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Strategic Well Management and Economic Study for Enhanced Recovery and Environmental Sustainability: Evaluating Gas Cycling and CO_2 Injection in a Gas Condensate Reservoir

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Abstract

This comprehensive study investigates the efficacy of gas cycling and CO2 injection techniques in enhancing hydrocarbon recovery from a gas condensate reservoir. Through detailed compositional simulations, the study demonstrates that both techniques significantly increase recovery, with gas cycling achieving an overall recovery of 78.2% in condensate oil and 20% in gas, while CO2 injection achieves 65.3% in condensate oil and 11% in gas for a one year simulation runtime. This enhancement is attributed to gas cycling's ability to maintain reservoir pressure and enhance fluid miscibility, and CO2 injection's effectiveness in reducing oil viscosity and dissolving lighter hydrocarbons. The analysis also delves into well network patterns, identifying slight cost increases but improved recovery with the nine-spot over the five-spot pattern, emphasizing the importance of well spacing and network density. Additionally, it examines the trade-offs involved in adjusting injection parameters, such as pressure and flow rates, to optimize recovery based on specific reservoir characteristics. The study then explores the economic impacts of these methods through the lens of environmental credits associated with CO2 sequestration, revealing that while gas cycling maintains higher conventional economic metrics (NPV and ROI), CO2 injection offers substantial long-term financial benefits, reflecting an increase in cumulative profit (annual) from $0.9 million to $1.1 million due to environmental credits. This positions CO2 injection as a pivotal strategy for aligning economic outputs with global sustainability goals. This study provides a solid foundation for future research aimed at optimizing recovery while adhering to environmental sustainability principles.

Keywords
Gas Condensate Reservoir, CO2 Geo-storage, Multiphase Flow Simulations, Enhanced Oil Recovery, Environmental Sustainability

- This research simulates gas condensate reservoir that enhances hydrocarbon recovery attributed to cyclic gas injection's ability to maintain reservoir pressure and enhance fluid miscibility.
- Simulation results emphasizing the enhancement of hydrocarbon recovery also attributed to the CO_2 injection's effectiveness in reducing oil viscosity and dissolving lighter hydrocarbons.
- The study explores the economic impacts through environmental credits associated with CO_2 geologic storage, revealing that while cyclic gas injection maintains higher conventional economic metrics, CO_2 injection offers substantial long-term financial benefits.

1. Introduction

Gas-condensate reservoirs are those in which the existence of both gas and condensate phases occurs simultaneously. There has been growing interest in studies regarding the pressure-liquid interrelation within gas condensate reservoirs [1-4]. After the pressure has fallen below the dew point pressure at the wellbore, well-defined regions of different liquid saturation set in. Farthest from the production well and situated at pressures exceeding dew point pressure, Region A contains only a single hydrocarbon gas phase. Here, the pressure remains sufficient to prevent condensate dropout, allowing gas to flow freely through the reservoir pores. Moving closer to the wellbore, pressure declines, leading to condensate formation. Region B witnesses a rise in liquid saturation. However, due to the capillary forces, the condensed liquid is trapped within the smaller pore throats and, therefore it is not mobile. This condensate blocking effect practically reduces the relative permeability of gas in this zone, thus reducing the gas flow towards the wellbore. The liquid saturation approaches a critical value, about 25% to 50%, in this near-wellbore region, Region C. Above this threshold, the transition in the liquid phase changes from immobile to mobile. In this region, the produced fluid becomes a two-phase mixture with constant composition that flows towards the wellbore [5-8]. While production can be associated with high gas velocity that could mobilize the condensate, there is a competing phenomenon called velocity stripping. During velocity stripping that occurs in Region D, the high-velocity gas stream may strip lighter hydrocarbon components from the liquid, significantly changing the composition of the produced fluid [9, 10]. Therefore, knowing these regional variations in liquid saturation is very important in optimizing well management strategies in gas condensate reservoirs. Proper pressure drawdown and production rate management were suggested based on studies to reduce the formation of condensate blockage in Region B and to enhance recovery of condensate from Region C-plus-D [11-15] as shown in Figure 1.

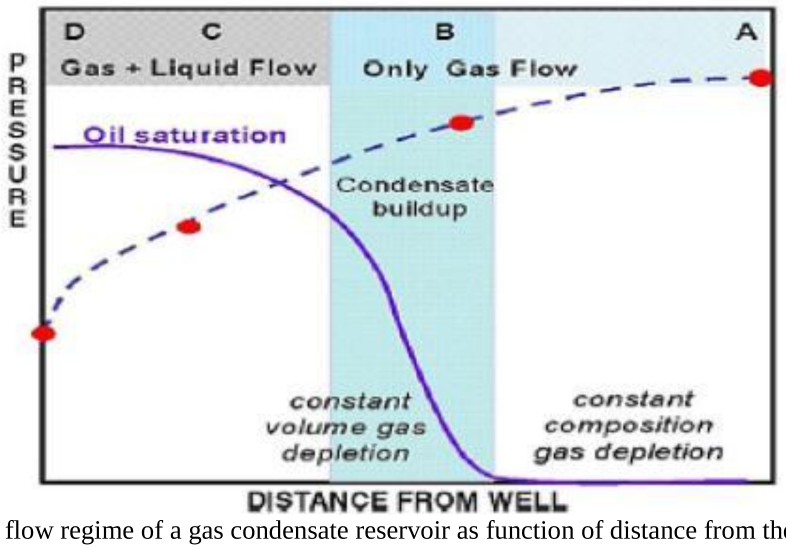


Fig. 1 Pressure flow regime of a gas condensate reservoir as function of distance from the wellbore [15]

Recovery mechanisms from gas condensate reservoirs are influenced majorly by condensate banking, which may further lead to a time-dependent reduction in permeability and recovery rates [16, 17]. Reservoir pressures and temperatures must, therefore, be managed in such a manner as to avoid condensate drop-out and to ensure the continuity of gas production rates. Effective well management is key to enhanced recovery from a gas condensate reservoir. It focuses on proper well spacing, completion techniques, and production optimization strategies to reduce condensate banking and increase recovery efficiency [18, 19]. Gas injection has become one of the most potent EOR processes [20-23]. In this process, gas is injected, which is either miscible or immiscible with the reservoir oil, to improve the mobility of oil and sweep efficiency. Several beneficial effects are created by the injected gas:

Increased Mobility Ratio: Gas, being less viscous than oil, significantly improves the mobility ratio within the reservoir. This allows for easier displacement of oil towards production wells [24, 25].

Enhanced Oil Relative Permeability: Gas injection have altered the rock properties at the time, giving an increase in the relative permeability to oil. Essentially, what this means is that oil flows readily through the rock pores in the presence of injected gas [26, 27].

Reservoir Pressure Maintenance and Sustained Drawdown: Gas injection helps in maintaining the pressure within the reservoir, thereby enabling the continuous production of oil at higher rates for a longer time. How efficient such pressure maintenance will be depends on the type of injection and how reservoir characteristics are compatible with each other [28, 29].

Another common source used for gas injection is production gas; however, this is applied only after the removal of impurities through processing. This approach offers a cost-effective solution while maximizing utilization of available resources [30, 31]. Gas cycling is effective method for managing gas condensate reservoirs, it has been the focus of a number of research studies. Extensive simulation and experimental studies, until now, has shown this method to be very promising for delaying condensate banking and significantly enhancing ultimate hydrocarbon recovery [32 – 34]. The principle underlying gas cycling is based on the injection of dry gas produced during the process of depletion, back into the reservoir at periodic intervals. This strategic approach ensures that the pressure will always remain above the dew point pressure; gas cycling avoids condensate droplet formation within the reservoir. The condensate will therefore be highly mobile and thus able to flow more easily toward production wells [35]. This technique acts, much like a pressure maintenance scheme, to displace pockets of residual oil and create a more even distribution of pressure throughout the reservoir. This tends the sweep efficiency to be increased so more of the reservoir as it comes contacted with the flowing fluids, enabling greater recovery. The effectiveness of the gas cycling operation has been confirmed through numerous studies [36 – 38]. For instance, in one case study, gas cycling at different stages of depletion and injection well patterns in a particular gas condensate reservoir showed a remarkable improvement in gas and condensate recovery, compared to when primary depletion techniques alone were relied upon [39]. Gas Cycling reduces the overall energy consumed with associated GHG emissions by reducing the requirement for external gas compression [40].

