Energy Proceedings
Vol 51, 2025
ISSN 2004-2965

Study on the Mechanism of CO_2 Injection in Fractured-vuggy Carbonate Gas Condensate Reservoirs#

Fei Peng [1], Keliu Wu [1*], Longjie Ma [2], Yun Zhang [2], Zongyu Li [2]

1 China State Key Laboratory of Petroleum Resources and Prospecting, China University of Petroleum (Beijing), Beijing 102249

2 Research Institute of Petroleum Exploration and Production, Sinopec Northwest Oil Field Company , Urumqi, Xinjiang 830011
(Corresponding Author: wukeliu19850109@163.com)

ABSTRACT

Unlike conventional fractured-vuggy carbonate reservoirs, the gas condensate reservoir in fault zone of Shunbei belongs to a thick reservoir controlled by faults, with a gas column heights of up to 400-600 meters and gravity segregation. Clarifying the mechanism of gas injection development in the carbonate gas condensate reservoirs controlled by faults can provide important theoretical guidance for the development plans of gas injection and pressure maintenance. Firstly, for the purpose of miscible flooding, enhancing condensate oil recovery, and CCUS, CO_2 was chosen as the injection medium. Then, a geological model was established based on a typical well group in Fault Zone of Shunbei, and the best gas injection location was selected by considering the gravity segregation and combining the mechanism of gas injection to reducing condensate damage in gas condensate reservoirs. Finally, the optimization of gas injection was conducted and the optimal injection timing, injection strategy and injection rate was selected. The results indicate that:

1. Compared to bottom gas injection, top gas injection is the optimal location to obtain a better recovery rate of condensate oil for the gas condensate reservoir in fault zone of Shunbei.
2. The optimal gas injection timing is when the reservoir pressure drops to the dew point pressure.
3. The optimal gas injection strategy involves continuous gas injection in the early stage to maintain pressure, periodic gas injection in the mid-term, and depletion development in the later stage.
4. The optimal gas injection rate for the well group in Shunbei area is 350,000 cubic meters of CO_2 per day.

In the actual development of gas condensate reservoirs, gas injection and development plans should be developed based on the gas injection mechanism and considering the feasibility and economics This study can provide reference for the efficiency of gas injection for enhancement of condensate recovery in a gas condensate reservoir.

Keywords: fractured-vuggy carbonates, gas condensate reservoirs, gravity segregation, gas injection mechanism, CCUS

NONMENCLATURE

Abbreviations	
CCUS	Carbon Capture, Utilization and Storage

1. INTRODUCTION

The Shunbei-1 well, situated in the northern region of the Tarim Basin, signifies the commencement of the development of Shunbei Oilfield[1]. In recent years, a large number of studies have been conducted by scholars, focusing on the formation mechanisms of deep and ultra-deep vuggy carbonate reservoirs. These endeavors have culminated in the identification of the ultra-deep fractured-vuggy reservoirs in the Shunbei region as not only excellent conduits for oil and gas migration but also highly conducive spaces for oil and gas accumulation[2-3]. In comparison to the karst weathered crust carbonate reservoirs found in the Tazhong area[5,10,12], the fractured-vuggy reservoirs in the Shunbei region exhibit substantial disparities in terms of the characteristics of reservoir and the features of seismic response[4,5]. The spatial distribution of fractured-dissolved reservoirs is predominantly governed by fault zones and possesses distinctive attributes of interlayering, irregularity, and discontinuity[13,14]. Specifically, the gas condensate reservoir within a specific fault zone in the Shunbei exemplifies a prototypical fractured-dissolved reservoir characterized by the formation of narrow yet deep caves or fractures, with gas column heights of up to 400-600 meters. Furthermore, the condensate oil and gas exhibit significant density variations, giving rise to pronounced

This is a paper for the 16th International Conference on Applied Energy (ICAE2024), Sep. 1-5, 2024, Niigata, Japan.

gravity segregation, resulting in discernable differences in vertical distribution of compositions and gas-oil ratios.

For gas condensate reservoirs with the reservoir pressure significantly higher than the dew point pressure, the depletion is commonly employed in the early stages of development[8]. In the mid to later stages, the pressure maintenance system is implemented to enhance condensate recovery[6-9]. In the gas condensate reservoirs with a gas column heights of up to 400-600 meters, a notable phenomenon of gravity segregation occurs during the gas injection, whereby the composition of oil and gas and the gas-oil ratio exhibit significant variations across different reservoir layers[15-18]. Some researchers conducted experiments to simulate the dynamic process of injecting CO_2 or dry gas into gas condensate reservoirs. Utilizing visualization experimental facilities, they observed the thorough diffusion and mixing of the injected gas with the fluid inside the pipe, leading to the gravity segregation along the vertical direction. When the injection pressure approximates the dew point pressure of the reservoir fluids, a distinct three-phase coexistence of dry gas, gas condensate, and condensate oil is observed vertically from top to bottom, characterized by immiscible phase[22,23]. Some researchers investigated the optimal timing for gas injection in gas condensate reservoirs through experimental approaches[19]. Although these experiments were simplified and the pressure–volume–temperature data were measurement in a piston cylinder instead of in the porous media, the segregation phenomenon observed during the experiment hold significant reference value for parameter optimization during gas injection in such reservoirs. Furthermore, numerical simulations were employed to study the variation of oil-gas interface and the impact of the gas injection rate on the ultimate recovery in reservoirs considering the gravity segregation[24,25].

