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STUDY OF PHYSICOCHEMICAL AND GEOCHEMICAL ASPECTS OF ENHANCED OIL RECOVERY AND CO_2 STORAGE IN OIL RESERVOIRS

The object of research is the processes of multiphase filtration in porous media. These processes occur when carbon dioxide (CO_2) is injected into oil reservoirs to increase oil recovery. The object is also the interphase phenomena, geochemical interactions and technological operations for well control associated with these processes.

One of the most problematic areas is the lack of understanding of complex relationships. These relationships exist between physicochemical processes at the micro level (interfacial tension, wettability, solubility, adsorption, geochemical reactions) and macroscopic characteristics of the reservoir (permeability, porosity, heterogeneity). Technological parameters of CO_2 injection (pressure, temperature, speed, volume) are also important. This leads to suboptimal selection of technologies for increasing oil recovery technologies, premature CO_2 breakthroughs, low oil recovery ratios, and also complicates the prediction of the behavior of the "reservoir – fluid – CO_2" system in the long term, in particular, from the point of view of CO_2 storage safety. Another problematic area is the limitation of existing empirical models describing the impact of CO_2 injection on well productivity, which do not fully take into account the heterogeneity of the reservoir and the complexity of physicochemical processes.

A comprehensive overview of the mechanisms of CO_2 interaction with reservoir fluids and rock has been obtained. The impact of supercritical CO_2 on interfacial tension, wettability, swelling and viscosity of oil has been analyzed. Geochemical reactions and their impact on permeability have been considered. CO_2 mobility control has been investigated. Mathematical relations for the calculation of throttling devices have been developed. An analysis of industrial data has been conducted, which revealed a nonlinear response of wells and allowed to refine regression models.

This provides the possibility of obtaining increased oil recovery rates and long-term CO_2 binding. Compared with similar known methods, CO_2 provides a decrease in interfacial tension, a decrease in oil viscosity, dissolution of residual oil and a potential reduction in greenhouse gas emissions. Refined regression models allow for a more accurate prediction of well productivity. The developed mathematical relationships provide effective well management. The results obtained can be used in practice to optimize oil field development processes using CO_2 injection technologies, as well as to assess and ensure the safety of long-term CO_2 storage in geological formations.

Keywords: *carbon dioxide, oil recovery, multiphase filtration, permeability, geochemical interactions, wettability, fittings.*

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1. Introduction

Increasing oil recovery is a key challenge for the oil and gas industry, especially in light of depletion of reserves and increasing demand. CO_2 injection is attracting attention due to its efficiency and ability to bind greenhouse gases [1]. CO_2 displaces oil by reducing interfacial tension and its viscosity [2]. The efficiency depends on the properties of fluids, reservoir geology and injection parameters. Insufficient understanding of these factors leads to suboptimal oil recovery, CO_2 breakthroughs and storage risks. The development of well control technologies for CO_2 injection is important [3].

The aim of research is to identify the patterns of influence of supercritical CO_2 properties, interfacial phenomena, geochemical reactions and reservoir heterogeneity on oil displacement and CO_2 storage.

2. Materials and Methods

2.1. The object of research

The object of research is multiphase filtration processes in porous media. These processes occur when carbon dioxide (CO_2) is injected into oil reservoirs to enhance oil recovery. The interfacial phenomena, geochemical interactions, and well management operations associated with these processes are also covered. The studies cover a wide range of conditions typical of real oil fields, including different types of reservoir rocks (carbonate, terrigenous), different oil compositions (from light to heavy), and different thermobaric conditions.

2.2. Research methods

The results of experimental studies published in the scientific literature on fluid filtration through core, measurement of interfacial tension, wettability, and phase behavior of CO_2 and hydrocarbon mixtures were analyzed and summarized. Statistical analysis of industrial data (flow rates, water intrusion, pressure) using regression analysis was performed, as well as analysis and synthesis of field test data of CO_2-enhanced oil recovery technologies. The conditions considered in the studies corresponded to those of oil fields with CO_2 injection.