In a gas condensate reservoir, CO_2 injection offers twin advantages of improved recovery and climate change mitigation through environmental sustainability. Using CO_2 as a displacing fluid can increase the recovery factors while storing greenhouse gases beneath the ground [41, 42]. While acting as an EOR agent, CO_2 reduces the minimum miscibility pressure of the reservoir that can miscible-contact the original reservoir gas to mobilize the condensate droplets [43]. This technique also contributes to carbon capture and storage, as captured CO_2 is stored in the reservoir formation. The research investigates the various impacts of injection pressure of CO_2 on condensate recovery efficiency and storage efficiency. Such studies point out the fact that by the optimization of the injection pressure, hydrocarbon recovery can be maximized along with effective CO_2 geologic storage, hence achieving enhanced recovery and environmental benefit [44– 46].

Gas cycling and CO_2 injection have major environmental and economic benefits over conventional depletion methods. The initial project cost may well be high with gas cycling and CO_2 injection, but the time economics could address initial hurdles. Higher ultimate recovery of hydrocarbons, especially in condensates, is obtained with higher total production rates [47, 48]. In addition, the decreased GHG emissions and potential carbon credits due to CO_2 sequestration have inherent environmental worth and thus are liable to render these technologies even more economically viable [49, 50]. Gas-injection patterns usually lead to much higher ultimate hydrocarbon recoveries and, respectively, higher NPVs—all-inclusive economic indicators to evaluate project profitability [51–54]. NPV takes into account the up-front investment and future cash flows a discounted project will generate. Gas-injection techniques can significantly enhance the economic viability of the project through the maximization of production and minimization of environmental liabilities.

In this context, this is a compositional reservoir modeling study conducted in efforts to evaluate the gas cycling and CO_2 injection for enhanced recovery and environmental sustainability in the gas condensate reservoir. The representative case study is a single heterogeneous layer of the gas condensate reservoir with complex features and fluid compositions. The model compositional behavior is carried out by a compositional simulator available for education purpose. The simulator has been shown in previous studies to provide extensive validation of compositional modeling accuracy [55 – 58], allowing this current choice of modeling approach to be made with confidence. This study considered sensitivity analysis of the production development strategy with gas cycling and CO_2 injection. Primary attention is given to the identification of well management strategies that would maximize ultimate recovery and reduce condensate loss within the reservoir. Different parameters, including well network and density patterns, are analyzed in this regard for understanding their respective influence on both the optimization of the production process and economic viability. The results from this sensitivity analysis are presented hereinafter and reported in this manuscript.

2. Methodology

2.1 Reservoir Model and Fluid Properties

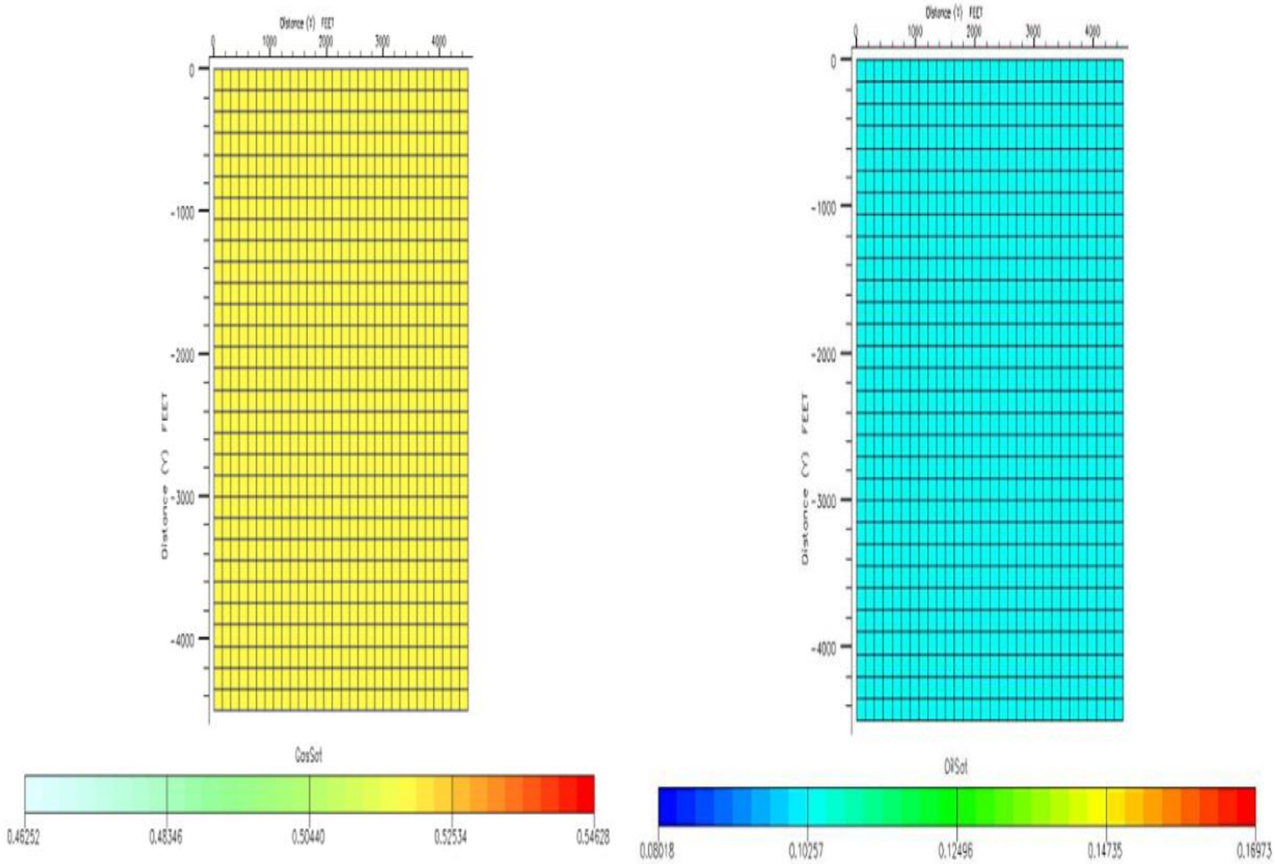
In this research work, a single-layer heterogeneous gas condensate reservoir is modelled using a compositional reservoir simulator. A 30 × 30 × 1 Cartesian grid system is used, representing the physical dimensions of 150ft × 150ft × 1ft.

2.1.1 Reservoir Characteristics

Permeability: Horizontal permeability ranged from 430 to 1400 mD, with vertical permeability set at 100 mD.
Porosity: The reservoir porosity was 13%.
Fluid Contacts: Gas-water contact was established at a depth of 7500 ft.
Initial Saturations: Initial water and gas saturation were 22% and 65%, respectively.
Pressure and Compressibility: Initial reservoir pressure was set at 3550 psi. Rock and water compressibility values were 3×10^{-6} psi^$^{-1}$ and 4×10^{-6} psi^{-1}, respectively.
Condensate-Gas Ratio: At initial reservoir pressure (3550 psia), the condensate-gas ratio was zero.

Table 1 Compositional and Critical Pressure-Volume-Temperature (PVT) Properties of Gas Condensate Fluid [55, 56, 59]

Reservoir Temperature				Pressure (Saturation)			
200^{0}F				3540psia			
Components	**Molecular Weight**	**Mole percent**	**Pressure (critical)**	**Temperature (Critical)**	**Acentric factor**	**Compressibility (critical)**	**Parachor**
C1	16.04	75	667.78psi	343.07^{0}F	130	28.4 psi^{-1}	0.77
C3	44	17	618.7psi	665.64^{0}F	15.2	27.7 psi^{-1}	0.015
C10	134	04	351psi	1126.78^{0}F	38.5	24.8 psi^{-1}	0.0404
C15	206	02	252.26psi	1303.12^{0}F	55	22.7 psi^{-1}	0.055
N2	28.01	01	492.31psi	227.16^{0}F	400	29.1 psi^{-1}	0.41
CO2	44.01	01	1071.33psi	548.46^{0}F	22.5	27.4 psi^{-1}	0.78



(a) Initial gas saturation profile (b) Initial oil saturation profile
Fig. 2 Initial Fluid Saturation Profiles of a Heterogeneous Gas Condensate Reservoir

