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NUMERICAL MODELING AND COMPARATIVE ANALYSIS OF STRATEGIES FOR ENHANCING OIL RECOVERY AND GEOLOGICAL STORAGE OF CO_2 IN A DEPLETED OIL RESERVOIR

The object of the study is the processes of enhancing oil recovery and geological storage of CO_2 in a depleted, highly waterflooded oil reservoir, modeled using a three-dimensional compositional reservoir simulation model.

The key problem addressed in CCUS projects is the internal contradiction between maximizing oil production and optimizing the volume and safety of long-term CO_2 storage. The study examined the choice of an operational strategy that would balance these objectives under conditions of high geological heterogeneity and the risk of early gas breakthrough.

It was established that the "injection – depletion" strategy provides the highest cumulative oil production (about 1.8 million m^3) but is inefficient due to early gas breakthrough (after ~ 2 years). The pressure-maintenance strategy proved to be the most balanced: gas breakthrough was delayed by 1.5 years, ensuring high CO_2 storage efficiency, but cumulative oil production was lower (about 1.5 million m^3). The water-alternating-gas (WAG) technology, for the geological conditions of this reservoir, proved detrimental, causing abnormal pressure build-up (up to 824 bar) and blockage of oil reserves.

The obtained results are explained by the physics of the process. The early gas breakthrough in the first scenario is due to CO_2 gravitational segregation and the formation of a gravity override ("gravity tongue"). The efficiency of the second scenario is associated with the creation of a more stable displacement front through pressure maintenance. The complete inefficiency of WAG is explained by the presence of high-permeability channels in the geologically heterogeneous formation, through which water moved, bypassing the oil.

The results can be practically applied by operators of mature fields to justify the choice of a CCUS strategy. They provide a quantitative basis for assessing the trade-off between short-term economic benefits (production) and long-term environmental objectives (storage). The study confirms the critical importance of conducting detailed geological modeling before applying WAG, in order to avoid substantial financial losses.

Keywords: *enhanced oil recovery, geological storage of CO_2, CCUS, numerical modeling, WAG, optimization, geological heterogeneity.*

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1. Introduction

The world faces a dual challenge: meeting the growing global demand for energy while simultaneously mitigating the effects of anthropogenic climate change. In this context, carbon capture, utilization, and storage (CCUS) technologies are recognized as a critically important tool for decarbonizing hard-to-abate industrial sectors such as power generation, cement, and steel production [1]. Among the various CCUS approaches, CO_2-based enhanced oil recovery (CO_2-EOR) stands out as a mature technology offering an economically attractive pathway to initiate large-scale geological storage projects. Revenue from the production of additional oil can partially or fully offset the high costs of CO_2 capture, transportation, and injection [2].

Potential of depleted oil and gas fields: Depleted oil and gas fields are prime candidates for CCUS projects. Their advantages are evident: proven capability to retain hydrocarbons over geological timescales, well-characterized geological structures, and the presence of existing infrastructure, which significantly reduces capital costs [3]. Late-stage fields are often characterized by high water cut and substantial remaining oil reserves, which can reach 60% or more of the original oil in place [4]. This creates a strong incentive to apply tertiary enhanced oil recovery methods, among which CO_2 flooding is one of the most effective.

Challenges process optimization and geomechanical risks: The main challenge lies in the fundamental trade-off between maximizing oil production and optimizing the volume and safety of long-term CO_2 storage. Operational strategies that are optimal for one objective are not always optimal for the other [5]. For example, high injection rates may accelerate production but cause early gas breakthrough and reduce sweep efficiency, which negatively impacts both ultimate oil recovery and the volume of CO_2 stored [6].

Long-term storage integrity is an absolute requirement and is governed by complex geomechanical processes triggered by fluid injection [7]. Injecting large volumes of CO_2 alters reservoir pressure and temperature, inducing changes in the stress – strain state of the

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rock. This can lead to caprock integrity loss, reactivation of pre-existing faults, and, as a result, the creation of potential leakage pathways for CO_2 [8]. Therefore, simple reservoir simulation is insufficient for reliable assessment; coupled hydrodynamic – geomechanical analysis is necessary [9].

At the same time, the existing scientific literature lacks a comprehensive comparative analysis that quantitatively evaluates the trade-off between maximizing oil recovery and ensuring the safety of long-term CO_2 storage for various operational scenarios under high geological heterogeneity.

The aim of this study is to identify and quantitatively assess the impact of different CO_2 injection strategies on oil production dynamics and the efficiency of geological carbon storage in a depleted, geologically heterogeneous reservoir. This objective is achieved through a comparative analysis of numerical models for "injection – depletion", simultaneous pressure maintenance, and water-alternating-gas (WAG) strategies, with the goal of identifying the key physical mechanisms that determine project success. The results are intended to provide practical, quantitatively grounded recommendations for field operators on selecting an optimal strategy that balances short-term economic benefits from enhanced oil recovery with long-term environmental goals of safe CO_2 storage.