3. Results and Discussion

3.1. Interphase phenomena and phase behavior

Under reservoir conditions characterized by pressures higher than 73.9 bar and temperatures higher than 31.1 °C, carbon dioxide (CO_2) transitions to a supercritical state. The phase diagram of CO_2 illustrating this transition is presented in Fig. 1. In this state, supercritical CO_2 exhibits unique physicochemical properties, combining a liquid-like density (600–800 kg/m^3) with a gas-like viscosity (0.02–0.1 cP), making it an effective agent for enhancing oil recovery, especially in low-permeability and shale reservoirs. This dual behavior promotes deep penetration of supercritical CO_2 into low-permeability matrices, where capillary forces at the inlet play a dominant role [4]. The minimum miscibility pressure, the thermodynamic threshold that determines complete miscibility between CO_2 and oil, is governed by multicomponent interactions, including van der Waals forces and dipole-induced polarization effects. Recent molecular dynamics simulations show that CO_2 preferentially interacts with light hydrocarbons (C_1–C_6) in kerogen nanopores, displacing adsorbed oil through competitive adsorption and dissolution [5]. Above the minimum miscibility pressure, the interfacial tension decreases to values close to zero, eliminating capillary entrainment and ensuring single-phase flow. However, achieving complete miscibility is often impractical due to operational constraints, which has led to interest in regimes close to miscibility (0.87–1.07), where the reduction in interfacial tension and mixing viscosity are maintained without the need for excessive pressures [6].

The dissolution of supercritical CO_2 in oil leads to its swelling (volumetric expansion by 10–40 %, depending on the oil composition and thermobaric conditions) and a decrease in viscosity by 50–90 %. These effects are due to entropic changes during mixing and changes in the enthalpy of the system. The swelling efficiency correlates with the density of the oil on the API scale: lighter oils (≥30° API) absorb 20–30 % more CO_2 by mass than heavier oils (≤15° API). This is explained by the higher solubility of supercritical CO_2 in hydrocarbons with a lower molecular weight. The decrease in oil viscosity, in turn, improves the mobility ratio ($\mu_0/\mu CO_2 \sim 10^{-2}$–$10^{-3}$), which contributes to reducing the effect of displacement instability (viscous tongue formation) and increasing the efficiency of oil displacement.

Experimental studies with core flooding demonstrate that the use of cyclic (asynchronous) injection of supercritical CO_2 with a subsequent holding period and production in low-permeability reservoirs allows increasing microscopic oil recovery ratios up to 86 % [7]. This effect is achieved by optimizing the dynamics of dissolution-expansion of supercritical CO_2 in oil and mobilizing residual oil held by capillary forces in micro-heterogeneities of the pore space (for example, in pore constrictions and dead-end pores).

3.2. Interfacial tension reduction

Reducing the interfacial tension between CO_2 and oil is a critical mechanism for enhancing oil recovery and improving displacement efficiency. Dissolving CO_2 in the water or oil phases induces competitive adsorption at the liquid-liquid interface. This displaces natural surfactants and changes the surface charge dynamics. As a result, the interfacial tension is reduced by 1–2 orders of magnitude. When CO_2-saturated water is injected, CO_2 diffuses into the oil. This ionizes the main components of the oil (e.g., asphaltenes and resins), forming in-situ natural surfactants. The latter reduce the interfacial tension. This process is highly dependent on the oil composition. Sour oils (those containing significant amounts of organic acids) exhibit increased interfacial tension at low pH due to suppressed ionization. Low-acid oils, on the other hand, reduce interfacial tension. This is due to the activation of surfactants caused by pH [8]. Pressure and temperature also play an important but ambiguous role. Higher pressure increases the solubility of CO_2, contributing to the reduction of interfacial tension. Increased temperature can either increase molecular mobility (reducing interfacial tension) or reduce CO_2 solubility (increasing interfacial tension). The final effect depends on the thermodynamic equilibrium of the system and the specific composition of the oil. Studies [9] show that reducing salinity and using nanoparticles (silica or clay) enhance the reduction of interfacial tension. This is due to the modification of the interfacial charge and better dispersion of CO_2. However, the effectiveness of such methods depends on the mineralogy of the rock. Also important is the heterogeneity of the pore space.