In this study, we combined the aforementioned experimental findings with numerical simulation methods to reveal the mechanism of gas injection in gas condensate reservoirs in the Shunbei region, and the optimization of gas injection was conducted, which could provide insights for the efficient development of similar gas condensate reservoirs.

2. GAS INJECTION MECHANISM

2.1 Development characteristics of the gas condensate reservoir in Shunbei area

During the initial depletion development stage, the average reservoir pressure drop indicate insufficient natural energy in the reservoir. Despite the original reservoir pressure of a typical well being 91.24 MPa and the dew point pressure being 43.30 MPa, the measured bottom hole pressure exhibits a significant annual variation of up to 22 MPa (Fig. 1). If the depletion development continues, the average reservoir pressure quickly declines below the dew point pressure, resulting in the occurrence of retrograde condensation and severely reducing gas well productivity and the ultimate recovery of condensate oil and gas. Moreover, the gas condensate reservoir in the Shunbei fault zone is characterized by a massive stratified reservoir with significant gravity segregation, which exacerbates the complex phase behavior of condensate oil and gas. Therefore, there is an urgent need to investigate the gas injection development mechanisms and optimize the gas injection parameters for such gas condensate reservoirs.

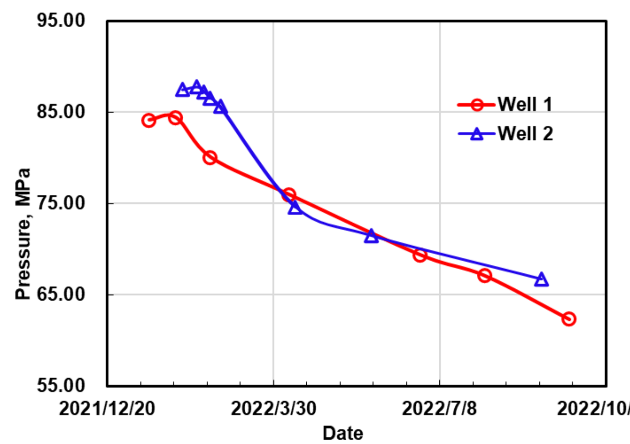


Fig. 1 Comparison of the bottom hole pressure of different well in Shunbei area

2.2 Pressure maintenance

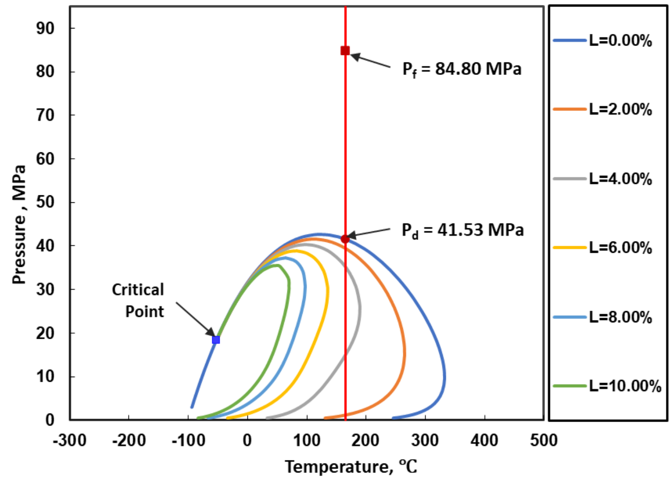
Introduction presents background information on the objectives, research questions and scope/limitation of the paper. During the pressure depletion process of a gas condensate reservoir, phase changes occur in the condensate oil and gas system when the reservoir pressure falls below the dew point pressure[26]. As shown in Fig. 3, a certain well in the Shunbei fault zone has an original formation pressure of 91.24 MPa and a dew point pressure of 43.30 MPa, resulting in a pressure difference of 47.94 MPa. When the reservoir pressure is higher than the dew point pressure, the reservoir fluid exists as a single-phase gas, and production can be achieved through the natural expansion of the gas itself, referred to as depletion development. However, when the reservoir pressure decreases to the dew point pressure or below, retrograde condensation occurs in the reservoir, leading to the precipitation of condensate oil and the blockage of gas flow channels, thereby reducing the gas permeability, especially in the near-wellbore zone[27,28]. This retrograde condensation-induced blockage phenomenon is more severe, resulting in decreased gas well productivity and condensate oil recovery. Therefore, injecting suitable fluids into the reservoir to maintain reservoir pressure or slow down pressure decline can suppress or delay retrograde condensation, improve condensate oil recovery, and is known as pressure maintenance for gas condensate reservoirs[29,30].

