



Optimization of miscible CO₂ injection in the Nasiriyah oil field using a history-matched compositional reservoir model

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Abstract

This study aims to evaluate and optimize the performance of miscible CO₂ injection in the heterogeneous Mishrif carbonate reservoir, with the objective of enhancing oil recovery and improving reservoir production performance. A compositional reservoir model was developed using CMG-GEM to accurately represent fluid behavior and phase transitions. Fluid characterization and PVT data matching were performed using WinProp with the Soave–Redlich–Kwong (SRK) equation of state. History matching of production and pressure data was also carried out to validate the reliability of the reservoir model. A natural depletion scenario was adopted as a base case for comparison, after which miscible CO₂ injection was implemented, and an optimization study was conducted using CMOST based on Latin Hypercube Sampling (LHS) and a proxy model to identify optimal operating conditions. The results of the natural depletion case showed a continuous decline in reservoir pressure, with a final recovery factor of only 2.74%. In contrast, CO₂ injection improved reservoir performance and increased the recovery factor to 4.22% in the optimized case, with delayed gas breakthrough and a reduced gas-oil ratio compared to the base case. The study confirms that miscible CO₂ injection is an effective enhanced oil recovery technique for the Mishrif reservoir, offering a significant increase in production while improving reservoir management and maintaining pressure support.

Keywords: Proxy Model; Miscible CO₂; Latin Hypercube Sampling; Optimization; CMOST; Enhanced oil recovery.

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1- Introduction

In conventional oil recovery projects, when primary production drops to an uneconomic level, different methods were developed to enhance oil recovery efficiency before reservoir abandonment [1]. Enhanced oil recovery is mainly classified into two types: thermal and non-thermal methods [2]. Non-thermal recovery methods include water flooding, gas injection and chemical processes. Thermal recovery refers to processes where heat is the main factor in improve oil recovery [3]. Gas injection is not only a pressure maintenance method that helps sustain reservoir pressure and increase the oil production rate, but it is also an important enhanced oil recovery by achieving miscibility [4]. Gas injection processes are generally classified into two main types: miscible and immiscible injection [5]. In miscible gas injection, the gas is injected at or above the Minimum Miscibility Pressure (MMP), allowing it to mix completely with the oil [6, 7]. In contrast, in immiscible gas injection, the process is carried out below MMP, so the gas does not fully mix with the oil [8]. This low-pressure gas injection is used to sustain reservoir pressure, to prevent production decline and thus enhance the production rate. An ideal condition in any gas injection project is to have the oil and gas phases completely mixed into a single phase at any feed composition [9-11]. Oil

recoveries for gas injection methods are generally higher when the process is conducted under conditions that allow the injected gas to become miscible with the reservoir oil [12, 13]. The main goal of miscible gas injection is to enhance local displacement efficiency and lower the remaining oil saturation to levels lower than those usually achieved by water flooding [14-16].

Within gas injection techniques, CO₂ is favored over hydrocarbon gases (HC) owing to its reduced cost, high displacement effectiveness and the possibility for associated environmental benefits through its sequestration inside the petroleum reservoir [17]. Utilizing CO₂ for Enhanced Oil Recovery (EOR) is considered one of the most prospective methods for profitable utilization [18]. The poor performance of gas in displacing oil is due to its natural properties of low viscosity and density, which lead to a phenomenon known as viscous fingering where the injected gas moves faster than the oil and forms continuous channels in the reservoir leaving behind areas of oil that have not been displaced, thereby reducing the overall oil recovery [19]. CO₂ injection methods differ in performance, as the performance of immiscible CO₂ injection is lower compared to of miscible CO₂ injection due to gas channels, gas fingering, and gravity segregation. On the other hand, in many cases it is difficult to reach the



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minimal miscibility pressure (MMP), This is a main reason for using immiscible injection in EOR [20]. Miscible CO₂ injection is an efficient method due to its low cost [21, 22]. CO₂ is characterized by the process of oil swelling and reduced viscosity as the dominant processes due to the partial dissolution of CO₂ in oil [23]. The solubility of CO₂ in oil is directly proportional to pressure and API gravity, and inversely proportional to temperature [24].

This paper aims to improve oil recovery in Mishrif formation in Nasiriyah oil field applying miscible CO₂ injection, The study focuses on identifying the optimal operating condition that maximize the oil recovery factor while minimizing gas production.

2- Reservoir properties

The Mishrif formation is a heterogeneous carbonate reservoir mainly composed of limestone [25-27]. It is characterized by variable porosity and permeability that significantly influence fluid flow and reservoir performance. The reservoir fluid is medium crude oil, with an API gravity of 28.4, supplied from one of the oil reservoirs in southern Iraq. The initial reservoir conditions and fluid properties summarized in Table 1.