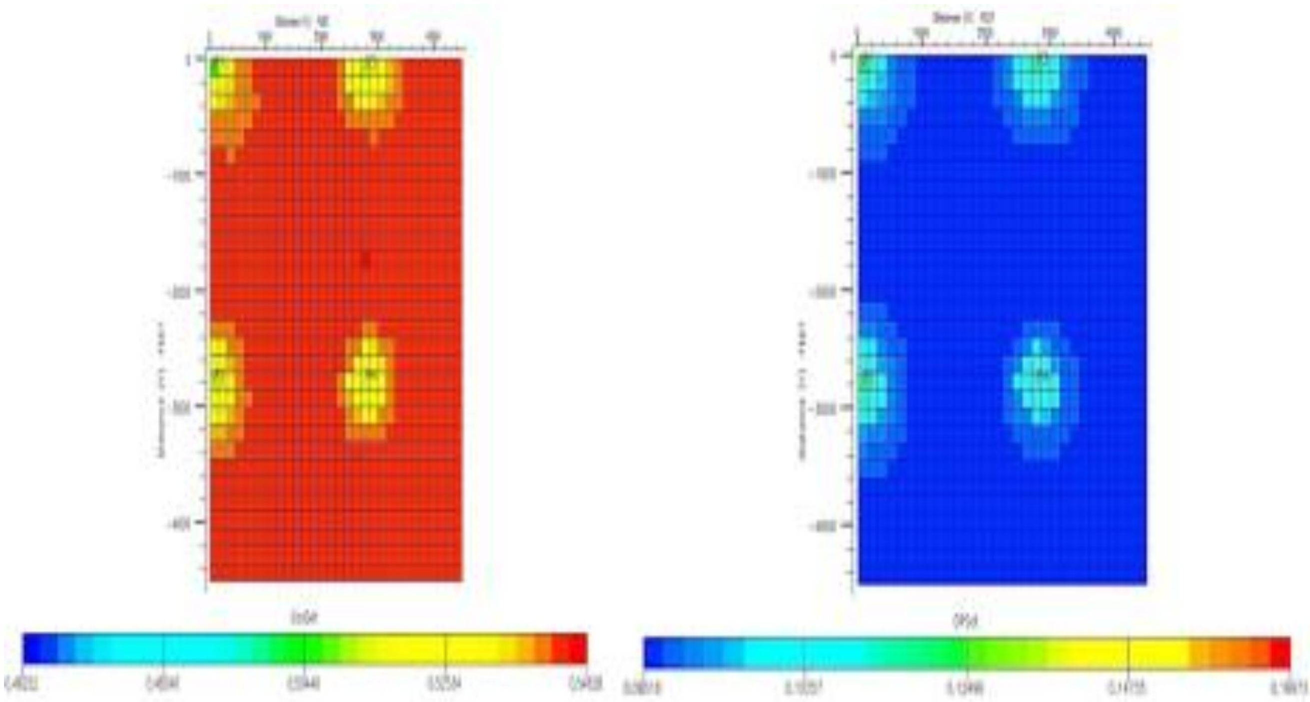
2.1.2 Fluid Properties

Similar to the reservoir rock properties, the fluid properties were derived from Kenyon's model used in the third SPE comparative study [55] and scaled-up for this specific reservoir. The fluid model was then validated against available experimental data from the literature [5, 7, 56, 59]. The key fluid properties, including composition and critical properties, are summarized in Table 1.

2.1.3 Equation of State

The Peng-Robinson Equation of State (EoS) was chosen to model the fluid behavior. This selection aligns with established practices in similar studies provided.

Figure 2 depicts the initial distribution of gas and oil saturation within a gas condensate reservoir. To understand the complex interactions at play, a one-year simulation is conducted assuming natural depletion (pressure decline) of the reservoir. Figure 3 presents the simulated saturation profiles depicting percentage of pore space occupied by a fluid after one year of production.



(a) Residual gas distribution profile (b) Residual oil distribution profile

Fig. 3 Residual Fluid Saturation Profiles after One Year Natural Depletion

Figure 3(a) reveals a significant reduction in gas saturation near the wellbores, dropping to around 50% compared to an average of 54% across the entire reservoir. This suggests that gas flow is hindered near the well due to a phenomenon called condensate banking. Figure 3(b) highlights the impact of condensate loss on oil saturation. The oil saturation is lower near the wellbores that is around 8% compared to the rest of the reservoir that is around 11%. This indicates that condensate dropout affects oil flow as well.

Since the reservoir relies on natural pressure to drive production, managing reservoir pressure is crucial to minimize condensate banking and maintain gas production rates. Permeability damage caused by condensate banking is a significant concern. Effective production strategies are essential for maximizing recovery from a gas condensate reservoir. This study emphasizes the importance of such production development strategies for optimal well performance.

2.2 Production Development Strategy

The production development strategy explored two Enhanced Oil Recovery (EOR) methods: gas cycling and CO_2 injection. Both injection methods are conducted at a pressure of 4000 psi, exceeding the reservoir's dew point pressure of 3540 psi.

Gas Cycling: Produced gas, stripped of condensate through a two-stage separation and stock tank process, reinjected continuously back into the reservoir. This re-injected gas is simulated maintain the same composition as the initial reservoir gas.

CO_2 Injection: Pure CO_2 (100% molar composition) is injected and simulated.

2.2.1 Well Management Scheme

The well management plan involves four production wells positioned around a single injection well. All wells are controlled by bottom-hole pressure (BHP) with a target pressure of 1000 psi. This initial study focused on comparing the impact of gas cycling versus CO_2 injection on reservoir productivity over a simulated period of one year.

Then the study performed for two well network density models: nine spot and five spot patterns. Both models utilized seven and four production wells respectively, each producing at a constant rate of 0.4 MMScfD and 0.7 MMScfD respectively with a minimum bottom-hole pressure (BHP) of 500 psi. Surrounding one injection well in each model injecting cyclic gas at a combined rate matching total field production of 2.8 MMScfD and maintaining an injection BHP of 4,000 psi. Simulations for this study conducted for 19 years. The results with the condensate recoveries presented and discussed.

To identify the performance on injection rates and pressures for maximizing condensate recovery, a study was conducted using a nine-spot well pattern. The study involved seven vertical production wells and two vertical injection wells. Several scenarios are simulated for injection during a 15-year period of production. The ranges used for injection rates varied from 1.05 to 1.4 MMScfD, while injection pressures ranged from 2,500 to 4,500 psi.

2.2.2 Economic Study

The management of such wells and its economics analyzed through a quantitative technique that is based on Net Present Value. NPV takes into account the income and even expenses of the project for the whole lifespan, which are then discounted present value. This research is assisting to analyze different well management options in a transparent way and clearly indicate the best whole project profitability or feasible plan. In this study, NPV refers to the Net Present Value, which reflects all cash flows of the project over the whole period of *n* years of the analysis. Even though for every year, denoted by *n*, the cash flow, *CF*, will differ, it is discounted at a yearly discount rate, *r*, which reflects the time value of money. The different NPV computations are assessed with the mathematical expression:

$$NPV = \sum_{n=1}^{N} \frac{CF_n}{(1+r)^n} - C_{cap} \qquad \text{Equation 1}$$

$$CF_n = R_n - E_n \qquad \text{Equation 1(a)}$$

$$R_n = P_n^o Q_n^o + P_n^g Q_n^g \qquad \text{Equation 1(b)}$$

$$E_n = C_n^{g,inj} Q_n^{g,inj} + C_n^w Q_n^w \qquad \text{Equation 1(c)}$$

The NPV calculation considers the following factors:
Capital expenditure (Ccap): The capital cost of setting up the project (including drilling and equipment);
Annual revenue (Rn): The total income generated from oil, gas and water production in each year *n*;
Annual operating expenditure (En): The ongoing costs associated with production operations in each year *n*;
$Q^o n$: Daily oil production rate in year *n*;
$Q^g n$: Daily gas production rate in year *n*;
$Q^w n$: Daily water production rate in year *n*;
$Q^{g,inj} n$: Daily gas injection rate in year *n*.