In the Shunbei area, a certain fault zone exhibits a significant vertical span in its massive reservoir, and the phase behavior of condensate oil and gas varies at different depths (Fig. 2). As the depth increases, the temperature and pressure of the formation rise, leading to an increase in the heavy component content and dew point pressure of the reservoir fluid. The moment when the pressure reaches the dew point pressure is an important reference indicator for optimizing the gas injection timing[19], and the formation pressure and dew point pressure vary at different locations at the same moment. Therefore, when designing gas injection pressure maintenance development schemes, it is necessary to consider the variations in the phase behavior characteristics of condensate oil and gas in different producing layers, select the optimal gas injection positions and timing, and achieve the goal of suppressing retrograde condensation through gas injection[29].

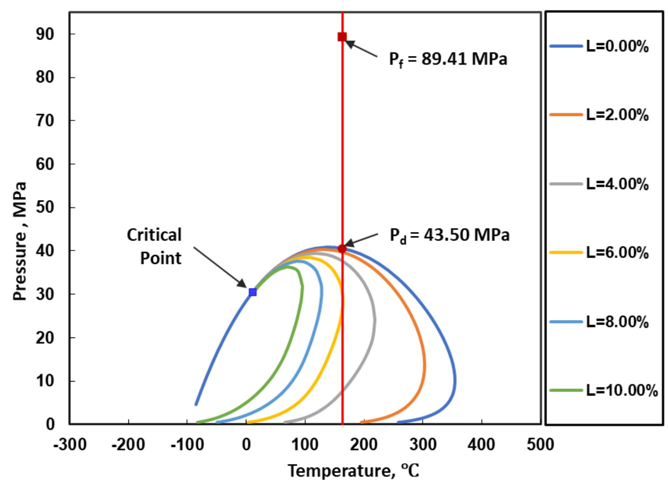
2.3 Injection medium

In the development of gas condensate reservoirs through gas injection for pressure maintenance, commonly used injection mediums include dry gas, carbon dioxide, and nitrogen[34-39]. In comparison to nitrogen and dry gas, carbon dioxide not only exhibits excellent pressure maintenance properties but can also be miscible with the condensate oil in the reservoir, enhancing its mobility. Furthermore, an increase in the CO_2 mole fraction in the gas condensate system can reduce the system's dew point pressure, maximum retrograde pressure, and decrease the maximum retrograde oil volume. Moreover, injecting CO_2 into the reservoirs has significant benefits for advancing CCUS to commercial-scale. Therefore, CO_2 was selected as the injection medium in this work.

2.4 Gravity Segregation



(a) Phase diagrams of the fluid on the top of the reservoir



(b) Phase diagrams of the fluid on the bottom of the reservoir

Fig. 2 Comparison of phase diagrams at different depths in the reservoir

The phase behavior varies at different depths in the super thick gas condensate reservoirs in Shunbei area(Fig. 2). Gravitational effects and other factors such as the density differences between different components result in higher gas-oil ratios and lower heavy component contents at the top of the reservoir, while the gas-oil ratios are lower and heavy component contents are higher at the bottom of the reservoir. This phenomenon is known as gravity segregation[31]. Gravity segregation is a crucial factor that cannot be neglected in the gas injection of the super thick reservoirs. Various researchers have observed this phenomenon through condensate gas displacement diffusion experiments[22,28], and there have been studies both domestically and internationally focusing on utilizing gravity segregation in different types of oil and gas reservoirs for pressure maintenance and production of crude oil or natural gas[24,31-33].

As the depth increases, the formation temperature and pressure rise, leading to an increase in heavy component content and dew point pressure of the formation fluid. The moment when pressure drops to the dew point pressure is a critical indicator for selecting the optimal gas injection timing[19], and the formation pressures and dew point pressures vary at different locations at the same time. Therefore, during gas injection, it is essential to consider the differences in the phase characteristics of condensate oil and gas in oil reservoirs at different depths, and to select the best gas injection locations and timing[29].