2. Materials and Methods

The object of this study is the processes of enhanced oil recovery (EOR) and geological storage of CO_2 in a depleted, highly waterflooded oil reservoir, modeled using a three-dimensional compositional reservoir simulation model.

The investigation of enhanced oil recovery and CO_2 geological storage processes was conducted through numerical simulation based on a 3D compositional reservoir model of a section of a depleted oil field. Simulations were carried out using the tNavigator software package (Rock Flow Dynamics, USA), which allowed for an accurate reproduction of multiphase fluid flow, the chemical interaction of CO_2 with reservoir fluids, and the dynamics of pressure and saturation fields.

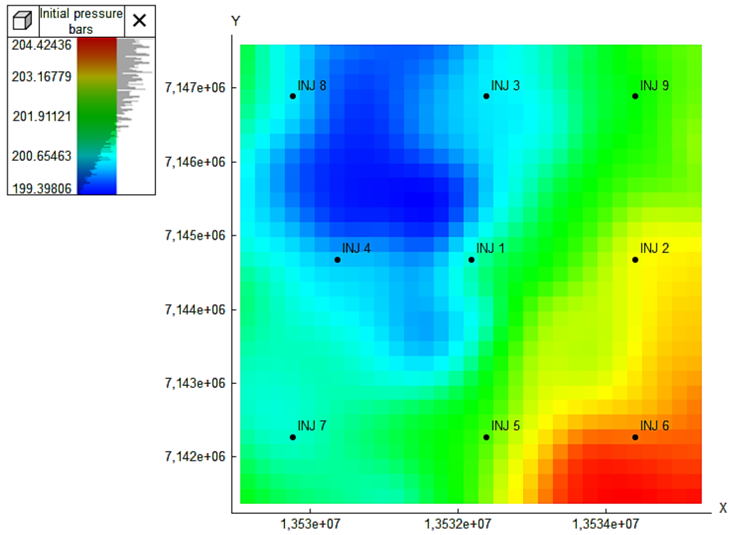

Fig. 1. Pressure distribution map in the model and well configuration

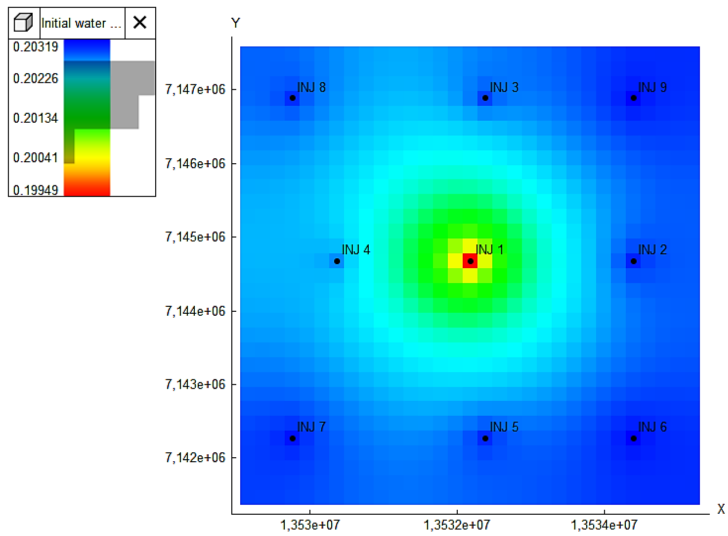

Fig. 2. Water saturation distribution in the model

A three-dimensional reservoir model of the study area, characterized by significant geological heterogeneity, was used. The well placement and the initial pressure distribution map are shown in Fig. 1.

The reservoir's petrophysical properties are spatially heterogeneous. The net-to-gross ratio varies from 0.01 to 1, with an average value of 0.856, indicating the presence of non-productive zones within the model area. Porosity is also unevenly distributed, ranging from 0.01% to 38.95%, with an average of 28.08%.

Permeability is anisotropic overall. In the horizontal plane, it is isotropic (average PermX and PermY are 371.43 mD), whereas vertical permeability (PermZ) is significantly lower, with an average value of 82.30 mD. This ratio ($kH/kV \approx 4.5$) is typical for terrigenous reservoirs.

Initial conditions and fluid properties. The model reproduces the reservoir state at the end of the previous development stage. The initial reservoir pressure in the model ranges from 199.39 to 210.76 bar (average 204.28 bar). The initial bubble-point pressure is 35 bar. Since the reservoir pressure substantially exceeds the bubble-point pressure, the reservoir at the initial moment is highly undersaturated, with no free gas present.

Current water saturation is highly uneven – from 0.199 to 1.0, with a high average value of 0.5239. This distribution is a direct consequence of the previous development history, in particular, the implementation of a waterflooding system in the final stage, which led to significant water encroachment. The water saturation distribution map is shown in Fig. 2.