Table 2 summarizes more detailed breakdown of other parameters used in this study

Specific Values used in NPV Calculations [59] Parameter	Value	Parameter	Value
Condensate/oil sale price (P^o)	$105/bbl	Gas cycling/injection cost ($C^{g1,inj}$)	$6/MScf
Gas sale price (P^g)	$6/MScf	CO2 injection cost ($C^{g2,inj}$)-Optional	$0.29/MMScf
Capital expenditure (Ccap)	$500000	Water disposal cost (C^w)	$0.5/bbl

To further assess the effectiveness of the well management strategies with clarity, profit margin, return on investment (ROI) and cumulative profit is considered essential for a particular project [60]. These factors are evaluated in this study with following mathematical expressions:

$$Profit\ Margin\ (\%) = 100 * (Rn - En)/Rn \qquad (2)$$

$$ROI\ (\%) = (Net\ Profit\ /\ Ccap) * 100 \qquad (3)$$

$$Cumulative\ Profit = \sum_{n=1}^{t} (Rn - En - Ccap) \qquad (4)$$

To achieve environmental sustainability, it is crucial to adopt mitigation strategies that balance long-term ecological health with economic viability. Upright underground storage is one of the most vital steps involved in the process. It captures and stores CO_2 in geological formations through injections, hugely reducing greenhouse gases in the atmosphere, which would help stabilize the climate. Besides, CO_2 sequestration creates huge environmental credits and provides a financial incentive to industries to invest in carbon capture technologies. Such incentives make it economically viable for industries to adopt practices that are in sync with sustainable development goals, harmonizing industrial operations effectively with environmental stewardship [61, 62]. The formula followed in this study to calculate environmental credits is based on the amount of CO_2 sequestered in tons and the market price considered in this study is $50/ton for carbon credits [63]:

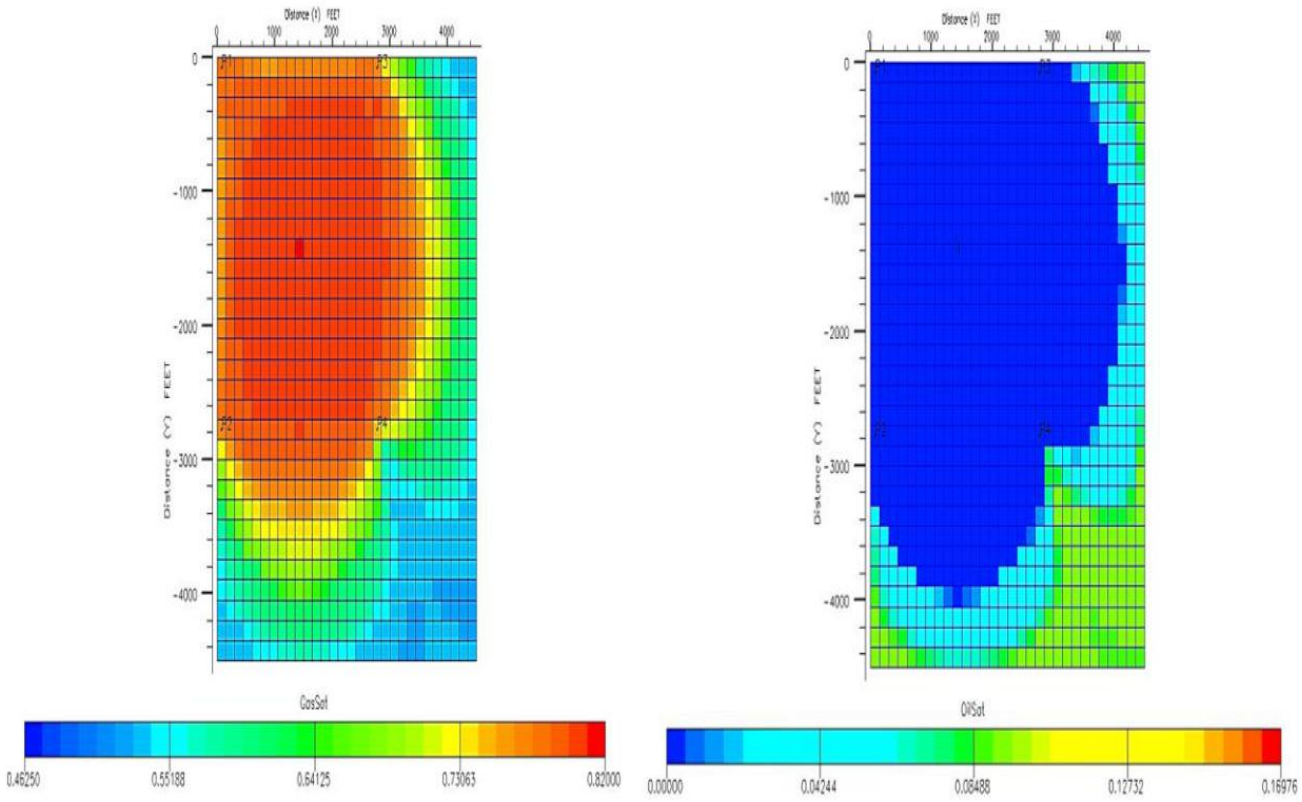
$$Environmental\ Credits = CO2\ sequestered * Carbon\ credit\ price \qquad (5)$$

This paper emphasizes the importance of sufficient characterization of the reservoir and its simulation for the identification of various production issues such as condensate banking. Moreover, efficient condensate recovery is simulated and explained by incorporating some effective well management schemes including injection of cycling gas or CO2 injection in the section of well management scheme. The economic evaluation using NPV, profit margin, ROI and cumulative profit then performed which provide guidance for the most favorable approach for long-term reservoir production and environmental sustainability.

3. Well Management Schemes – Results and Discussion

3.1 Study on Gas Cycling and CO2 Injection

Gas cycling and CO2 injection applied annually are two methods employed to enhance recovery of hydrocarbons (annual) from a gas condensate reservoir. Each method offers distinct benefits based on its interaction with the reservoir fluids. Study of gas cycling and CO2 injection emphasizing for improving the condensate recovery is presented in Figure 4 and Figure 5 respectively. The data and simulation results originate from a compositional reservoir simulator.



(a) Residual gas distribution profile (b) Residual oil distribution profile

Fig. 4 Residual Fluid Saturation Profiles after One Year of Gas Cycling

Both gas cycling and CO2 injection demonstrated improvement in condensate recovery compared to natural depletion. A definitive conclusion on their relative effectiveness is not yet possible at this early stage of the simulated production of one year. As Figure 4(b) and Figure 5(b) suggest, neither injection method fully reached higher permeability zones within this timeframe, potentially leaving behind recoverable hydrocarbons. This highlights the need for further investigation with extended simulation periods.

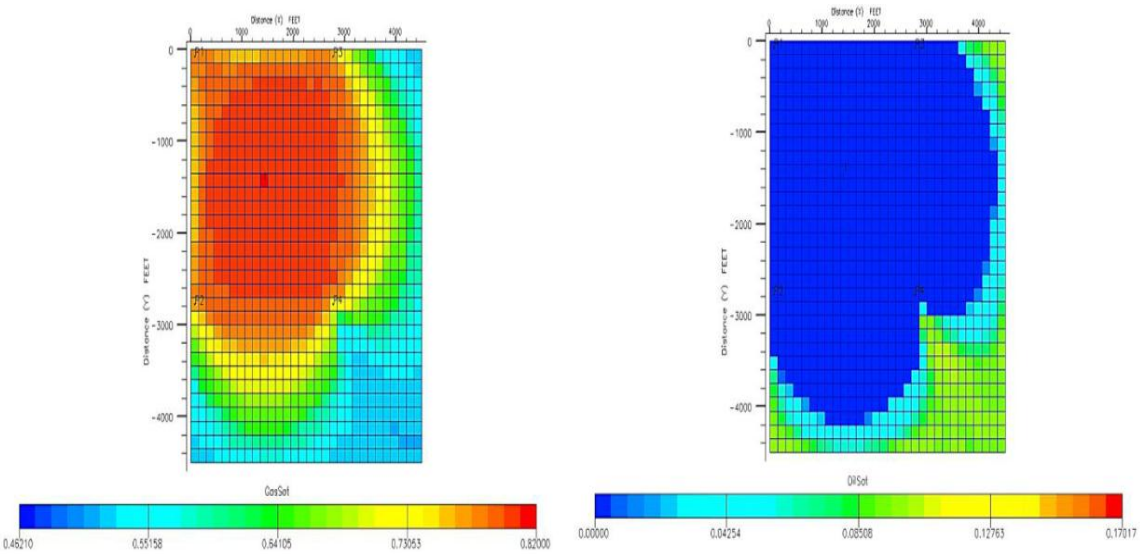
However, numerical simulation results comprehend detailed findings that are summarized in Table 3 and conclusive replication presented in Figure 5.

