by approximately 4.2%, confirming that CO_2 dissolution in water decreases sweep efficiency. Water production also dropped by 10%. While aquifer influx was reduced by 39%, slowing water encroachment, the negative effect of dissolution on sweep efficiency ultimately lowered cumulative gas production. Additionally, CO_2 dissolution significantly decreased cumulative CO_2 production by about 70%. Figure 8 illustrates the CO_2 saturation profile with and without the dissolution mechanism, showing that dissolution reduces the vertical movement of CO_2, leading to less CO_2 production. In summary, although CO_2 production was significantly reduced, the overall impact of the dissolution mechanism also led to lower gas production. Figure 8 shows the presence of the CO_2 plume in cross-sectional view.

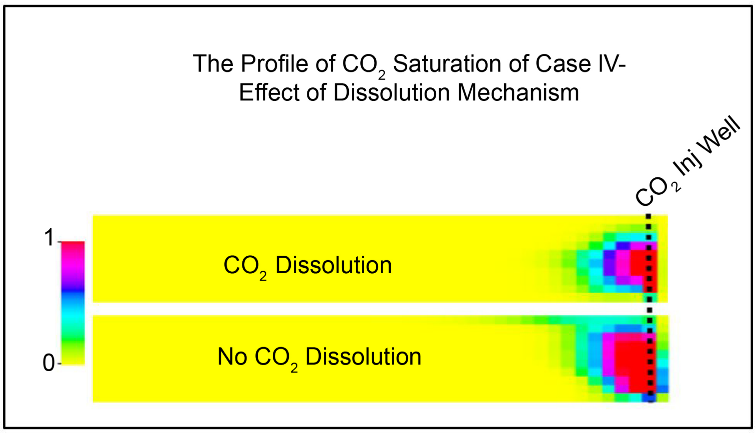

Figure 8. Effect of CO_2 dissolution mechanism on its saturation profile.

4.2. Real Case

This paper addresses two main issues: improving gas recovery from water-drive gas reservoirs while preventing CO_2 emissions and hazardous water production. Initially, the application of CO_2 sequestration was tested on a synthetic heterogeneous water-drive gas reservoir model, and the proposed method was later applied to a real gas reservoir. Previous studies indicated that aquifer activity reduces reservoir performance. Similar to the synthetic model, CO2 injection was carried out while keeping the pressure below 90% of the reservoir's initial pressure. For comparison, the co-production method was also applied, where water was produced from downdip wells and gas from updip wells.

4.2.1. Comparison of Gas Production

Figure 9 depicts the cumulative gas production of three cases (II, III and IV). This figure shows that injecting CO_2 in the reservoir increases cumulative gas production (Case IV) (cumulative gas production of Case III is about 1.14 times of Case II). Hypothetically, for Case III, if sufficient amount of water is produced (lowering reservoir pressure), the reservoir has effectively been converted to a depletion drive but actually, well geometry and water production capabilities are inadequate to completely stop influx of the aquifer.

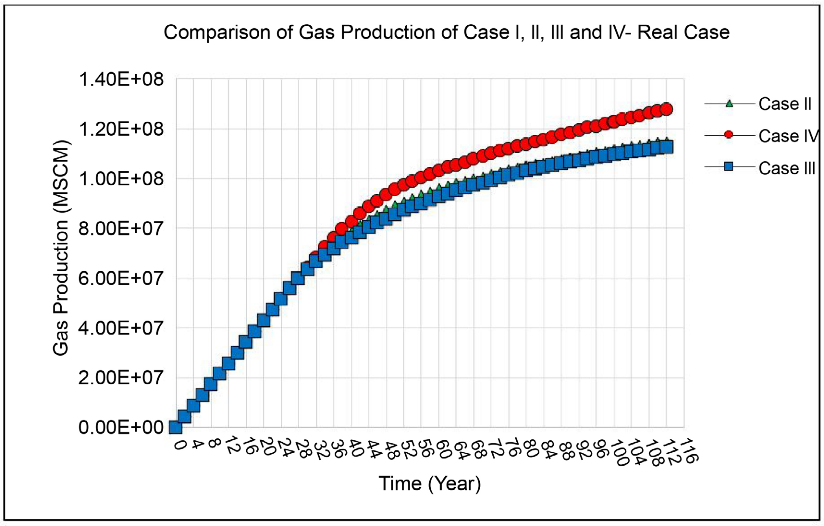

Figure 9. Comparison of gas production of Case I, II, III and lV-real case.