The PVT properties of the formation water, including the dependence of CO_2 solubility on pressure, a key mechanism of its storage, are presented in Fig. 3.

Relative permeability curves for the "water – oil" system and capillary pressure are shown in Fig. 4. According to the graph, the residual oil saturation (Sor) is about 0.45, while the irreducible water saturation (Swi) is about 0.2.

Simulation scenarios: to evaluate the effectiveness of CO_2-EOR and geological CO_2 storage, several scenarios were developed, incorporating different CO_2 injection strategies. Each scenario involved a specified CO_2 injection period followed by monitoring of the reservoir and fluid behavior.

The main parameters of the scenarios included:

1. *Injection duration:* injection periods ranging from X to Y years were investigated to assess the long-term impact.

2. *Injection modes:* both continuous CO_2 injection and cyclic injection in a water-alternating-gas (WAG) mode with varying water-to-CO_2 volume ratios were considered. The WAG mode is of particular interest for improving sweep efficiency and reducing gas breakthrough.

3. *Injection rate:* CO_2 injection rates were varied to analyze their influence on reservoir pressure, displacement front behavior, and production rates.

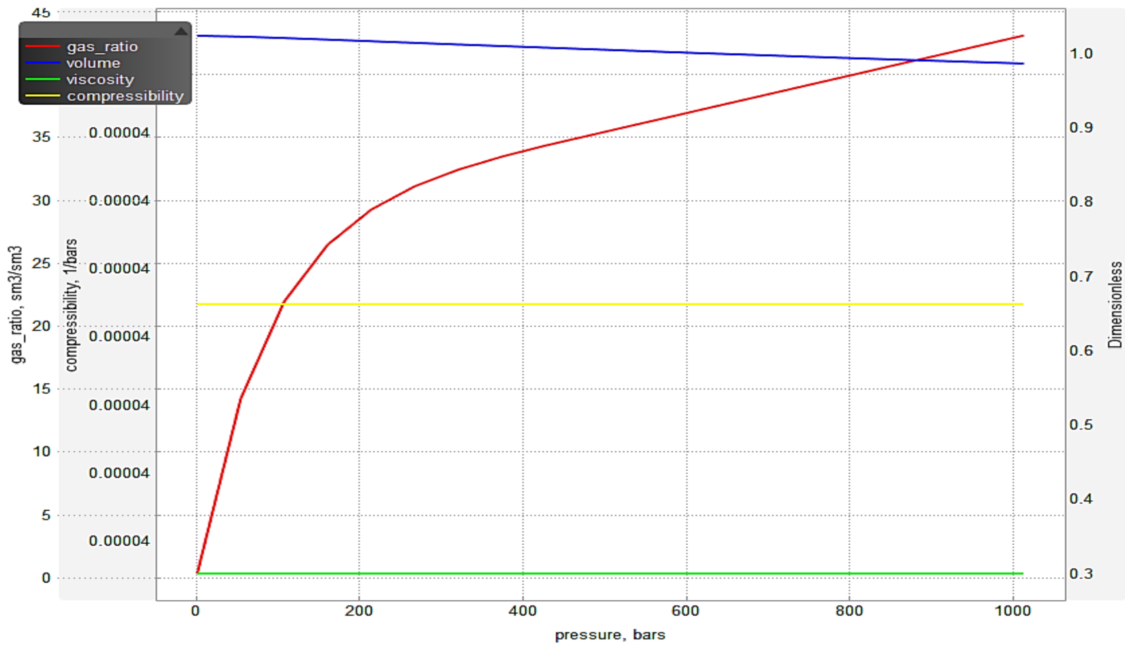

Fig. 3. PVT properties of the "water – gas" system: dependence of CO_2 solubility, formation volume factor, viscosity, and compressibility of water on pressure