The initial study provides valuable insights captured in the detailed findings of Table 4 and the supportive visualization presented in Figure 5. Study emphasized that for maximizing overall well production, both condensate and gas recovery shall be considered for evaluation of gas cycling and CO2 injection.

Table 3 Summary of one-year simulation

Injection Scheme	**Condensate-Gas Ratio** (MMStb/BScf)	**Field oil production total** (MMStb)	**Oil Recovery (%)**	**Gas Recovery (%)**
Gas cycling	0.415	1.33	78.2	20
CO2 injection	0.616	1.11	65.3	11

Gas cycling reinjects produced gas back into the formation. Injecting gas at pressures exceeding the dew point vaporize some oil components, potentially increasing their recoverability. Additionally, gas cycling promote improved mixing (miscibility) between the injected gas and the reservoir oil, potentially leading to a more efficient displacement of the oil front. Notably, gas cycling has been shown to achieve condensate-gas ratio (CGR) of 0.415 MMStb/BScf and a gas recovery of 20%. Oil recovery through gas cycling in this specific case reached 78.2%.



(a) Residual gas distribution profile (b) Residual oil distribution profile

Fig. 5 Residual Fluid Saturation Profiles after One Year of CO2 Injection

CO2 injection relies on the interaction between injected CO2 and the reservoir oil. This interaction cause swelling of the oil phase and a reduction in its viscosity, both of which may improve oil mobility and recovery. Additionally, CO2 dissolve some lighter hydrocarbon components, further enhancing their recoverability. CO2 injection has achieved a CGR of 0.616 MMStb/Bscf and a gas recovery of 11%. Oil recovery through CO2 injection in this specific case reached 65.3%. Both gas cycling and CO2 injection demonstrate significant potential for improving condensate recovery (Figure 6). It's important to note that the effectiveness of each method can vary depending on specific reservoir characteristics. Evaluating these characteristics is crucial for selecting the most suitable recovery method for a particular reservoir. In this study, gas cycling achieved a higher overall recovery (oil and gas) compared to CO2 injection. However, further analysis considering reservoir properties, operational parameters and other miscellaneous factors are necessary to be considered to determine the generally effective method.

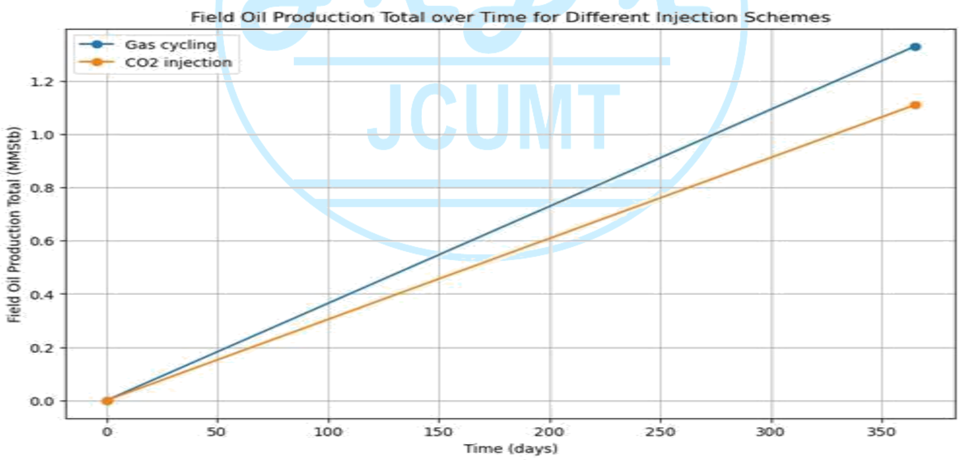


Fig. 6 Oil Production with Gas Cycling and CO2 Injection over Time

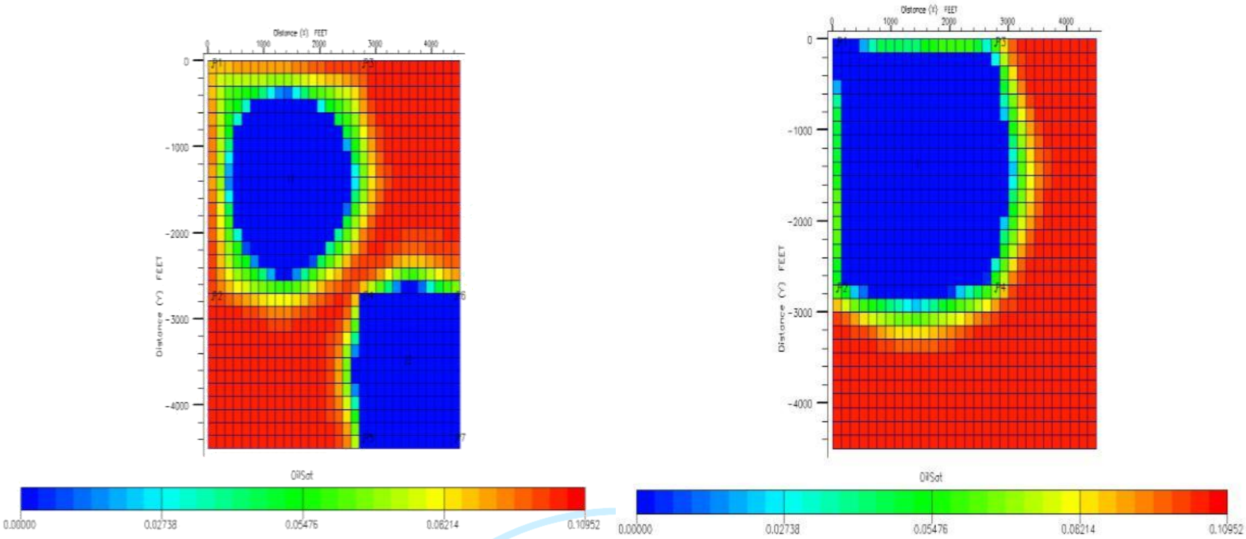
3.2 Gas Cycling Study on Well Network of Nine Spot and Five Spot

In the quest to maximize hydrocarbon recovery from a gas condensate reservoir, two key well network methods are employed for 19 years production scheme. Each well network method interacts uniquely with reservoir fluids, leading to distinct benefits. This study delves into nine spot and five spot gas cycling, with a particular focus on their effectiveness in enhancing condensate recovery, as presented and illustrated in Figure 7. Table 4 also summarizes the key findings.

Table 4 Drilling Cost and Performance Outcomes of Nine Spot and Five Spot Well Network

Well network Pattern	Gas injection volume (BScf)	Drilling reference costs ($M)	Oil recovery (%)
Nine spot well network	194	149.23	42
Five spot well network	194	139.62	41

Table 4 indicates a slight increase in project development costs associated with the nine-spot pattern compared to the five-spot pattern. Despite this, both well network pattern's potential for improved condensate recovery was evaluated and presented in Figure 7. Simulations showed a 1% improvement in condensate yield with the nine-spot pattern. The analysis on both well network patterns revealed a key factor, that is well spacing. Denser well networks achieved with closer well spacing in case of nine-spot pattern, tend to improve areal sweep efficiency. This efficiency refers to how effectively the injected cyclic gas displaces the existing gas and mobilizes the trapped condensate (previously lost). However, denser well networks also come with a drawback of increased drilling costs during project development. Despite the cost increase, improved areal sweep efficiency has a significant impact on condensate recovery. By reducing the residual condensate saturation within the reservoir, gas cycling becomes effective to mobilize the trapped condensate leading to its improved recovery.



(a) Residual Oil Saturation in Nine Spot Pattern (b) Residual Oil Saturation in Five Spot Pattern

Fig. 7 Simulation results on One Year Gas Cycling Impact on Condensate Recovery

3.3 Nine Spot Pattern Study on Injection Pressure and Injection Flowrate

To maximize the amount of hydrocarbons recovered from a gas condensate reservoir over a 15-years production period, this study investigates the impact of two key well injection parameters: injection pressure and injection flowrate.