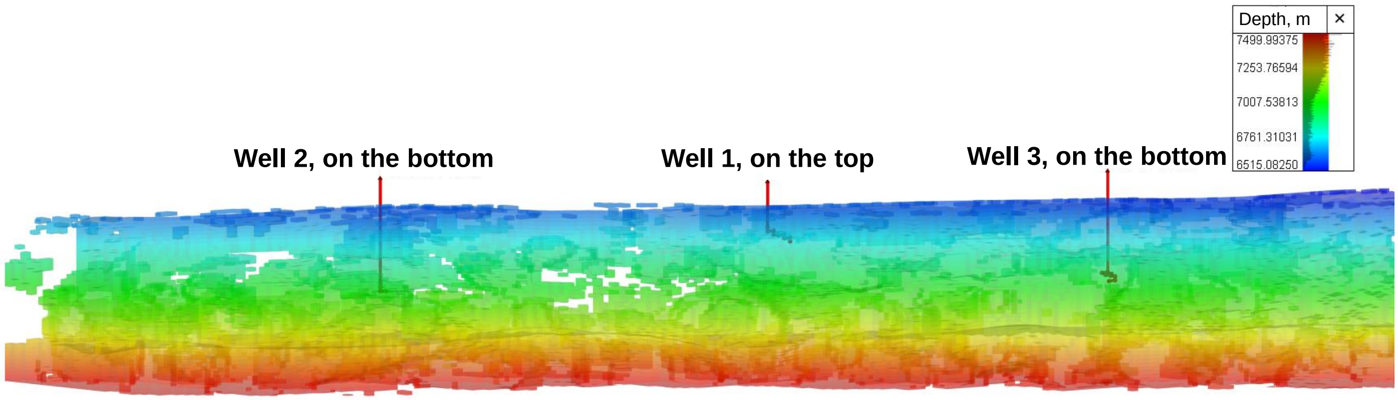


Fig. 3 Basic reservoir model

3. NUMERICAL SIMULATION

This study takes a well group in the Shunbei area as an example, and based on the phenomenon of gravity segregation in massive reservoirs and the mechanism of gas injection to suppress retrograde condensation, utilizes numerical simulation to conduct research on optimizing gas injection parameters for fissure-type carbonate rock gas condensate reservoirs. The research focuses on four aspects: gas injection location, timing, method, and rate. Initially, by enhancing the sweep efficiency of the injected gas, the optimal gas injection location is selected. Subsequently, considering the varying dew point pressures of different reservoir fluids and aiming to maximize the inhibition of retrograde condensation, the best gas injection timing is determined. Following this, by referencing on-site gas injection construction plans and using the ultimate condensate oil recovery as a benchmark, the optimal gas injection method is identified. Lastly, to stabilize the gas-oil two-phase interface and prevent gas channeling, the optimal gas injection rate is selected.

This study selected the well group in a typical fault zone in the Shunbei area, consisting of Well 1,Well 2 and Well 3, with a geological model schematic shown in Fig. 3. This well group commenced production in 2021, and currently, all three wells are being utilized as production wells for depletion. It is anticipated that by early 2024, the reservoir pressure of these wells will decrease close to the dew point pressure, consistent with the dew point pressure of 43.50 MPa obtained from well flow tests in Well 2. The overall depth of this reservoir section ranges from 6500 to 7400 meters, with an original pressure of 91 MPa, an original temperature of 158 °C, an average porosity of 3.7%, and an average permeability of 4.97 × 10^{-3} μm^2. Based on this data, a corresponding geological model was established as shown in Fig. 3, encompassing the Well 1, Well 2, and Well 3, with a total of 780,000 effective grid cells.

4. RESULTS

4.1 Gas injection locations

Based on different gas injection locations, three scenarios were established: depletion development, top gas injection development, and bottom gas injection development. The full depletion development serves as the control group, with a simulated production system depleting the entire well group until 2035, producing 350,000 cubic meters of gas per day. Well 2 was selected as the top gas injection well, with the other two wells then serving as production wells. Additionally, a bottom gas injection scenario was designed as a control group, with Well 1 chosen as the bottom gas injection well. Both the top gas injection and bottom gas injection scenarios followed the same production system: the well group is depleted until close to the dew point pressure, after which continuous gas injection commences for 84 months at a rate of 350,000 cubic meters per day, with a gas injection to production ratio of 1:1. In the late development stage, economic considerations lead to a transition to depletion development for 60 months.

Numerical simulations yielded the average reservoir pressure decline curves and cumulative gas production, as well as condensate oil recovery curves for the three scenarios, as shown in Fig. 4 and Fig. 5. Through a comprehensive analysis of the curves: in the full depletion development scenario, due to the lack of energy replenishment, once the pressure drops to the dew point pressure, significant condensate oil precipitation occurs within the reservoir, blocking normal gas flow pathways and leading to severe retrograde condensation phenomena. This results in the lowest cumulative gas production and cumulative oil production among the three scenarios. Simulation results indicate a final condensate oil recovery of only 24.7%.