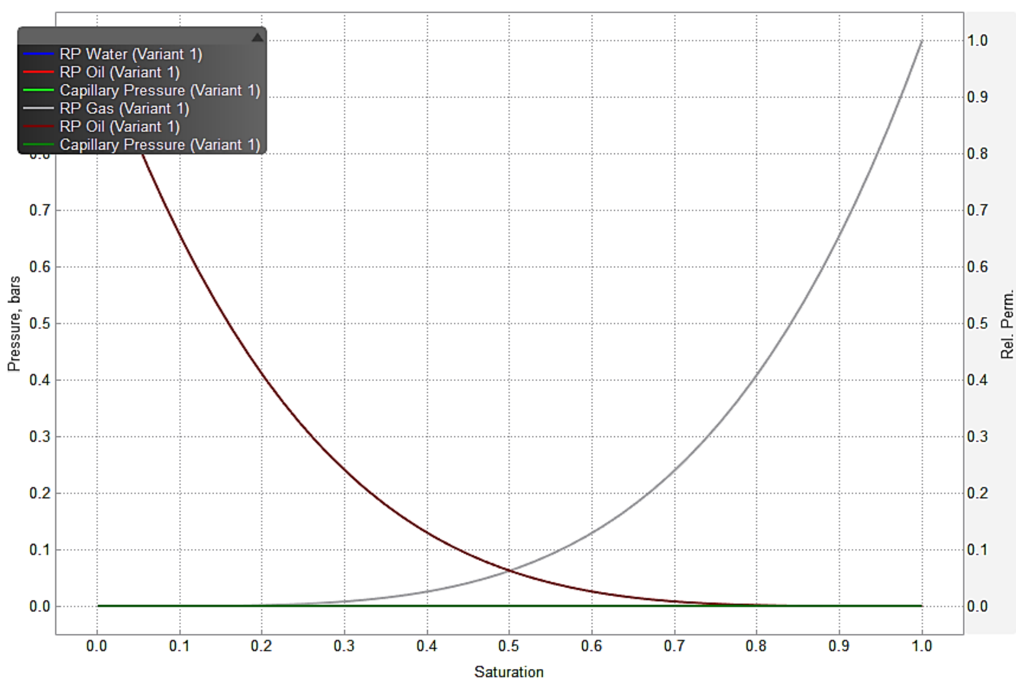

Fig. 4. Relative permeability curves for the "water – oil" system and capillary pressure

3. Results and Discussion

3.1. Physical-chemical mechanisms of CO_2-EOR and sequestration

Miscible and immiscible displacement: The efficiency of the CO_2-EOR process largely depends on the interaction between the injected CO_2 and the reservoir oil. These interactions can be classified into two main modes:

Miscible displacement: This mode is achieved when reservoir pressure exceeds the so-called minimum miscibility pressure (MMP). MMP is the critical threshold at which CO_2 and oil become fully soluble in each other, forming a single phase. This leads to the disappearance of interfacial tension, which is the main capillary barrier retaining oil in the pores. Miscibility can be achieved in two ways: at first contact, if fluid properties and reservoir conditions are favorable, or through a multiple-contact mechanism (vaporizing or condensing gas drive), where CO_2 is gradually enriched with light oil components or vice versa [10]. The main advantages of the miscible mode are significant oil swelling (increased volume) and a sharp decrease in viscosity, which substantially improves oil mobility and the efficiency of its displacement toward production wells [11].

Immiscible displacement: This process occurs at pressures below the MMP. Although it is less efficient than miscible flooding, it still provides certain benefits. CO_2 partially dissolves in the oil, causing it to swell and reducing its viscosity, while also maintaining reservoir pressure, which slows the decline in production rates. This mode is often the only viable option for shallow reservoirs or in cases where caprock integrity limits the maximum allowable injection pressure.

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Mobility control: One of the key problems in gas flooding is the significant viscosity contrast between CO_2 (which is highly mobile) and oil and water. This unfavorable mobility ratio leads to the phenomenon known as viscous fingering (Fig. 5), when gas breaks through the oil bank along the paths of least resistance, leaving significant oil volumes unswept [12].

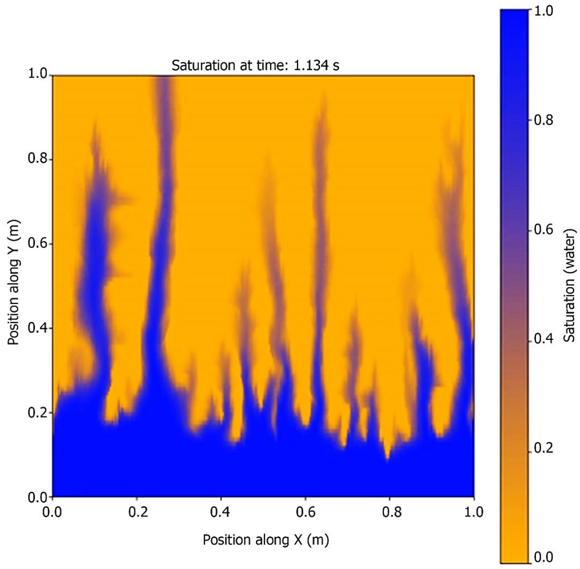

Fig. 5. Schematic illustration of the "viscous fingering" phenomenon

To counter this phenomenon and improve sweep efficiency, the water – alternating – gas (WAG) technology is applied. Water, having higher viscosity, helps stabilize the displacement front and push CO_2 into less permeable zones of the reservoir. More advanced methods are also being developed, such as the use of foams or polymer gels to increase the viscosity of the injected agent.