Table 1. Initial reservoir conditions and fluid properties

API	Viscosity (cp)	GOR (SCF/STB)	Reservoir temperature (F)	Initial reservoir pressure (PSI)	Bubble point pressure (PSI)
28.4	1.129	535	163.4	3689	2190

3- Methodology

3.1. Development of the compositional reservoir model

A compositional reservoir model was developed using CMG software to accurately represent the phase behavior and physicochemical properties of fluids within the reservoir. Fluid characterization was performed using WinProp, where the Soave-Redlich-Kwong (SRK) equation of state was adopted to describe phase behavior as in Eq. 1 to Eq. 6 [28].

$$P = \frac{RT}{V-b} - \frac{a}{\sqrt{T}V(V+b)} \quad (1)$$

where

$$a(T) = a_c \alpha(T) \quad (2)$$

$$a_c = \frac{\Omega_a R^2 T_c^2}{P_c} \quad (3)$$

$$\Omega_a = 0.42747$$

$$b = \frac{\Omega_b RT_c}{P_c} \quad (4)$$

$$\Omega_b = 0.08664$$

$$\alpha(T) = \left(1 + m \left[1 - \sqrt{\frac{T}{T_c}}\right]\right)^2 \quad (5)$$

$$m = 0.480 + 1.574\omega - 0.176\omega^2 \quad (6)$$

The tuning (matching) process was performed using experimental PVT data by iteratively adjusting the EOS parameters to achieve the best agreement between experimental and calculated results. The matching process included several key properties representing reservoir fluid behavior. The idea of matching oil formation volume factor (FVF) aimed to accurately represent liquid phase expansion as shown in Fig. 1, while matching the solution gas-oil ratio (Rs) focused on correctly representing gas dissolution in oil as shown in Fig. 1. The concept of matching viscosity (μ) was used to represent realistic fluid flow behavior within the reservoir as shown in Fig. 2. In addition, oil specific gravity (SG) was matched as shown in Fig. 3 to ensure accurate representation of the oil phase, and finally, CCE was adjusted to refine the compositional representation of the fluid system as shown in Fig. 4. After achieving a good match between experimental data and EOS results, the final tube model was exported to the compositional simulator for reservoir simulation studies. This SRK-based compositional model provides an accurate representation of phase behavior and serves as a reliable foundation for reservoir performance analysis and enhanced oil recovery studies.