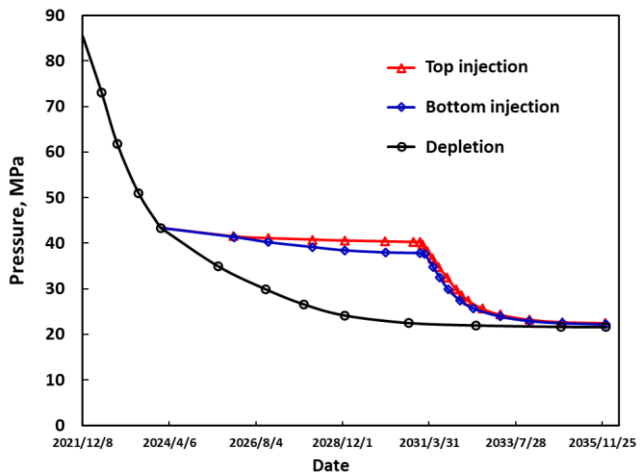


Fig. 4 Pressure during the depletion and gas injection

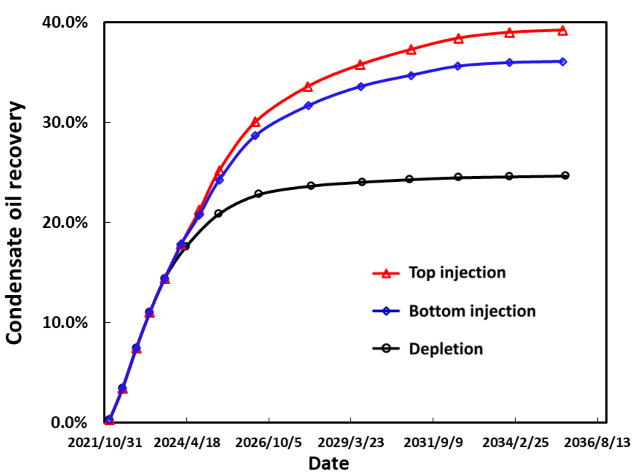


Fig. 5 Condensate oil recovery during the depletion and gas injection

Due to the same production system, the gas production rates in the top gas injection and bottom gas injection scenarios are roughly similar. However, compared to the bottom gas injection, the top gas injection scheme exhibits a higher condensate oil recovery of 3.1%, reaching 39.2%. CO_2 injected from Well 2 forms a gravity segregation from top to bottom. Under the control of the injected CO_2, the interface between these two zones stabilizes and moves downward, resulting in less condensate oil precipitation in the near-well area, maximizing the expansion of gas influence range, and effectively maintaining pressure to suppress retrograde condensation. In contrast, during bottom gas injection, CO_2 injected from Well 2 leads to early gas channeling due to factors such as density and gravity. This results in a smaller gas influence range, more condensate oil precipitation in the near-well area, poorer pressure maintenance effects, and ultimately a lower condensate oil recovery compared to the top gas injection method.

4.2 Gas injection timing

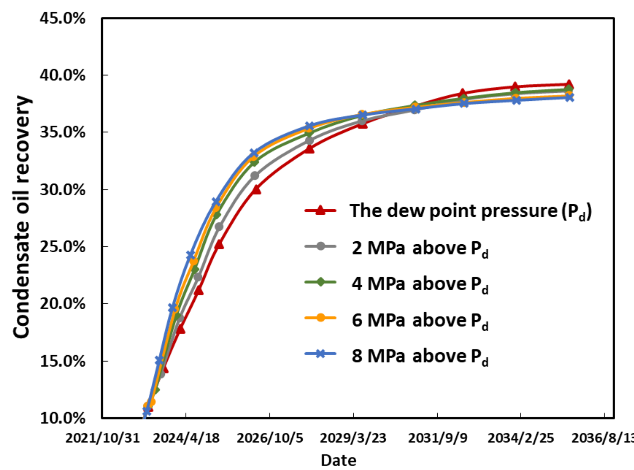


Fig. 6 Condensate oil recovery at different injection timing

This section analyzes the impact of different gas injection timing on the final condensate oil recovery. Building upon the top gas injection scheme, five gas injection scenarios were established based on dew point pressure, exceeding dew point pressure by 2 MPa, 4 MPa, 6 MPa, and 8 MPa, respectively. Simulation analysis was conducted to evaluate the effects of gas injection at different time points on the final condensate oil recovery and to determine the optimal gas injection timing. Simulation results are presented in Fig. 6.

The simulation results indicate that under the same production conditions, although earlier gas injection leads to higher condensate oil recovery and greater final gas production, injecting gas at the dew point pressure moment results in the highest condensate oil recovery. This is attributed to the occurrence of gas channeling and ineffective cycling when injecting gas while reservoir pressure is above the dew point pressure, which, in turn, reduces the condensate oil recovery.

4.3 Gas injection strategy

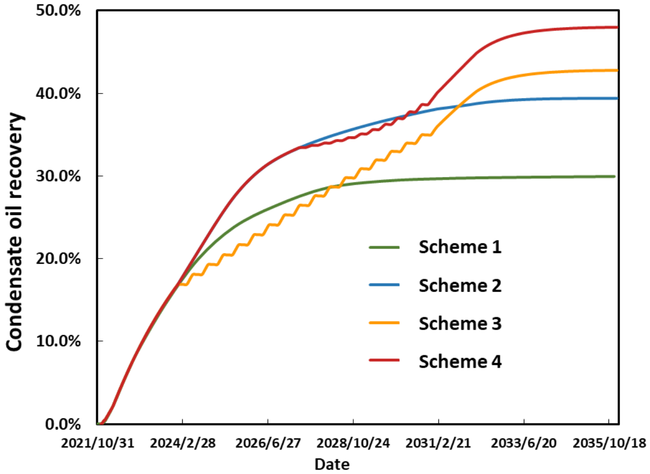


Fig. 7 Condensate oil recovery at different injection strategy

The simulation results indicate the following: Scheme 1, involving continuous gas injection, resulted in the lowest cumulative oil production and a final condensate oil recovery of 29.90%. This outcome was attributed to premature gas channeling, leading to an ineffective gas circulation post-injection. Scheme 2 employed a 'continuous gas injection + depletion development' strategy, which avoided the ineffective circulation formed by continuous gas injection in the later stages, achieving a final condensate oil recovery of 39.40%. Scheme 3 utilized a 'periodic gas injection + depletion development' approach, incorporating shut-in time to facilitate the extraction of heavy hydrocarbons by enabling gas and condensate gas to mix-phase extract. This strategy increased gas injection efficiency, resulting in a final condensate oil recovery of 42.75%. Scheme 4 adopted a 'continuous + periodic gas injection + depletion development' method. Early continuous gas injection maintained reservoir pressure consistently above the dew point pressure, while mid-term periodic gas injection enhanced gas injection efficiency. Late-stage depletion development prevented ineffective gas circulation, leading to a high condensate oil recovery of 47.93%. Consequently, Scheme 4 emerged as the optimal gas injection approach.