CO_2 trapping mechanisms: Long-term and safe storage of CO_2 in geological formations is ensured by a combination of four main mechanisms operating over different timescales:

1. *Structural/stratigraphic trapping*: This is the fastest and initial mechanism, analogous to the natural formation of oil and gas accumulations. CO_2 in the free phase (as gas or supercritical fluid) rises due to its lower density and is trapped beneath an impermeable rock – the caprock (e. g., tight shales or evaporites). The integrity of this caprock is critically important for the initial safety of the storage.
2. *Residual (capillary) trapping*: As the CO_2 plume migrates through the porous reservoir, part of the gas remains behind as immobile, disconnected bubbles retained by capillary forces in the rock pores. This mechanism acts quickly and can provide a significant part of the total storage capacity.
3. *Solubility trapping*: CO_2 dissolves in formation water (brine) present in the reservoir pores. The resulting CO_2-water solution is slightly denser than ordinary formation water, so it slowly sinks, which significantly reduces the risk of upward leakage. This process lasts from decades to centuries and increases storage security over time.
4. *Mineral trapping*: This is the slowest but also the most reliable storage mechanism. CO_2 dissolved in water forms weak carbonic acid, which reacts with the minerals of the host rocks to form new, stable carbonate minerals (e. g., calcite, dolomite, siderite). This process, lasting thousands of years, effectively converts CO_2 into part of the rock, ensuring its permanent immobilization [12].

3.2. Base simulation scenario

The base scenario models a strategy consisting of two main stages: a prolonged period of CO_2 injection to increase reservoir pressure and create conditions for oil displacement, followed by a transition to a depletion stage. This approach is often considered one of the fundamental CO_2-EOR strategies.

The modeling strategy for the base case involved the use of the existing well pattern, consisting of one central production well (PROD 1) and eight peripheral injection wells (INJ 2–INJ 9). In the first stage, lasting 18.5 years (from 2000 to June 2018), CO_2 was continuously injected into all injection wells at a total daily rate of 1500 thousand m^3/day, with a maximum bottomhole pressure limit of 500 bar. During this period, the production well PROD 1 remained shut in. In the second stage, from June 2018 to January 2024, CO_2 injection was completely stopped and the production well PROD 1 was brought on stream. Its operation was controlled by a minimum bottomhole pressure set at 70 bar.

In the first stage (2000–2018), there was an intensive increase in average reservoir pressure from the initial ~204 bar to a peak value exceeding 410 bar. This indicates successful energy accumulation in the reservoir and the creation of pressure significantly higher than the initial value. After the production well was put into operation in mid-2018, a sharp pressure decline began as a result of depletion drive. By the end of the calculation period (January 2024), the average pressure had dropped to ~ 106 bar (Fig. 6).

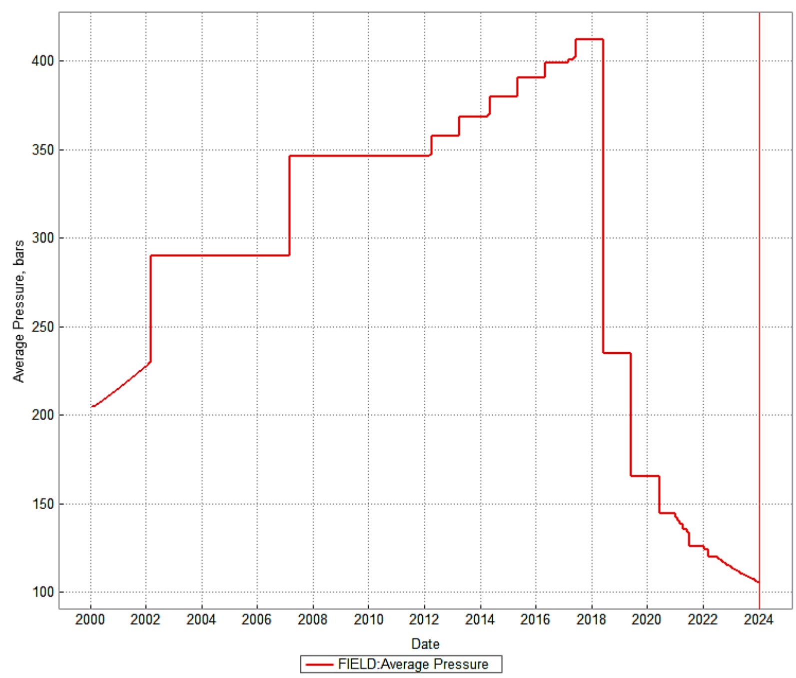

Fig. 6. Dynamics of average reservoir pressure in the base scenario

Analysis of daily and cumulative production data shows a characteristic trend for this method. The oil rate reaches a maximum of about 1500 m^3/day immediately after the well is started, after which it steadily declines to ~ 800 m^3/day by the end of the period. At the same time, the scenario is characterized by an extremely high initial water production. The water cut at start-up is about 96%, which is a direct consequence of the high initial water saturation of the reservoir. It is important to note the positive trend of a slow decrease in water cut to ~90% by the end of the period, which may indicate more efficient mobilization of residual oil by expanding CO_2 compared to water. A critical aspect is gas breakthrough to the production well, which occurs about two years after the start of production (mid-2020). From this point, gas rate and gas-oil ratio (GOR) begin to rise sharply, indicating the formation of a direct flow channel between the injection front and the production well (Fig. 7).