Table 5 Impact of Gas Injection Pressure on Production (Nine-Spot Pattern)

ID No.	Injection Pressure Value (psi)	Field Gas Injection (Total - BScf)	Oil Recovery Factor (%)	Gas Recovery Factor (%)
25	3500	9.4	36.63	45.33
24	4500	11.5	23.68	52.57
23	4000	11.49	23.76	52.51
22	2500	9.14	38.22	39.84
21	3500	10.58	29.36	45.63
19	2500	9.15	38.18	41.49
18	4000	10.58	29.34	48.66
16	3500	9.37	36.82	40.81
12	2500	8.82	40.24	39.11
03	2500	9.35	36.8	44.8
01	3000	9.37	36.76	44.95

A nine-spot gas cycling model is applied to a simulated heterogeneous gas condensate reservoir to optimize production. The study focuses on finding the ideal injection pressure and injection flow rate. The results of the simulation are then analyzed to assess how these factors can improve the well's productivity.

Table 5 shows a selection of simulation results from a sensitivity analysis based on different injection pressures and their potential values of gas injection total. This analysis examined 25 different job IDs to identify the injection pressure for different values of gas injection (total) that leads to the highest hydrocarbon production; best 11 results out of 25 job IDs are presented following.

The analysis of injection pressure in a gas condensate reservoir reveals a trade-off between maximizing oil recovery and maximizing gas recovery. While lower pressure (2500 psi) leads to a higher oil recovery factor (40.24%), indicating efficient oil displacement, a higher pressure (4500 psi) maximizes gas recovery (52.57%). However, the optimal pressure isn't simply about maximizing one resource.

Higher pressure often requires injecting more gas, which impacts both recovery and costs. The analysis, although not explicitly focused on total gas injected, implicitly acknowledges this link. The economic evaluation should consider both the volume of gas recovered and the total gas injected and its associated cost when evaluating different pressure scenarios.

Table 6 presents a selection of results from a sensitivity analysis that investigated the effect of different injection flow rates on total gas injection and, consequently, on maximizing hydrocarbon production. The analysis examined nine different job IDs. The table highlights the four most favorable scenarios out of the nine that identify the injection flow rate for various total gas injection values that lead to the highest hydrocarbon production.

Table 6 Impact of Gas Injection Rate on Production (Nine-Spot Pattern)

ID No.	Injection Flowrate Value (MMScfD)	Field Gas Injection (Total – lb-mole)	Oil Recovery (%)	Gas Recovery (%)
09	2.4	30,397	56.2	13.53
07	2.1	26,803	52.5	23.68
03	2.1	28,842	55.4	14.9
01	2.8	31,410	58	9.9

This analysis examined the impact of injection flow rate on oil and gas recovery in a gas condensate reservoir. The highest oil recovery (58.0%) is achieved with an injection flow rate of 2.8 MMScfD (ID No. 01). However, this comes at the expense of a lower gas recovery factor (9.9%). A flow rate of 2.1 MMScfD (ID No. 03 & 07) offers a good compromise, achieving significant oil recovery (52.5% & 55.4%) with a moderate increase in gas recovery (14.9% & 23.68%) compared to the oil-prioritized scenario.

The optimal injection flow rate depends on the project's priorities. If maximizing oil recovery is crucial, 2.8 MMScfD (ID No. 01) might be preferable. However, for projects prioritizing gas recovery, a flow rate of 2.1 MMScfD (ID No. 03 or 07) could be more suitable. The final decision should consider factors including injection costs and long-term reservoir performance. A comprehensive evaluation that incorporates these factors will help determine the most profitable injection flow rate for the project.

4. Economic Study – Results and Discussion

4.1 Gas Cycling and CO2 Injection for Enhanced Recovery

This section focuses on the economic benefits of using gas cycling and CO2 injection for pressure maintenance; these injection techniques according to well management scheme are previously studied and presented in section 3.1 Study on Gas Cycling and CO2 injection. In this section the economic analysis on different gas injections to determine the most profitable strategy is presented. The Net Present Value (NPV) equation explained earlier in the Methodology section is used to evaluate the yearly profit for each gas injection scheme. As discussed in methodology and section 3.1 Study on Gas Cycling and CO2 injection, this study with initial pressure of 3550psi has simulated one-year production of injections for both gas cycling and CO2 injection. At initial pressure at the time of discovery, the reservoir existing in a single gaseous phase with gas in-place of 16BScf. Table 7 shows the estimated annual production values obtained from the simulations. The analysis suggests that gas cycling lead to higher annual oil and gas production compared to CO2 injection. However, economic analysis using this data is also analyzed and presented further. Table 2 already provides the cost data that is taken in this study for the NPV calculations. The results are summarized in Based on the economic evaluation presented in Table 8, NPV of gas cycling yield a net present value of $231.36 billion, is the most favorable strategy for pressure maintenance compared to CO2 injection, which has an NPV of $181.39 billion (Figure 8). In terms of profit margin over time, gas cycling, with an annual percentage value of 71.3, is again the most favorable strategy compared to CO2 injection, which has a percentage value of 66.8 (Figure 9). However, this evaluation suggests that CO2 injection could be considered, as it yields a productive profit margin over time. The decision-making process would benefit from a comprehensive economic evaluation. Table 8 and comprehensively presented in Figure 8.

Table 7 Estimated Annual Production Output

Injection Type	Oil FVF (bbl/Stb)	Oil In-place (N–MMStb)	Gas Solubility (Rs-MScf/Stb)	Gas FVF (cf/Scf)	Gas In-Place (G –BScf)	Oil Production (Q^o –MMStb)	Gas Production (Q^g –BScf)	Gas Injection ($Q_{g,inj}$ BScf)
Gas cycling	1.46	0.368	2.099	0.72	11.33	1.33	676.0	675.0
CO2 injection	1.46	0.315	2.099	0.72	14.8	1.11	530.0	528.0

Based on the economic evaluation presented in Table 8, NPV of gas cycling yield a net present value of $231.36 billion, is the most favorable strategy for pressure maintenance compared to CO2 injection, which has an NPV of $181.39 billion (Figure 8). In terms of profit margin over time, gas cycling, with an annual percentage value of 71.3, is again the most favorable strategy compared to CO2 injection, which has a percentage value of 66.8 (Figure 9). However, this evaluation suggests that CO2 injection could be considered, as it yields a productive profit margin over time. The decision-making process would benefit from a comprehensive economic evaluation.

Table 8 Economic Evaluation (Annual) of Injection (Gases) Study

Injection Type	Gas cycling	CO2 Injection
NPV ($B)	231.36	181.39
Profit Margin over Time (%)	71.3	66.8
ROI (%)	240	180
Cumulative Profit ($M)	1.2	0.9

Results also summarizes that the annual profit (cumulative) from gas cycling, estimated at $1.2 million, is greater than that of CO2 injection, estimated at $0.9 million. This further highlights the effectiveness of gas cycling, which yields an annual ROI of 240%, compared to CO2 injection's ROI of 180% (Figure 10). It is important to note that the impressive ROI of 180% for CO2 injection underscores its potential significance in decision-making.