4.4 Gas injection rate

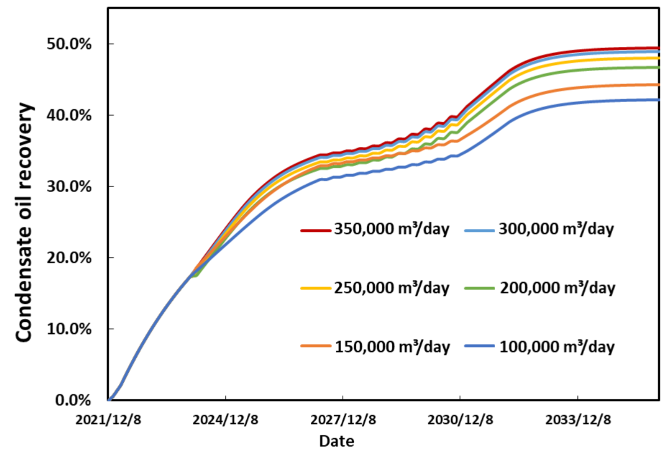


Fig. 8 Condensate oil recovery at different injection rate

Utilizing the dew point timing top gas injection method based on the 'continuous + periodic gas injection + depletion development' scheme, six different gas injection rates were set at 100,000 m^3/day, 150,000 m^3/day, 200,000 m^3/day, 250,000 m^3/day, 300,000 m^3/day, 350,000 m^3/day to simulate and analyze the impact of varying gas injection rates on the final condensate oil recovery.

The simulation results indicate that as the gas injection rate increases from 100,000 m^3/day to 200,000 m^3/day, there is a noticeable increase in both condensate oil and gas production, with a significant acceleration in the condensate oil recovery. However, as the gas injection rate further increases from 200,000 m^3/day to 350,000 m^3/day, the rate of increase in the condensate oil recovery diminishes. This trend suggests that the gas injection rate may be approaching a critical value where exceeding this threshold could lead to fingering and related phenomena. Optimal gas injection rates are crucial for ensuring the stability of displacement interfaces.

A Theory section should extend, not repeat, the background to the article already dealt with in the Introduction and lay the foundation for further work. In contrast, a calculation section represents a practical development from a theoretical basis.

5. DISCUSSION

This study focuses on a fractured-controlled fissure-cavity type condensate gas reservoir in the Shunbei area. A selection of typical wells already in production was made, and numerical simulation methods were employed. Leveraging the phenomenon of gravity segregation during development and based on the development mechanism of inhibiting retrograde condensation and enhancing the spreading coefficient through top gas injection, gas injection parameters were optimized through numerical simulation. Eventually, the optimal gas injection scheme applicable to the geological model conditions of the well group was identified.

Admittedly, limitations such as the insufficient precision of geological models in depicting actual underground reservoirs, simplifications in numerical simulation parameter settings, and the idealized nature of the gas injection scheme design may lead to variations between the predicted results of the gas injection scheme and actual field production outcomes. However, the trends and variations in gas injection development mechanisms and sensitivity analysis of parameters revealed by the numerical simulation results provide significant reference value for setting field construction parameters for gas injection and pressure maintenance in the development of fissure-cavity type condensate gas reservoirs in the Shunbei area.

6. CONCLUSIONS

1. Numerical simulation results indicate that the pressure maintenance production method involving top gas injection can suppress retrograde condensation, enhance the spreading coefficient of injected gas, and ultimately increase the condensate oil recovery.

2. Based on the geological model of the typical well group selected in this study, initiating gas injection when the pressure drops to the dew point pressure during the depletion is considered the optimal gas injection timing. Under this gas injection timing condition, the condensate oil recovery is maximized. Premature gas injection may lead to gas channeling, resulting in a decrease in condensate oil recovery.

3. Among the four gas injection methods designed in this study, the 'continuous gas injection in the early stage to maintain pressure, periodic gas injection in the mid-term, and depletion development in the later stage' method yields the best results with the highest condensate oil recovery. Employing continuous gas injection in the early stages helps maintain reservoir pressure above the dew point pressure consistently. Periodic gas injection in the mid-term aids in extracting heavy hydrocarbons and improving the efficiency of gas spreading. Depletion development in the late stage reduces gas injection costs and prevents excessive gas injection in later stages that could lead to ineffective cycling.

4. Based on simulation data from the WELL 3 well group, a daily gas injection rate of 350,000 m^3 is approximately the critical gas injection rate for this reservoir model. At this rate, the condensate oil recovery is highest, surpassing this critical rate may result in gas channeling or fingering phenomena. In actual gas condensate reservoir development, it is advisable to consider both economic feasibility and practicality of on-site construction plans to further optimize the best gas injection rate.