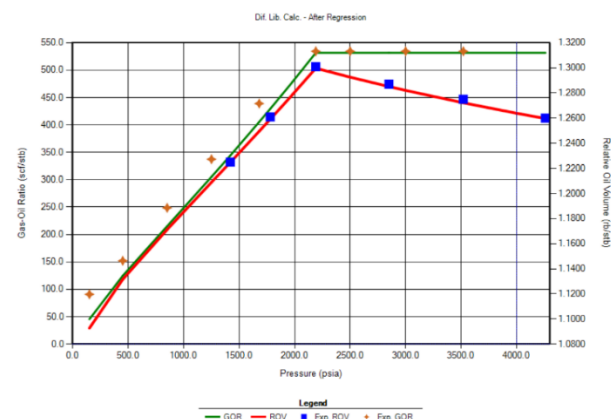


Fig. 1. Calculation vs observation of FVF and Rs

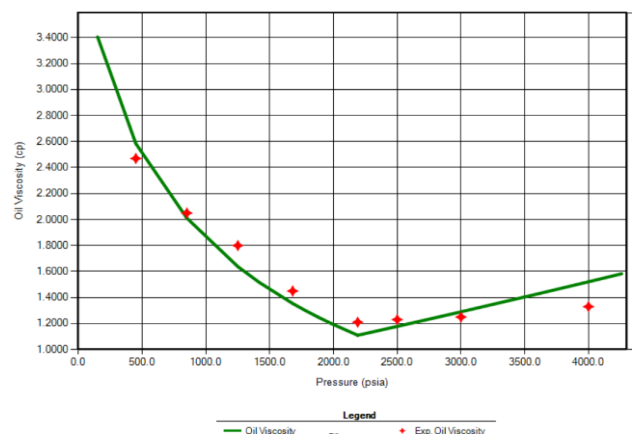


Fig. 2. Calculation vs observation of viscosity of the oil

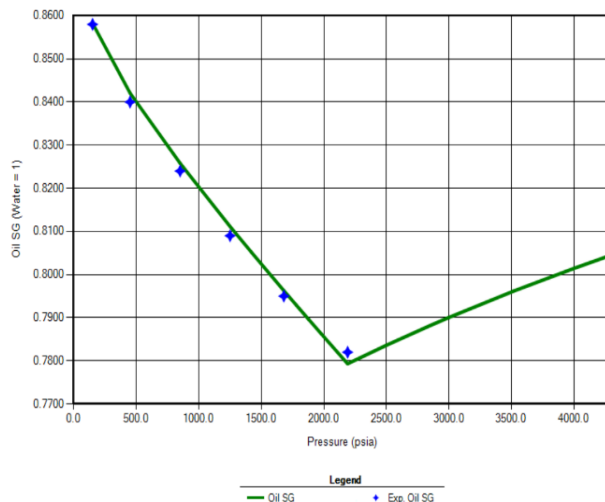


Fig. 3. Calculation vs observation of specific gravity of the oil

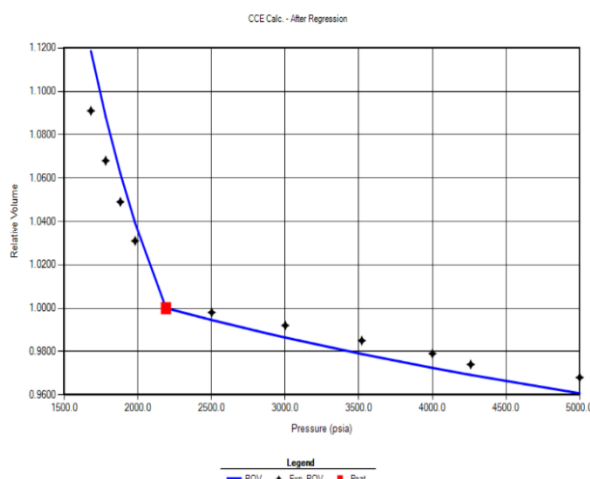


Fig. 4. Calculation vs observation of relative volume

After completing the EOS tuning process, the Minimum Miscibility Pressure (MMP) was determined, as it represents a key parameter in the design and evaluation of CO₂ injection projects. Due to the unavailability of experimental MMP measurements for the studied reservoir, the MMP was estimated using the Key Tie Line method available in WinProp. Based on the tuned EOS model, the calculated MMP value was 2225 psi. This value was subsequently used as a reference for evaluating the feasibility of miscible CO₂ injection in the reservoir.

3.2. Reservoir simulation model description

The static reservoir model was constructed in petrel 2022 by integrating geological, well, and petrophysical data. Well locations, formation tops, and structural contour maps were imported to establish the structural framework of the Mishrif Formation. The reservoir was then discretized into a 3D grid, and properties (porosity, permeability, water saturation) were upscaled and distributed throughout the model using sequential

gaussian simulation (SGS). The completed static model was subsequently exported to CMG for dynamic reservoir simulation. The model includes the distribution of porosity, permeability, net-to-gross (NTG) and water saturation to accurately represent reservoir heterogeneity. The three-dimensional reservoir model is presented in Fig. 5, while Porosity distribution is shown in Fig. 6, permeability distribution in Fig. 7, water saturation distribution in Fig. 8, and net-to-gross (NTG) distribution in Fig. 9. The static model was then converted into a dynamic simulation model using CMG to study the fluid flow behavior within the reservoir under different operating conditions. In this study only 14 production wells (NS-2, NS-4, NS-7, NS-9, NS-10, NS-11, NS-12, NS-14, NS-17, NS-18, NS-20, NS-25, NS-36, and NS-41) from the Mishrif Formation in the Nasiriyah Oil Field were used for production rate history matching, while four wells (NS-2, NS-4, NS-10, NS-17) were used for pressure history matching. The matching results indicate a good agreement between the simulated and actual field data. Fig. 10 represents the oil rate, while Fig. 11 represents the pressure history matching.