4.2.2. Comparison of CO_2 Production

Figure 10 illustrates the cumulative CO_2 production on the surface for the three cases. The results indicate that CO_2 production remains low until the 112th year. By the end of the process, the cumulative CO_2 production in Case IV is only 2.5 times that of Case II, highlighting that CO_2 production in Case IV is negligible, accounting for approximately 0.006% of the injected CO_2.

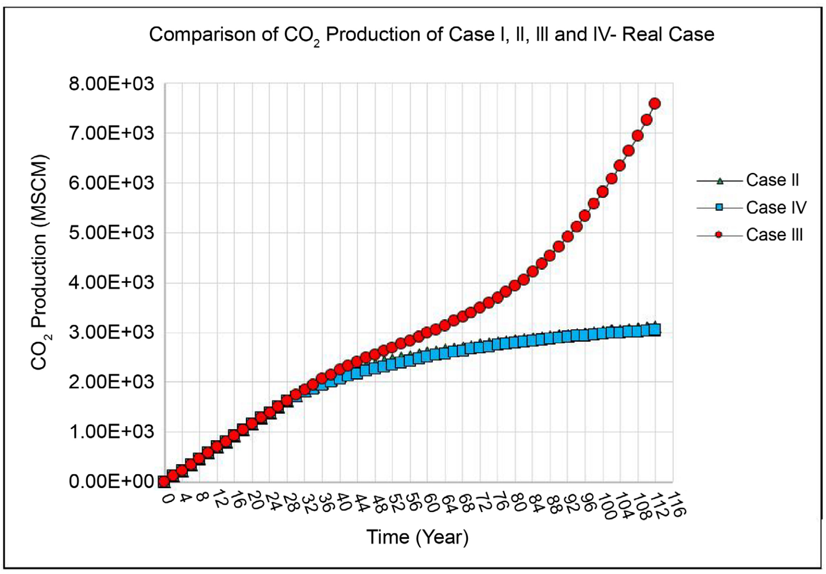

Figure 10. Comparison of CO_2 production of Case I, II, III and lV-real case.

4.2.3. Comparison of Reservoir Pressure

Figure 11 presents the final pressures in the real gas reservoir for Cases I to IV, which are 109, 180, 123, and 307 bar, respectively. Recent investigations indicate that the risk of earth tremors is minimal when gas is stored in depleted gas fields, even at an overpressure of 10% above initial pressure, provided there are no significant changes in reservoir conditions (Damen, Faaij *et al.* 2003). However, in this study, a limitation of 90% of the initial pressure was applied.