ACKNOWLEDGEMENT

This work was supported by the National Natural Science Foundation of China (52174041, 52104051, 52204058, and 51974356).

REFERENCE

[1] Yang, H. J., Chen, Y. Q., Tian, J., Du, J. H., Zhu, Y. F., Li, H. H., ... & An, H. T. (2020). Great discovery and its significance of ultra-deep oil and gas exploration in well Luntan-1 of the Tarim Basin. *China Petroleum Exploration*, 25(2), 62-72.

[2] Haiying, L. I., Jun, L. I. U., Wei, G. O. N. G., Chao, H., & Lidan, R. (2020). Identification and characterization of strike-slip faults and traps of fault-karst reservoir in the Shunbei area, Tarim Basin. *China Petroleum Exploration*, 25(3), 107.

[3] Yongsheng, M. A., Xunyu, C. A. I., Lu, Y. U. N., Zongjie, L. I., Huili, L. I., Shang, D., & Peirong, Z. (2022). Practice and theoretical and technical progress in exploration and development of Shunbei ultra-deep carbonate oil and gas field, Tarim Basin, NW China. *Petroleum Exploration and Development*, 49(1), 1-20.

[4] Liu, B., Qi, L., Li, Z., Liu, J., Huang, C., Yang, L., ... & Gong, W. (2020). Spatial characterization and quantitative description technology for ultra-deep fault-karst reservoirs in the Shunbei area. *Acta Petrolei Sinica*, 41(4), 412.

[5] Lixin, Q. I. (2020). Characteristics and inspiration of ultra-deep fault-karst reservoir in the Shunbei area of the Tarim Basin. *China Petroleum Exploration*, 25(1), 102.

[6] Li, S., Pan, Y., & Sun, L. (2011). Thoughts and suggestions for the improvement of the efficiency and development level of complex gas fields. *Nat. Gas Industry*, 31(12), 76-80.

[7] Wenjie, S., Tongwen, J., Jilei, F., Minglong, T., & Xiangjiao, X. (2005). Geological features and exploitation mechanism of the yaha condensate gas field in the tarim basin. *Chinese Journal of Geology*, 40(2), 274-283.

[8] Shi, Y., & Wang, G. (2002). Development and enhanced recovery techniques for condensate gas fields. *Natural Gas Industry*, 22(004), 108-109.

[9] Li, Y., Zhang, X., Wang, X., et al. (2000). Adjustment Measures of Circulating Gas Injection in Kekeya