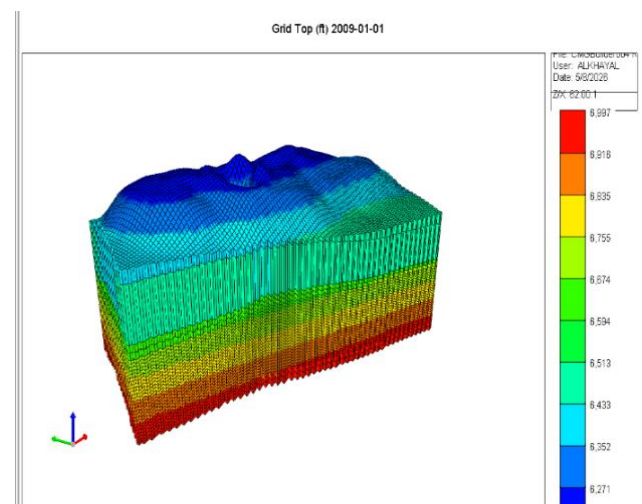


Fig. 5. 3D simulation model in GEM

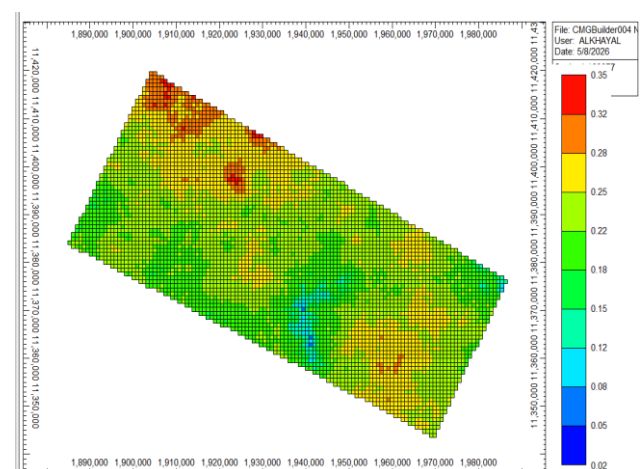


Fig. 6. Porosity distribution

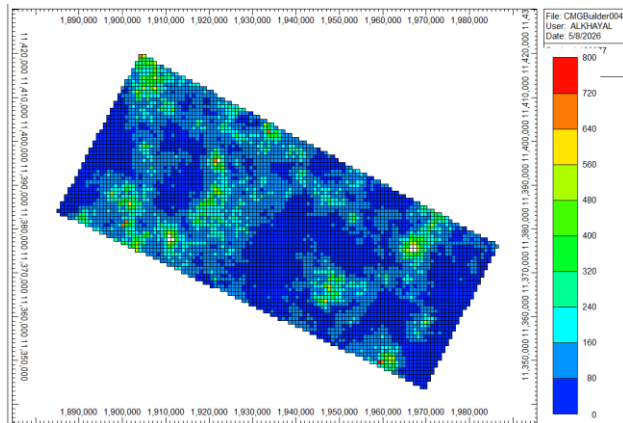


Fig. 7. permeability distribution

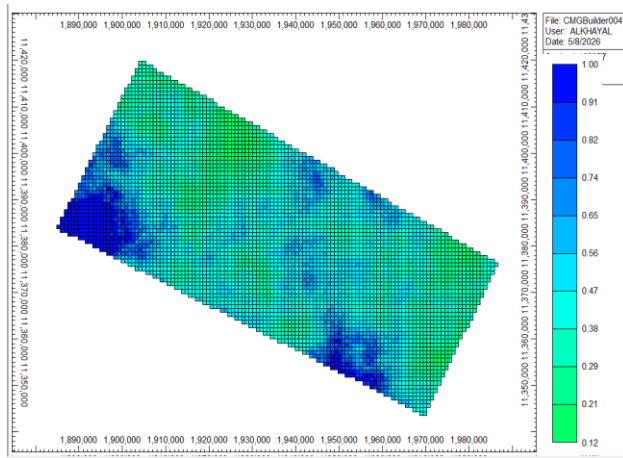


Fig. 8. water saturation distribution

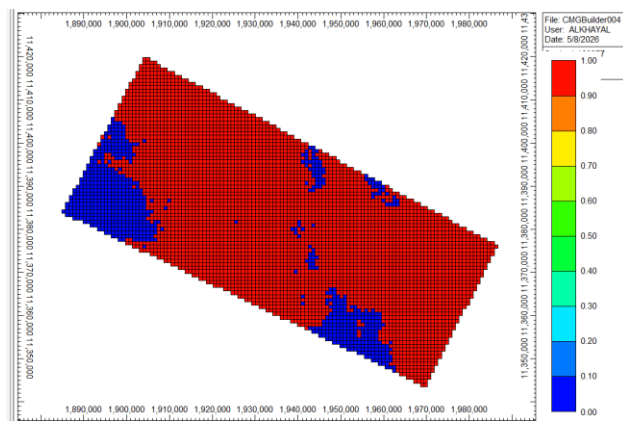


Fig. 9. Net-to-gross (NTG) distribution

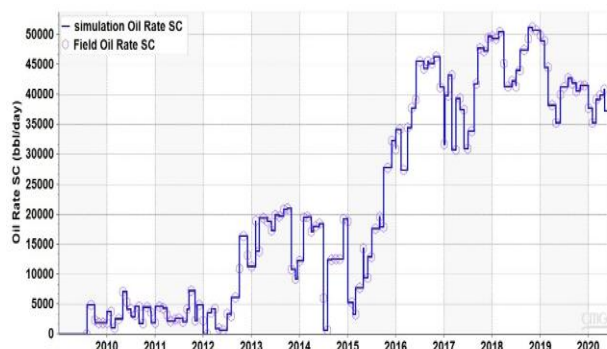


Fig. 10. Field oil rate match

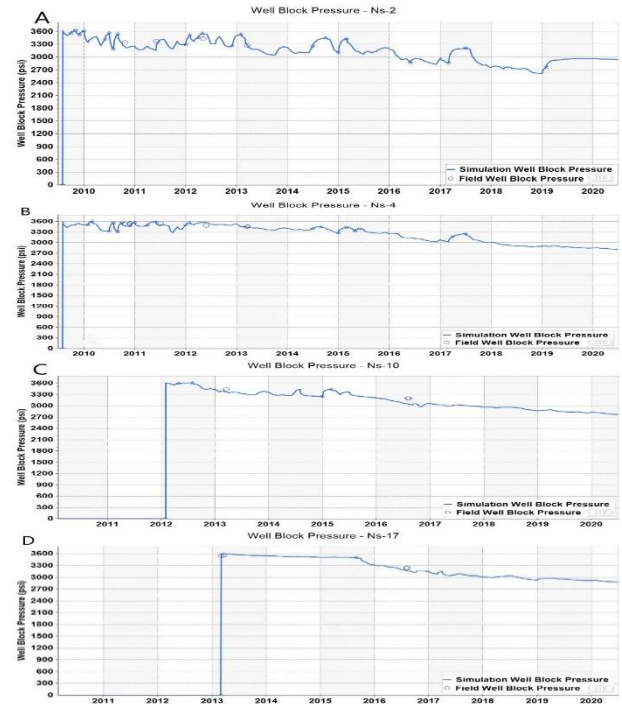


Fig. 11. Pressure match for: (A) NS-2, (B) NS-4, (C) NS-10, (D) NS-17

4- Results and discussion

4.1. Natural depletion scenario

The simulation was first conducted under natural depletion conditions without gas injection, which was adopted as a base case for comparison with the subsequent development scenario. A history matching process was performed using production data from 2009 to 2020 to ensure the accuracy and reliability of the reservoir model. In addition, actual historical production data were used for the period from 01/08/012009 to 01/05/2020 to ensure a realistic representation of reservoir behavior during the simulation period. After 01/05/2020, the natural depletion case was continued within the simulation model, while operational constraints were applied, including a constant oil production rate of 10,000 STB/day per well and a bottom-hole pressure (BHP) of 2190 psi, which is equal to the reservoir bubble point pressure. This pressure was selected to avoid excessive pressure decline in the reservoir and to minimize early gas liberation, which could lead to an increase in the gas-oil ratio (GOR). To reduce the simulation run time and focus on representative area of the reservoir, a sector model was developed instead