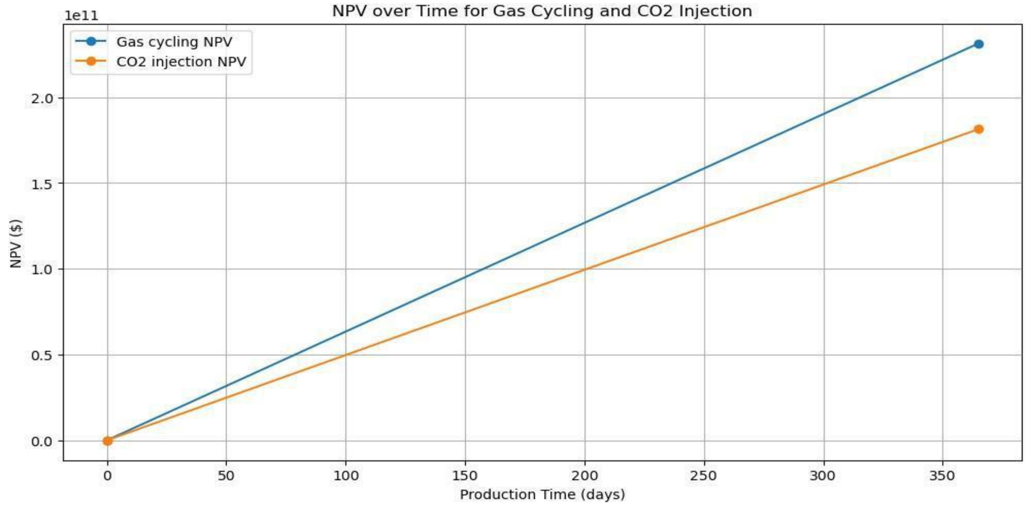


Fig. 8 NPV Evaluation (Annual) of Gas cycling and CO2 Injection

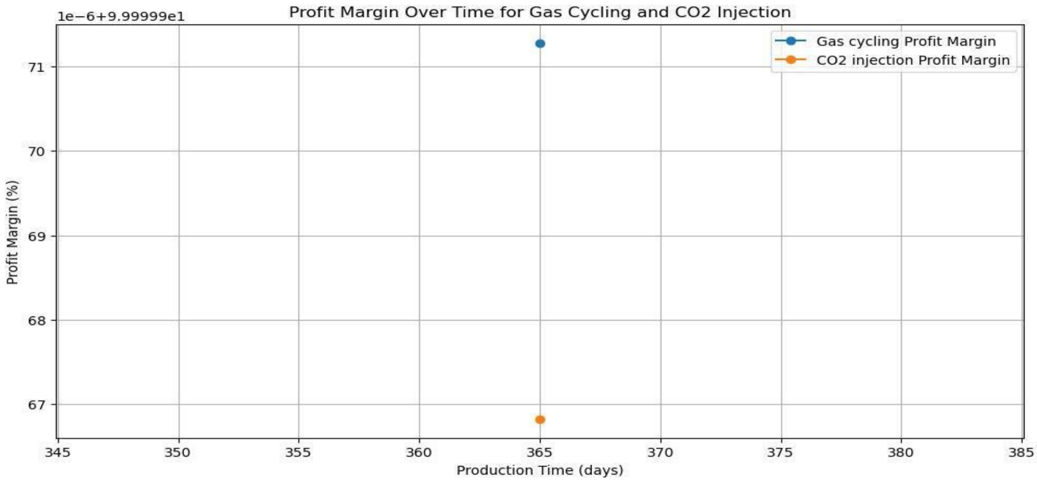


Fig. 9 Profit Margin over Time (Annual) of Gas cycling and CO2 Injection

However, other factors beyond economic considerations such as reservoir characteristics, production/injection time and environmental impact may also paly vital role in final decisions.

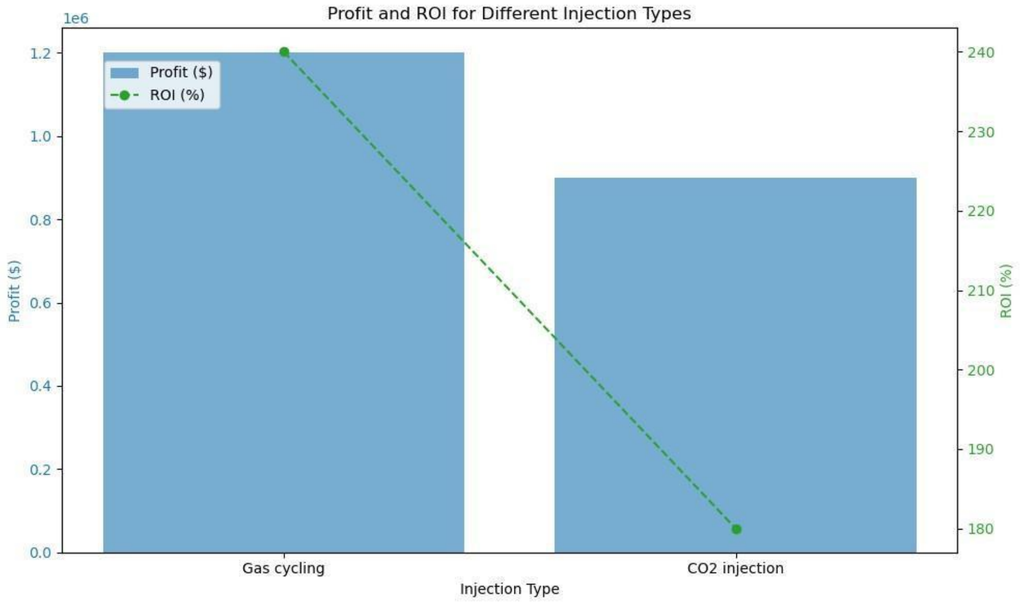


Fig. 10 Profit Margin over Time (Annual) of Gas cycling and CO2 Injection

4.2 Gas Cycling and CO2 Injection for Environmental Sustainability

Advancing environmental sustainability, CO2 injection is recognized as a crucial technology that offers dual benefits. By capturing and geologically sequestering carbon dioxide, this method mitigates the negative impact of excess greenhouse gases and also provide practical approach for industries to contribute to global climate goals. The significant volume of CO2 sequestered underscores its potential to substantially reduce global warming. This is a sequestration process that generates environmental credits, providing the economic incentives for industries to act according to sustainable practices. Based on production data summarized in Table 7, a calculation of approximately 29.6 million tons of annual CO2 sequestration amount follows, further evaluating these annual environmental credits. These environmental-credits are then incorporated into economic evaluations to compare the annual economic potential of CO2 injection and gas cycling, enhancing both economic and environmental sustainability.

Table 9 Estimation (Annual) of CO2 Geologic Storage and Environmental Credits

Injection Type	Geologic Sequestration/ Storage (M-tons)	Environmental Credits ($B)
CO2 injection	29.6	1.48

Table 9 contain results from CO2 injection reveal significant environmental and economic benefits. The process geologically sequesters 29.6 million metric tons of CO2 translates into $1.48 billion in environmental credits (Figure 11), underscoring the tangible economic incentives for adopting CO2 injection technologies.

Table 10 shows the results revised for the economic outcome in consideration of monetary value that can be created from CO2 sequestration and geological storage. Despite the inclusion of environmental credits, the Net Present Value (NPV) remains unchanged for both gas cycling and CO2 injection, at $231.36 billion and $181.39 billion respectively (Figure 12). This constancy suggests that the current NPV calculations do not account for revenues from carbon credits. NPV, in this context, continues to represent the present value of cash flows from the project exclusive of carbon credit sales.

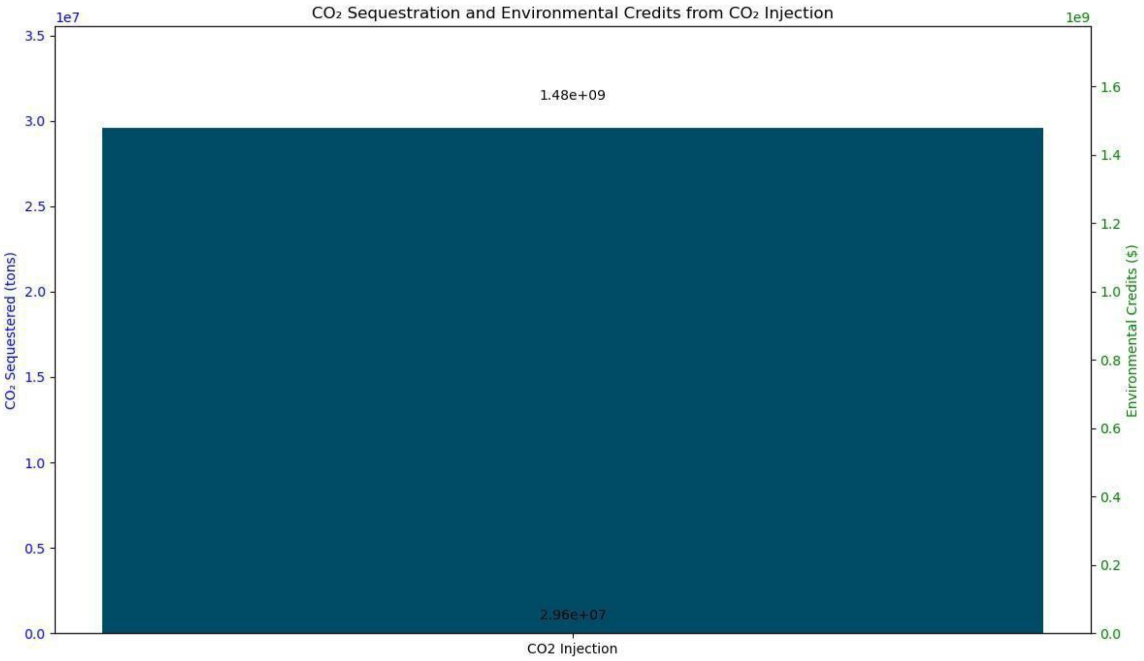


Fig. 11 Environmental-credits Evaluation (Annual) CO2 Sequestration/ Geological Storage