Condensate Gas Field in Xinjiang Province and Its Development Effectiveness. *Natural Gas Industry*, (04), 61-62+4-3.
[10] LV Yanping, LUO Junlan, WANG Jong, et al. Development mode of typical carbonate fault–Affected Karst system in Tahe Oilfield[J]. *Journal of Xi'an Shiyou University (Natural Science Edition)*, 2021, 36(1): 20-27.
[11] WU Feng, DAI Jin, YAO Cong, et al. Developmental mode analysis of the fault-karst reservoir in Yijianfang Formation and Yingshan Formation of Ordovician in Tahe Oilfield[J]. *Fault-Block Oil & Gas Field*, 2022, 29(1): 33-39.
[12] Yanping, L. Ü., Junlan, L. U. O., Jiong, W. A. N. G., Juan, Z. H. A. N. G., Zhenzhe, Z. H. A. N. G., Hailong, M. A., & Xing, L. I. (2021). Development mode of typical carbonate fault-affected karst system in Tahe Oil - field. *Journal of Xi'an Shiyou University (Natural Science Edition)*, 36(1), 20-27.
[13] Chang, S., Zhuang, X., Deng, X., Yang, X., & Zhao, Z. (2017). Fault-karst carbonate reservoir prediction: a case study in Ordovician buried hills, HLHT Oilfield. *Oil Geophysical Prospecting*, 52(S1), 199-206.
[14] Rong, L., Mingyi, H., Renfang, P., & Zhonggui, H. (2019). Development characteristics and forming mechanism of Middle Permian fault-karst carbonate reservoirs in the central Sichuan Basin. *China Petroleum Exploration*, 24(1), 105.
[15] Morel, D. C., Nectoux, A., & Danquigny, J. (1997, October). Experimental Determination of the Mobility of Hydrocarbon Liquids during Gas Condensate Reservoir Depletion: Three Actual Cases. In *SPE Annual Technical Conference and Exhibition?* (pp. SPE-38922). SPE.
[16] Ali, J. K., Butler, S., Allen, L., & Wardle, P. (1993, September). The influence of interfacial tension on liquid mobility in gas condensate systems. In *SPE Offshore Europe Conference and Exhibition* (pp. SPE-26783). SPE.
[17] Zamehrian, M., & Sedaee, B. (2022). Underground hydrogen storage in a partially depleted gas condensate reservoir: influence of cushion gas. *Journal of Petroleum Science and Engineering*, 212, 110304.
[18] Zhang, A., Fan, Z., & Zhao, L. (2020). An investigation on phase behaviors and displacement mechanisms of gas injection in gas condensate reservoir. *Fuel*, 268, 117373.
[19] LIQian, Z. (2015). Proper gas injection time for the development of gas condensate reservoirs[J]. *Natural Gas Industry*, 35(10): 78-83.
[20] Sun, L. D., & Song, W. J. (2003). Gas recycling project of Yaha condensate gas field in Tarim Basin. *Petroleum Exploration and Development*, 30(5), 101-103.
[21] Huaming, S. O. N. G., Shuyang, C. H. E. N., ZHANG, Y., Guojun, Z. H. A. N. G., & Yanhua, J. I. N. (2010). Study on cyclic gas injection technology for development of Dalaoba condensate field in Tarim basin. *Oil Drilling & Production Technology*, 32(11), 120-123.
[22] Jiang, T., Sun, L., Xie, W., Xiao, X., Wang, Y., & Xia, J. (2021). Three-element development mechanism of cyclic gas injection in condensate gas reservoirs and a new technique of enhancing condensate oil recovery. *Acta Petrolei Sinica*, 42(12), 1654.
[23] Zhang, L., Xie, W., Yang, J., Tumeng, G. L., & Yang, S. Y. (2016). Gravity segregation of the cyclic gas injection in the condensate gas reservoirs in the middle and late development stages. *Petroleum Geology and Oilfield Development in Daqing*, 35(1), 120-125.
[24] Shuxian, L. I. A. N. G., Wei, Z. H. O. U., & Jiandong, Z. H. A. N. G. (2014). Investigation on effect application of the technology of crestal gas injection for stable gravity flooding. *Journal of Southwest Petroleum University (Science & Technology Edition)*, 36(4), 86-92.
[25] Wei, Z. H. O. U., Jiandong, Z. H. A. N. G., & Yongliang, T. A. N. G. (2017). Application of top gas injection-assisted gravity drainage in bottom water reservoirs. *Journal of Southwest Petroleum University (Science & Technology Edition)*, 39(6), 92-100.
[26] Guo, P. (2001). Study on the phase-state restorarion of gas condensate reservoirs. *JOURNAL-SOUTHWEST PETROLEUM INSTITUTE*, 23(2), 25-29.
[27] Hou, D., Gao, L., Liu, H., Zhang, M., & Cui, F. (2013). Dynamic phase behavior of near-critical condensate gas reservoir fluid. *Natural Gas Industry*, 33(11), 68-73.
[28] Li-ming, Z. H. A. N. G., Xiao-qiang, W. A. N. G., Da-li, H. O. U., Ke, X. I. A. O., Chen-guang, J. I. A. N. G., & Xiao-mei, Z. O. U. (2020). Phase behavior characteristics of near-critical oil and gas reservoirs in Tarim Basin. *Natural Gas Geoscience*, 31(3).
[29] Zhu, Z. Q. (2015). Mechanism and phase behavior of retrograde condensation inhibition by secondary gas injection in the Yaha condensate gas reservoir. *Natural Gas Industry*, 35(5), 60-65.
[30] He, X., Huang, Z., Lian, L., et al. (2023). Key technologies for enhancing the recovery of condensate gas reservoirs by gas injection-storage coordination. *Natural Gas Industry*, 43(1), 86-95.
[31] Zhao, F., Song, L., Feng, H., et al. (2021). Experimental study of CO2 gravity segregation effected by oil density in thick sandstone reservoirs. *Fault-Block Oil & Gas Field*, 28(6), 842-847.
[32] Lu, T., Li, Z., Gu, Z., & Du, L. (2023). Stability and enhanced oil recovery performance of CO2 in water emulsion: Experimental and molecular dynamic simulation study. *Chemical Engineering Journal*, 464, 142636.

[33] Rezk, M. G., Ibrahim, A. F., & Adebayo, A. R. (2023). Uncertainty quantification for CO2 storage during intermittent CO2-EOR in oil reservoirs. *International Journal of Coal Geology*, 266, 104177.
[34] Iddphonce, R., Wang, J., & Zhao, L. (2020). Review of CO2 injection techniques for enhanced shale gas recovery: Prospect and challenges. Journal of Natural Gas Science and Engineering, 77, 103240.
[35] Bai, M., Sun, J., Song, K., Li, L., & Qiao, Z. (2015). Well completion and integrity evaluation for CO2 injection wells. Renewable and Sustainable Energy Reviews, 45, 556-564.
[36] Zhang, P. Y., Huang, S., Sayegh, S., & Zhou, X. L. (2004, April). Effect of CO2 impurities on gas-injection EOR processes. In SPE Improved Oil Recovery Conference? (pp. SPE-89477). SPE.
[37] Jia, B., Tsau, J. S., & Barati, R. (2019). A review of the current progress of CO2 injection EOR and carbon storage in shale oil reservoirs. Fuel, 236, 404-427.
[38] Zhou, X., Liang, D., Liang, S., Yi, L., & Lin, F. (2015). Recovering CH4 from natural gas hydrates with the injection of CO2–N2 gas mixtures. Energy & fuels, 29(2), 1099-1106.
[39] Bai, G., Su, J., Zhang, Z., Lan, A., Zhou, X., Gao, F., & Zhou, J. (2022). Effect of CO2 injection on CH4 desorption rate in poor permeability coal seams: An experimental study. Energy, 238, 121674.