of simulating the full-field model. Fig. 12 illustrates the selected sector and the study wells included in the model. The study included 14 production wells, namely wells NS-2, NS-4, NS-7, NS-9, NS-10, NS-11, NS-12, NS-14, NS-17, NS-18, NS-20, NS-25, NS-36, and NS-41 within the selected sector model.

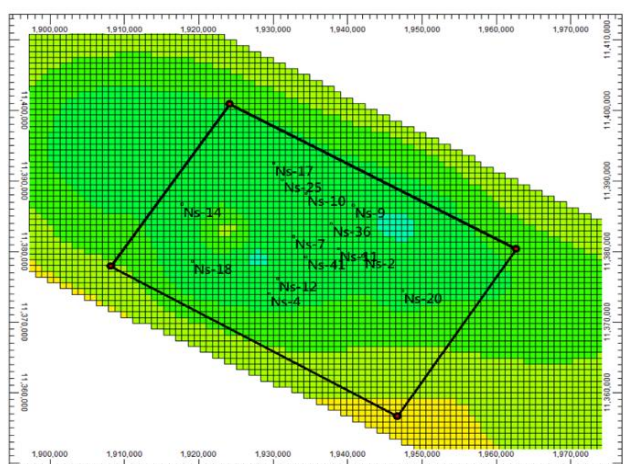


Fig. 12. The selected area for sector modelling

The results of the natural depletion case included the evaluation of several key reservoir performance indicators, where the results showed reservoir pressure, gas-oil ratio (GOR), and recovery factor (RF) over time as illustrated in Fig. 13. At the beginning of the production period, the reservoir pressure remained relatively high, with a gradual decline due to the limited number of producing wells. Between 2015 and 2020, after all production wells became operational, the increased fluid withdrawal accelerated the pressure decline. After 2020, a more pronounced decrease in reservoir pressure was observed following the implementation of the operational constraints, in addition to the continued depletion of reservoir energy caused by ongoing production.

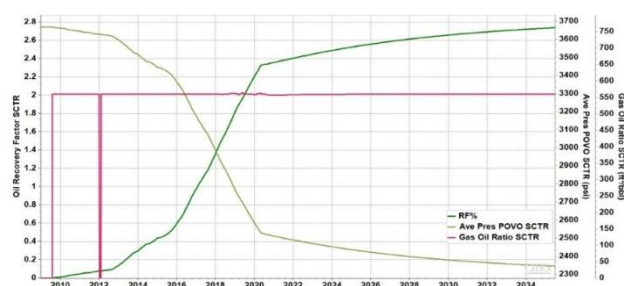


Fig. 13. Reservoir performance and production forecast

Meanwhile the behavior of oil production rate is presented in Fig. 14. The simulation results showed a gradual decline in reservoir pressure due to continuous production without external pressure support. The pressure continuously decreased over time as a result of the depletion of natural reservoir energy, reaching a final reservoir pressure of 2345 psi at the end of the production period, as shown in Fig. 14. This led to a progressive decline in oil production rate throughout the production period.