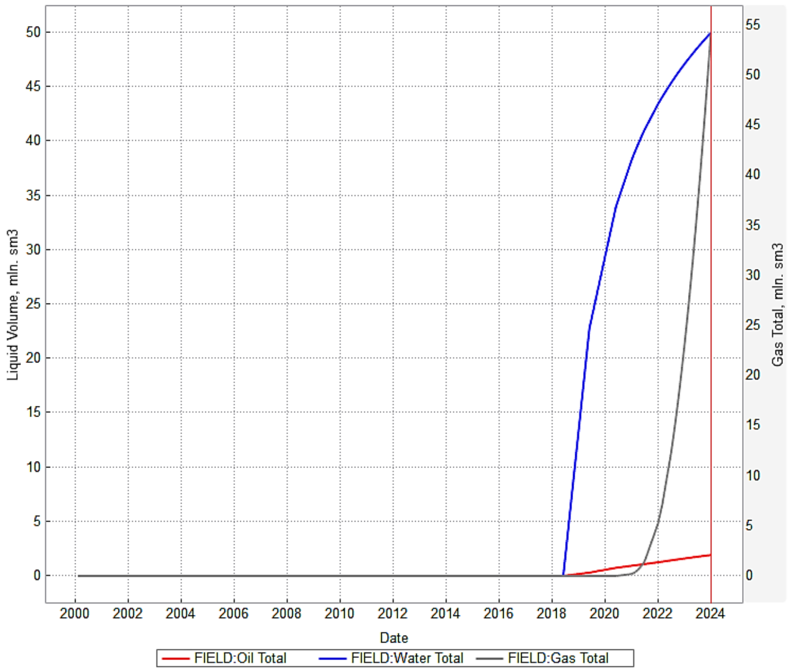

Fig. 7. Dynamics of cumulative fluid production

Thus, the base scenario of continuous CO_2 injection followed by depletion demonstrates the ability of the technology to mobilize residual oil even in a highly waterflooded reservoir. However, it also reveals significant drawbacks, the main ones being early gas breakthrough, which reduces sweep efficiency, and persistently high water cut. Rapid CO_2 breakthrough leads to inefficient loss of reservoir energy and the need to handle large volumes of produced gas.

Spatial visualization of gas saturation distribution at the end of the calculation period (Fig. 8) clearly illustrates these processes. The reservoir section shows the formation of a high-conductivity channel, known as "gravity tongue", in the upper part of the reservoir. Along this channel, light CO_2 migrates from peripheral injection wells to the central production well due to gravitational segregation. This visually confirms the mechanism of early gas breakthrough and explains the rapid increase in gas-oil ratio observed in the graphs. At the same time, it clearly demonstrates the low sweep efficiency, as significant reservoir volumes, especially in its lower parts, remain practically unaffected by the displacement process.

On the other hand, from the point of view of geological storage, this same visualization confirms the high efficiency of CO_2 retention. The main volume of the injected carbon dioxide forms a stable gas cap in the crest of the structure, which indicates the reliability of the structural trapping mechanism. Analysis of cumulative indicators (Fig. 7) also shows that the volume of produced CO_2 is negligible compared to the total injected volume. The main storage mechanisms are structural/stratigraphic trapping and dissolution in large volumes of formation water.

3.3. CO_2 injection with pressure maintenance

In the second scenario, an alternative strategy was examined, aimed at improving displacement front control and delaying gas breakthrough. Unlike the base "injection – depletion" mode, this case simulated simultaneous production and injection to maintain reservoir pressure (pressure maintenance).

The modeling strategy also consisted of two stages. In the first stage (2000–June 2018), CO_2 was injected into the injection wells at a total daily rate of 1,000,000 m^3/day, which is one-third lower than in the base scenario.

The production well PROD 1 remained shut in. In the second stage (June 2018–January 2024), the well PROD 1 was put into operation, and CO_2 injection continued but at half the previous rate – 500,000 m^3/day. The operating parameters of the production well and the injection pressure limits were the same as in the base scenario.

The change in injection strategy had a significant impact on development dynamics, as clearly shown by the comparative graph of average reservoir pressure for both scenarios (Fig. 9). Due to the smaller amount of injected gas in the first stage, the peak pressure in Scenario 2 (green line) reached only ~350 bar, which is considerably lower than the 410 bar in the base case (red line). However, after the start of production, due to continued injection, the pressure decline was much slower and more controlled, indicating effective maintenance of reservoir energy.