Table 10 Economic Evaluation (Annual) after considering CO2 Sequestration of Injection (Gases) Study

Injection Type	Gas cycling	CO2 Injection
NPV ($B)	231.36	181.39
Profit Margin over Time (%)	35	26.67
ROI (%)	140	80
Cumulative Profit ($M)	0.7	1.1

The metrics for Annual Profit Margin, Return on Investment (ROI), and Cumulative Profit show notable changes. For gas cycling, these metrics significantly decrease, while CO2 injection experiences a reduction but also shows a marginal improvement in cumulative profits (Figure 12). This shift indicates that the integration of environmental credits alters financial dynamics, significantly impacting how operational costs and additional revenues are assessed against initial investments. The apparent reduction in profitability and ROI, particularly for gas cycling, could be attributed to the costs associated with carbon sequestration, setup, and maintenance. These expenses can adversely affect profitability indicators, despite the potential for increased cumulative profits from CO2 injection. The decline in profit margins and ROI post-environmental credits underscores the financial implications of carbon sequestration costs.

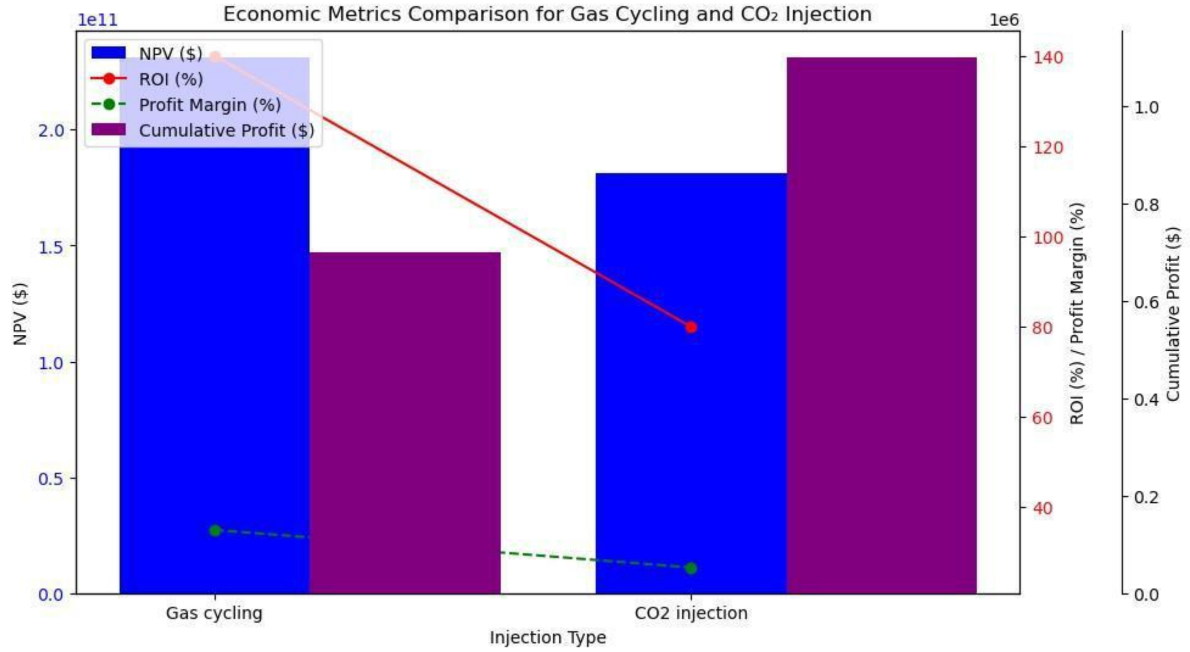


Fig. 12 Post-credits Economic Evaluations (Annual) of Gas cycling and CO2 Injection

Interestingly, CO2 Injection's Cumulative Profit improves, rising from 0.9 million to 1.1 million dollars (Figure 10 and Figure 12), which may be attributed to the incremental revenue from carbon credits. This enhancement emphasizes the potential economic benefits of environmental contributions over time. The observed increase in cumulative profit for CO2 injection, subsequent to accounting for carbon credits, illustrates that over time, revenues from carbon credits can sufficiently offset the initial and operational costs, potentially enhancing the long-term financial returns for projects that continue beyond the immediate study period of 01 year if further evaluated.

Gas cycling appears more profitable in traditional financial metrics, CO2 injection might be more aligned with long-term sustainability goals, potentially offering greater cumulative profits when carbon credits are considered. This signifies a strategic pivot toward sustainability, potentially attracting decision-makers focusing on environmental considerations.

5. Key Findings

This study has extensively analyzed the performance of gas cycling and CO2 injection in enhancing hydrocarbon recovery from a gas condensate reservoir. Our investigations revealed that both methods significantly improve condensate recovery, as demonstrated in the compositional simulations and summarized in Table 3 and Table 10, along with Figure 4, Figure 5 and Figure 6. Following are the key findings:

5.1 Efficacy of Gas Cycling and CO2 Injection

Both techniques showed potential in increasing hydrocarbon recovery rates, with gas cycling particularly notable for achieving a higher overall recovery rate of 78.2% in oil and 20% in gas. This was supported by its ability to maintain reservoir pressure and enhance the miscibility of the reservoir fluids.

CO2 injection, while yielding a lower recovery rate of 65.3% in oil and 11% in gas, was significant for its role in reducing oil viscosity and dissolving lighter hydrocarbons, which aids in more efficient hydrocarbon extraction.

5.2 Well Network Pattern

The study of nine-spot and five-spot well networks over a 19-year production scheme has revealed slight cost increases with the nine-spot pattern but improved condensate recovery by 1%. This underscores the importance of well spacing and network density in enhancing areal sweep efficiency and, consequently, recovery rates

5.3 Injection Parameters

Analysis of different injection pressures and flow rates in a nine-spot gas cycling setup indicates a trade-off between maximizing oil and gas recovery. Optimal settings depend on specific project goals and reservoir characteristics, with higher pressures favoring gas recovery and moderate flow rates providing a balance between oil recovery and economic feasibility.

5.4 Economic Impact Assessed Through Environmental Credits

The introduction of environmental credits for CO2 sequestration significantly altered the economic landscape. While gas cycling maintained a higher NPV and ROI in conventional economic terms, CO2 injection's role in environmental sustainability introduced substantial long-term financial benefits through environmental credits, reflected in an improved cumulative profit from \$0.9 million to \$1.1 million.

5.5 Strategic Implications for Future Applications

If gas cycling can have high returns economically, it is obvious that CO2 injection will be much more consistent with global goals of sustainability that allow for a balancing of economic outputs and environmental stewardship. Being able to gain the deck advantage environmentally clearly demonstrates that CO2 injection is one of the key strategies that industries can use toward being better environmental stewards.

6. Conclusions

This study is important to integrate engineering practices in petroleum production with the aim of optimizing operations. It provides the simulation details for well network patterns and gives the conditions that bring about injection schemes. An in-depth understanding of field dynamics, how technological, economic and environmental factors interplay to influence outcomes, is described.

Gas cycling and CO2 sequestration, besides contributing to energy security by improving the rate of recovery of condensate oil, represent both a circular carbon economy and a socioeconomically green solution: low-emissions, yet profitable.

The findings clearly indicate that recovery strategies designed according to the respective reservoir characteristics and operational objectives are very important to maximize the extracted resource. If the oil and gas industry is going to be more sustainable in the future, there is no doubt that economic assessment needs to go hand in glove with environmental factors. While new environmentally-friendly technology, such as CO2 sequestration, would have an adverse impact on project economics at the very beginning due to upfront costs, it will be compensated for by environmental and economic benefits in the long run with due investment.

7. Recommendations for Future Research

The effectiveness of both methods should be compared over a longer simulation period. This would help ascertain their effectiveness in reaching higher permeability zones and maximizing hydrocarbon recovery. Additional studies should consider the integration of CO2 injection with other enhanced recovery techniques to leverage both economic and environmental benefits more effectively.

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