The results also showed that the gas-oil ratio remained nearly constant during the production period with no significant change. This is due to the imposed production pressure constraint at the bubble point pressure (P_b), which limited gas liberation within the reservoir and maintained a stable GOR behavior. Accordingly, the GOR response reflects the effect of operational

constraints on production wells rather than changes in reservoir pressure. water production remained limited during the natural depletion period. at the end of the simulation period in 2035 the final recovery factor RF reached 2.74%. The results of the natural depletion case were adopted as the base case for comparison with the gas injection enhanced oil recovery scenarios. This was done to evaluate the impact of injection processes on improving reservoir performance by measuring the improvement in production rates pressure maintenance and recovery factor relative to the natural depletion case.



Fig. 14. Field oil production rate

4.2. Optimization miscible CO₂ injection scenario

The reservoir model consists of six vertical injection wells and 14 vertical production wells distributed within the reservoir. This configuration was selected to achieve adequate pressure support and improve sweep efficiency during the gas injection process. The well locations were designed to enhance oil recovery and minimize early gas breakthrough. Fig. 15 presents the locations of the injection and production wells used in this study.

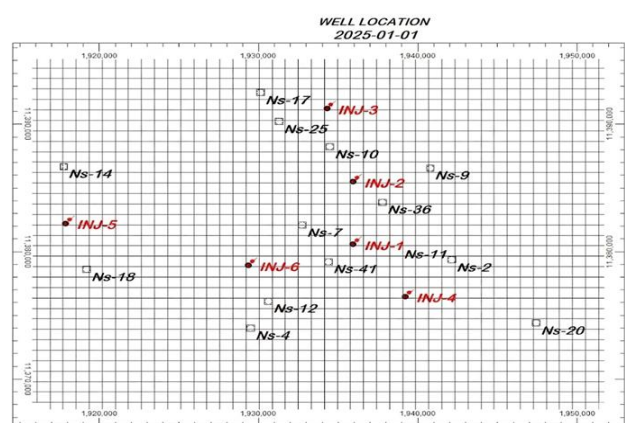


Fig. 15. locations of the injection and production wells

The production well operating constraints, the same operational limits and sector used in the natural depletion scenario were applied. The main optimization approach used in this scenario is the design of experiments (DoE) using the Latin Hypercube Sampling method combined with a Proxy Model. Latin Hypercube Sampling (LHS) was used to generate a minimum number of simulations runs while ensuring wide coverage of the input parameter space. The training dataset for the Proxy Model was

generated from simulation results obtained through LHS-designed experiments. This dataset was then used to develop and train the Proxy Model. This significantly accelerated the optimization process and enabled faster convergence to the optimum solution while maintaining acceptable accuracy. Fig. 16 illustrates the values of recovery factor (RF) for all simulation runs generated during the optimization process in CMOST. Each point represents a simulation run with a specific ID, showing the impact of varying operational parameters on reservoir performance and production behavior. The cases start 1, start 2, start 3, start 4, and start 5 represent the optimum points obtained from the optimization process.