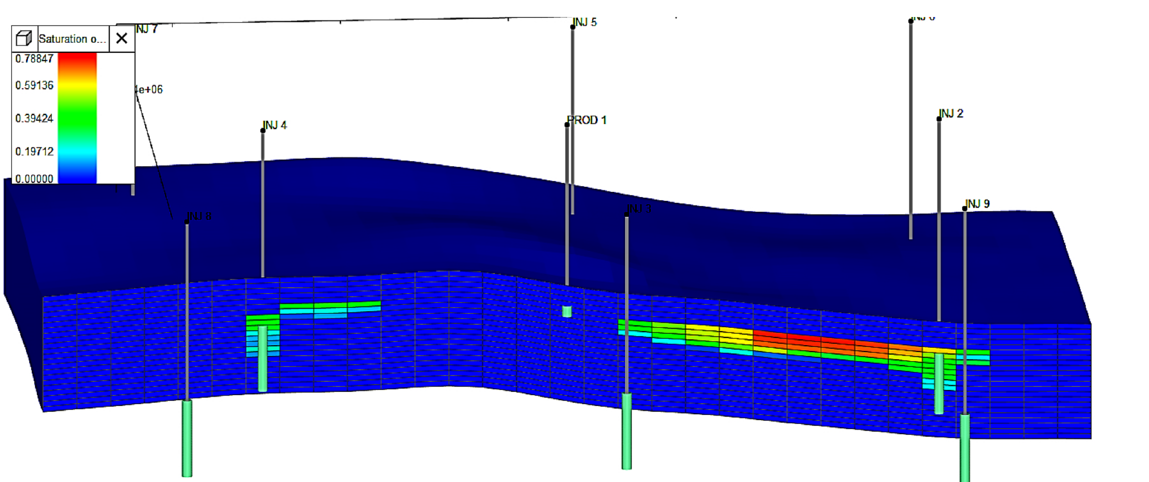

Fig. 8. Gas saturation (Sg) distribution in the reservoir at the end of the base scenario simulation (3D view and cross section)

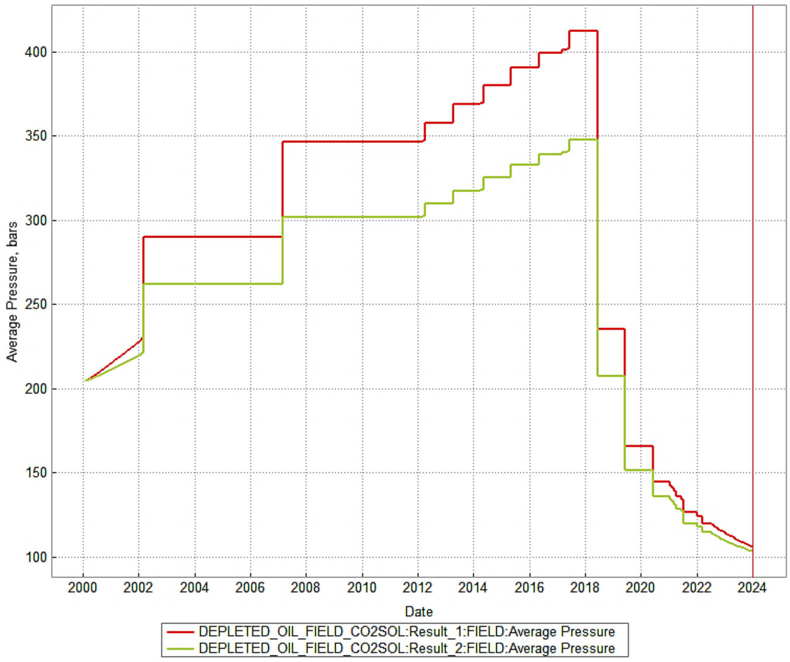

Fig. 9. Comparison of average reservoir pressure dynamics for the base scenario (Result 1) and Scenario 2 (Result 2)

Analysis of other performance indicators shows that the initial oil rate was slightly lower than in the base case, at about 1250 m^3/day, which is a consequence of the lower initial pressure. The most important result is the significantly later gas breakthrough. While in the base scenario CO_2 appeared in the well's production stream as early as mid-2020, in this scenario the breakthrough was recorded only at the beginning of 2022 – 1.5 years later. This indicates a more stable displacement front and better control of CO_2 mobility.

The pressure-maintenance strategy through simultaneous injection and production demonstrated significant advantages in managing the EOR process. The main positive effect is the substantial delay in gas breakthrough, which allows the injected CO_2 to work more effectively in the reservoir, potentially improving sweep efficiency.

From the perspective of geological carbon storage, this scenario is much more effective. Due to the later breakthrough and lower gas-oil ratio, the volume of produced CO_2 by the end of the period was minimal, meaning that the vast majority of injected gas remained securely stored in the reservoir.

However, this strategy also has a drawback: the cumulative oil production by the end of the calculation period (about 1.5 million m^3) was lower than in the base scenario (about 1.8 million m^3). The aggressive depletion mode in the first case allowed for a greater volume of oil to be recovered over the same period, albeit with lower process efficiency.