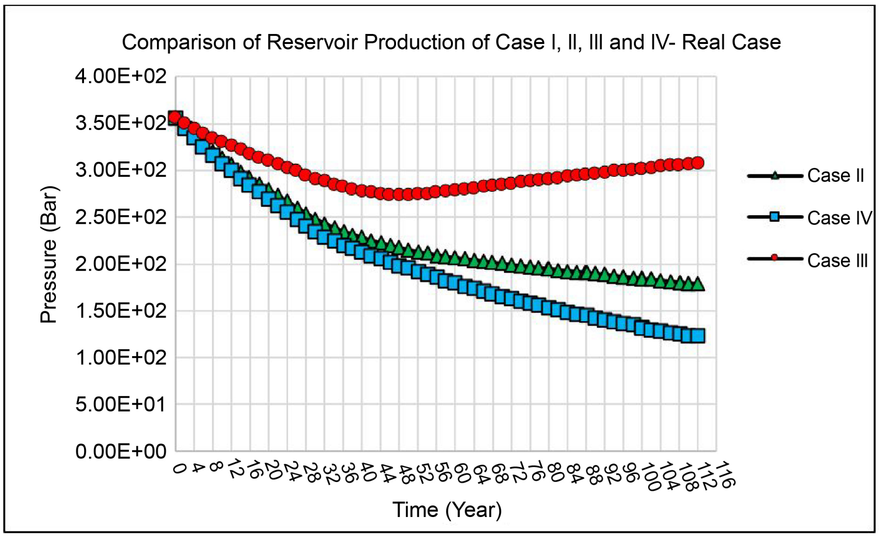

Figure 11. Comparison of reservoir pressure of Case I, II, III and IV-real case.

Effect of Solubility. The dissolution phenomenon influences CO_2 sweep efficiency and aquifer influx, but it has minimal impact on cumulative gas production. Additionally, water production decreased by 9.5%. The results indicate that CO_2 dissolution significantly reduces cumulative CO_2 production by approximately 23%, while the final reservoir pressure decreased by 3%.

5. Conclusions

This study investigated the potential of CO_2 sequestration as a method to mitigate water invasion in water-drive gas reservoirs, utilizing both proposed and conventional methods on synthetic and real case studies. The proposed approach offers several advantages: enhanced gas recovery through CO_2 flooding, the strategic propagation of CO_2 plumes to reduce aquifer influx, and a safe mechanism for CO_2 sequestration that addresses both economic and environmental concerns regarding hazardous water production.

The findings reveal critical insights into the performance dynamics of water-drive gas reservoirs, particularly regarding the influence of reservoir permeability. Notably, as reservoir permeability increases, the performance of the gas reservoir decreases, with the proposed method consistently yielding the highest recovery across all permeability scenarios examined. In low-permeability settings, the conventional method was found to be less effective, despite marginal increases in gas production when compared to base cases. The environmental implications of producing hazardous water are significant, underscoring the need for sustainable production practices.

Key conclusions drawn from this study include:

1. The cumulative gas production for the proposed method declines with increasing permeability ratios due to the upward movement of CO_2 caused by gravity override. However, it still achieves a notable recovery improvement of 26% in the most challenging scenarios.

2. While the proposed method exhibited minimal reductions in gas production with increasing aquifer permeability, the conventional method resulted in heightened water production without corresponding gas recovery. Moreover, higher initial aquifer pressures negatively affected the efficiency of both methods, while a decrease in aquifer radius promoted greater gas production by limiting water encroachment into the reservoir.

3. The results indicate that the dissolution of CO_2 led to a 4.2% decrease in cumulative gas production and a 10% reduction in water production. Although a 39% reduction in aquifer influx effectively curbed water encroachment, the adverse effects of dissolution on sweep efficiency ultimately resulted in reduced cumulative gas production.

4. The application of the proposed method to a real gas reservoir in Northeast Iran demonstrated a significant increase in cumulative gas production, with Case IV showing an improvement of approximately 1.14 times compared to Case II. Importantly, the CO_2 production in Case IV was negligible, accounting for merely 0.006% of the injected CO_2.

In conclusion, this study underscores the viability of CO_2 sequestration as a multifaceted solution for enhancing gas recovery while simultaneously addressing environmental challenges associated with water invasion in gas reservoirs. Local weather conditions—including temperature, humidity, and extreme weather events—can significantly influence the efficiency and safety of CO_2 sequestration technologies, affecting chemical processes, solubility in geological formations, and the long-term stability of storage sites. Therefore, an integrated field modeling approach that considers these factors will be a promising direction for future research, focusing on optimizing CO_2 sequestration methods across various reservoir conditions to maximize their effectiveness and sustainability.

Conflicts of Interest

The authors declare no conflicts of interest regarding the publication of this paper.

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