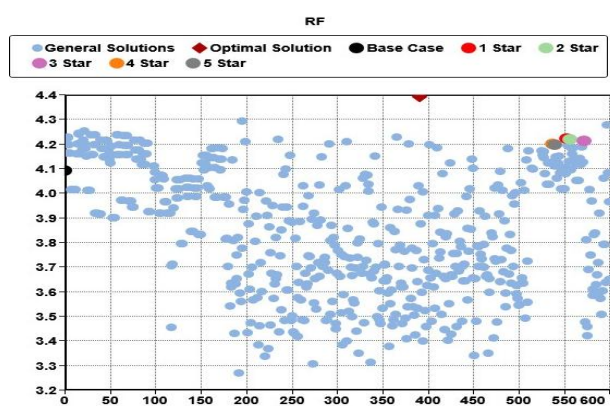


Fig. 16. Recovery factor for all cases generated by LHS

At the end of the runs, it is observed that the recovery factor (RF) ranges from 3.27% to 4.39%. Fig. 17 and Fig. 18 presents the selected optimum scenarios together with the base case. These scenarios were selected from the total number of simulations runs based on recovery factor, Gas-Oil Ratio and production rate. These scenarios represent the best solutions obtained from the optimization process after evaluating all executed runs. In addition, the CMOST scenario (red curve) represents the optimum solution automatically selected by the CMOST tool based on the objective function (RF) and operational constraints defined within the optimization process. As shown in Fig. 17 and Fig. 18, seven scenarios are presented, including one base case and six optimized scenarios. In the base case the recovery factor reached 4.09% with a relatively higher GOR of 1977 scf/STB. Furthermore, early gas breakthrough occurred at the beginning of 2026, approximately one year after the start of CO₂ injection. For the optimum scenario obtained from CMOST the recovery factor increased to 4.39% while the GOR decreased to 1636 scf/STB. In addition, gas breakthrough occurred later compared with the base case, taking place in January 2027, nearly two years after the start of injection. Regarding the Star-1 to Star-5 scenarios, all scenarios showed a noticeable delay in gas breakthrough during the simulation period. Star-1 achieved the recovery factor of 4.22% with GOR of 1075 scf/STB, while Star-2 achieved the recovery factor of 4.22% with GOR of 1055 scf/STB. Star-3 recorded a recovery factor of 4.21% with GOR of 1102 scf/STB,

Star-4 achieved the recovery factor of 4.20% with GOR of 1104 scf/STB. Finally, Star-5 recorded a recovery factor of 4.199% with GOR of 1067 scf/STB. The variation in the results and gas breakthrough timing among the scenarios is mainly attributed to changes in injection rates, perforation locations, and injection pressures applied for each well, which directly affected gas movement within the reservoir and the sweep efficiency. In general, the star scenarios exhibited a significant delay in gas breakthrough time, occurring after approximately four and a half years of injection, specifically around mid-2029.

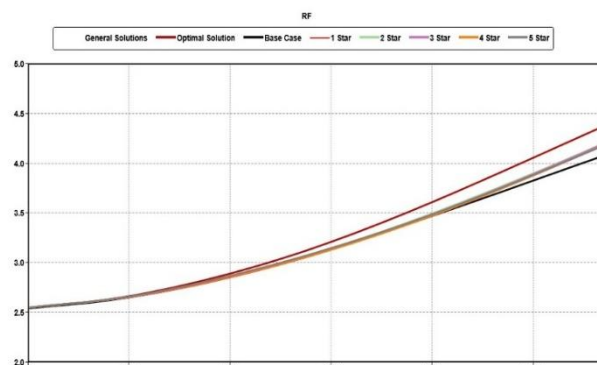


Fig. 17. Recovery Factor for optimum scenarios and base case

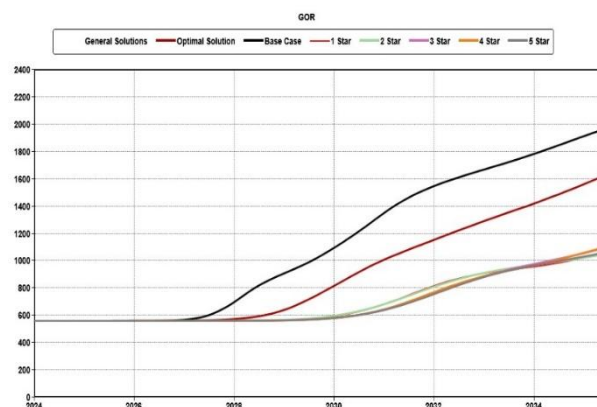


Fig. 18. Gas-Oil Ratio for optimum scenarios and base case

For scenarios 1 to 5, scenario one shows the lowest oil rate at the beginning of injection compared to the other scenarios. However, it continues to increase gradually until it reaches the highest final oil rate of approximately 23792 bbl/day at the end of the simulation period, making it the highest-producing scenario among all cases scenarios 2, 3, 4, and 5 also show continuous increase in production throughout the simulation period as shown in Fig. 19.

After completing all optimization stages and analyzing the simulation results, scenario 1 was selected as the optimum case for comparison with natural depletion case. The operational constraints and optimum variable values corresponding to the selected optimum scenario are presented in Table 2.

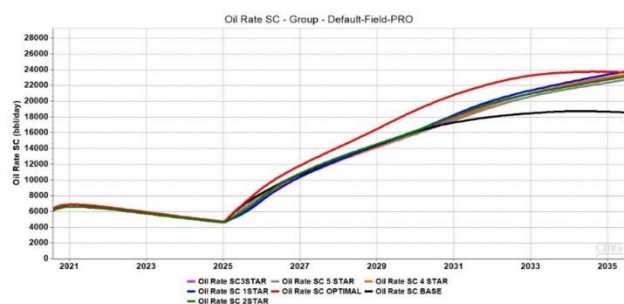


Fig. 19. Oil rate for optimum scenarios and base case

Table 2. Optimum operational parameters

Well	Injection rate (Mscf/day)	perforation	injection pressure (psi)
Injection-1	12000	bottom	5000
Injection-2	15000	bottom	3750
Injection-3	15000	middle	5000
Injection-4	14000	top	5000
Injection-5	14000	middle	5000
Injection-6	6000	bottom	5000

Fig. 20 compares the reservoir pressure curves for the natural depletion case and the selected optimum CO₂ injection scenario, illustrating the effect of CO₂ injection on pressure maintenance throughout the simulation period.