3.4. Analysis of the impracticality of applying WAG

The third scenario examined the effectiveness of the water – alternating – gas (WAG) technology with annual cycles. The simulation results showed that, for the conditions of this reservoir and the selected parameters, this strategy is not only impractical but even detrimental. The use of WAG led to an abnormal increase in reservoir pressure to 824 bar, which is almost twice the peak values observed in other scenarios and caused the premature shutdown of most injection wells due to exceeding pressure limits.

Further analysis showed that the injected water likely formed direct high-permeability flow channels to the production wells, moving through zones with the best filtration properties. As a result, the main oil volumes concentrated in less permeable areas were completely bypassed by the displacement front. Consequently, after transitioning to the production stage, the producing wells began to deliver almost 100% water, without yielding commercial oil volumes. Thus, instead of improving reservoir sweep – the main objective of the WAG technology – cyclic injection in this configuration only exacerbated the negative effects of geological heterogeneity. The strategy effectively led to the blockage of residual oil reserves by water, making their further efficient recovery impossible. This demonstrates the critical importance of carefully selecting WAG parameters – such as cycle duration and agent volumes – with regard to the specific geological structure of the reservoir.

3.5. Limitations of the study and prospects for its development

It is important to recognize that this study has certain limitations that define the scope of applicability of the conclusions. First, the modeling did not include coupled geomechanical analysis. Changes in reservoir pressure, especially significant increases, can induce stress-strain responses in the rock, potentially leading to caprock integrity impairment; therefore, the long-term safety of CO_2 storage requires further assessment. Second, the work is focused on technical aspects and does not include a techno-economic model that would allow evaluating the profitability of each strategy for making a final investment decision. The results were also obtained for a specific geological model, and although the identified patterns have a general physical nature, their quantitative manifestation may differ significantly for reservoirs with other properties.

The study was carried out under martial law in Ukraine. This created objective challenges, in particular limiting opportunities for international scientific communication and access to some computational resources. At the same time, these conditions significantly increased the relevance of this work. In the context of Ukraine's critical need to achieve energy independence, the search for ways to increase production from domestic, often depleted, fields has become a matter of strategic importance. Thus, martial law became a strong motivator for finding effective engineering solutions for the national oil and gas industry.

Based on the obtained results and identified limitations, further research may focus on integrated hydrodynamic – geomechanical modeling for comprehensive assessment of CO_2 leakage risks. Another promising direction is the development of a techno-economic model to determine not only the technically but also the economically optimal development option. The study of alternative CO_2 mobility control methods, such as foam or polymer application, may prove effective under conditions of high geological heterogeneity. Finally, sensitivity analysis and optimization will make it possible to determine how changes in key parameters affect the final production and storage performance.

4. Conclusions

The numerical study demonstrates the key trade-offs between enhanced oil recovery and geological CO_2 storage. The "injection – depletion" strategy, although providing the highest cumulative oil production of about 1.8 million m^3, proved inefficient in terms of utilization of the injected agent. This outcome is explained by the rapid gas breakthrough to the production well, which occurred just two years after the start of production. The cause was gravitational segregation, where the light CO_2 formed "gravity tongue" in the upper part of the reservoir, bypassing significant oil volumes. The practical value of this finding lies in showing that an aggressive approach focused solely on maximizing production leads to inefficient CO_2 use and leaves substantial reserves in the reservoir.

In contrast, the pressure-maintenance strategy proved to be a much more balanced and controlled solution. It delayed gas breakthrough by 1.5 years compared to the base scenario and ensured high CO_2 storage efficiency with minimal return to the surface. This was achieved through the formation of a more stable displacement front. The trade-off for this control was a somewhat lower cumulative oil production, about 1.5 million m^3. This result has important practical significance, as it quantitatively illustrates the fundamental CCUS project dilemma: reliable geological storage is achieved at the expense of reduced production rates, enabling operators to make informed decisions that balance economic and environmental objectives.

At the same time, the study found that the water – alternating – gas (WAG) technology, under the conditions of this reservoir, is not only impractical but detrimental. Its application led to an abnormal increase in reservoir pressure to 824 bar and to the production of nearly 100% water. This is explained by high geological heterogeneity, which caused the injected water to flow through existing high-permeability channels, completely bypassing and blocking residual oil reserves. This conclusion is a critical warning, demonstrating that standard technologies are not universal and that their success requires detailed preliminary modeling that takes into account the specific geology of the reservoir.

Conflict of interest

The authors declare that they have no conflict of interest regarding this study, including financial, personal, authorship-related, or other factors that could have influenced the research and its results presented in this article.

Financing

The study was conducted without financial support.

Data availability

The manuscript has associated data in a data repository.

Use of artificial intelligence

The authors confirm that no artificial intelligence technologies were used in the preparation of this work.

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