Fig. 20. Reservoir pressure comparison

5- Conclusions

This study evaluated the performance of miscible CO₂ injection in the Mishrif Formation of the Nasiriyah Oil Field using a history-matched compositional reservoir simulation model. The main findings and conclusions are summarized below:

- The natural depletion scenario demonstrated limited recovery efficiency, with a final recovery factor of 2.74% in a continuous decline in reservoir pressure throughout the simulation period.
- Miscible CO₂ injection improved reservoir performance by enhancing the displacement efficiency of residual oil.
- The optimization methodology based on Latin Hypercube Sampling (LHS) and proxy modeling proved effective in reducing the number of simulation runs an accelerating convergence toward the optimal solution.

- The optimized CO₂ injection case achieved a recovery factor of 4.224% compared to 2.74% in the natural depletion case, representing an increase of approximately 60% in oil recovery.
- The optimization process delayed gas breakthrough from approximately one year in the base case to about 4 and a half years in the optimized scenarios, which positively impacted production sustainability.
- Optimal operating conditions help reduce the gas-oil ratio in improved reservoir sweep efficiency by controlling gas movement and minimizing preferential flow channels.
- Injection rates, injection pressures, and perforation locations were identified as the most influential parameters affecting injection performance and oil recovery efficiency.
- The study confirms that miscible CO₂ injection is a promising option for developing the Mishrif reservoir in the Nasiriyah oil field and can be effectively applied to enhance oil recovery and improve ultimate recovery performance.

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Nomenclature

a_c	Attraction parameter at critical conditions
API	American Petroleum Institute
b	Co-volume parameter
B	Dimensionless compressibility parameter
BHP	Bottom-hole pressure (psi)
CCE	Constant Composition Expansion
CMG	Computer Management Group
CO ₂	Carbon dioxide
EOR	Enhanced oil recovery
EOS	Equation of state
FVF	Formation volume factor (bbl/STB)
GOR	Gas-oil ratio (scf/STB)
LHS	Latin Hypercube Sampling
M	Molecular weight
MMP	Minimum miscibility pressure (psi)
NTG	Net-to-gross ratio
P	Pressure
P_c	Critical pressure
PVT	Pressure–Volume–temperature
R	gas constant
RF	Recovery factor %
R_s	Solution gas-oil ratio
SG	Specific gravity
SRK	Soave–Redlich–Kwong
T	Temperature
T_c	Critical temperature
V	Molar volume
α	Temperature-dependent correction factor
ω	Acentric factor

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تحسين عملية حقن ثاني أكسيد الكربون الممتزج في حقل الناصرية النفطي باستخدام نموذج مكمني تركيبي مطابق تاريخياً

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الخلاصة

تهدف هذه الدراسة إلى تقييم وتحسين أداء حقن ثاني أكسيد الكربون القابل للامتزاج في مكمن المشرف الكربوني غير المتجانس، بهدف تعزيز استخلاص النفط وتحسين أداء إنتاج المكمن. حيث تم تطوير نموذج تركيبي للمكمن باستخدام برنامج CMG-GEM لتمثيل سلوك الموائع وتحولات الطور بدقة. أُجري توصيف الموائع ومطابقة بيانات PVT باستخدام برنامج WinProp مع معادلة حالة Soave-Redlich-Kwong (SRK). كما أُجريت مطابقة تاريخية لبيانات الإنتاج والضغط للتحقق من موثوقية نموذج المكمن. تم اعتماد سيناريو النضوب الطبيعي كحالة أساسية للمقارنة، وبعد ذلك تم تطبيق حقن ثاني أكسيد الكربون القابل للامتزاج، وأُجريت دراسة تحسين باستخدام برنامج CMOST القائم على أخذ عينات مكعب لاتيني فائق (LHS) ونموذج بديل لتحديد ظروف التشغيل المثلى. أظهرت نتائج حالة النضوب الطبيعي انخفاضاً مستمراً في ضغط المكمن، مع عامل استخلاص نهائي لا يتجاوز ٢,٧٤%. في المقابل، حسن حقن ثاني أكسيد الكربون أداء المكمن ورفع عامل الاستخلاص إلى ٤,٢٢% في الحالة المحسنة، مع تأخير في اختراق الغاز وانخفاض نسبة الغاز إلى النفط مقارنةً بالحالة الأساسية. تؤكد الدراسة أن حقن ثاني أكسيد الكربون القابل للامتزاج تقنية فعالة لتعزيز استخلاص النفط من مكمن المشرف، إذ تُحقق زيادة ملحوظة في الإنتاج مع تحسين إدارة المكمن والحفاظ على دعم الضغط.

الكلمات الدالة: نموذج بديل، ثاني أكسيد الكربون القابل للامتزاج، أخذ عينات مكعب لاتيني فائق، التحسين، استخلاص النفط المعزز، CMOST.