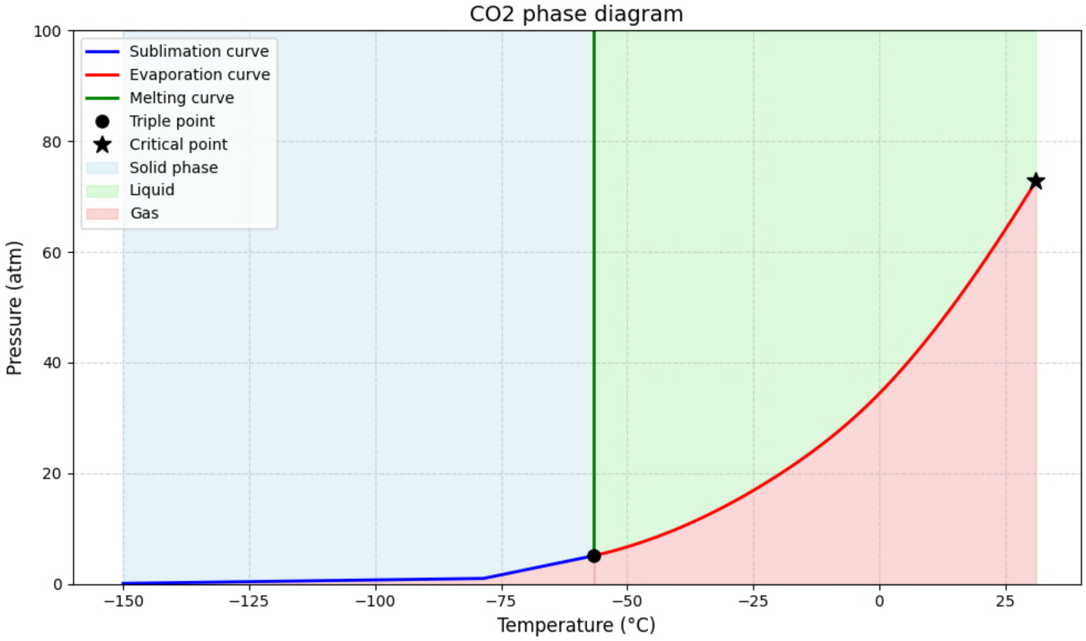

Fig. 1. CO_2 phase diagram

Mobility control strategies aim to reduce the low viscosity and high mobility of CO_2, which often lead to unstable displacement (viscous tongue formation) and early breakthrough of the displacing agent. Traditional methods, such as alternating water-gas injection, suffer from water shielding (where water blocks access of CO_2 to the oil) and surfactant adsorption in highly heterogeneous formations, which limits their effectiveness. New solutions focus on chemically increasing the viscosity of CO_2 or stabilizing its flow. For example, fluorinated acrylate thickeners dissolve in supercritical CO_2, forming intermolecular associations that increase the viscosity by a factor of 2–5, thereby improving the mobility ratio and displacement efficiency without the need for water injection. CO_2 nanobubble systems (<200 nm in diameter) are another promising approach. They are stabilized by surfactants or nanoparticles. These systems exploit the effects of increased surface curvature to reduce interfacial tension. They also increase the number of capillaries (a dimensionless parameter that characterizes the ratio of viscous forces to interfacial tension forces) by a factor of 2–3. This allows oil to be displaced from pores smaller than 10 nm. These nanobubbles also improve mass transfer efficiency. Mass transfer coefficients (KLa) are increased by a factor of 11 compared to conventional CO_2 delivery methods. Their stability helps overcome gravitational forces and uneven fluid movement through high-permeability zones (fractures) in fractured reservoirs.

These strategies allow for macroscopic recovery rates exceeding 80 %, demonstrating a synergistic balance between enhanced oil recovery and long-term CO_2 storage.

3.3. Geochemical interactions

Geochemical interactions between CO_2, formation fluid (mineralized water), and reservoir rocks play a key role in determining the long-term stability and security of carbon storage. When CO_2 dissolves in formation fluid, it forms carbonic acid ($pH \sim 3–4$, this range is approximate and depends on reservoir conditions), which initiates mineral dissolution-precipitation cycles, especially in carbonate-rich formations. For example, calcite and dolomite dissolve at rates of $10^{-9}–10^{-11}$ mol/cm^2/s, widening pore constrictions by 5–20 % over decades, thereby increasing the permeability of carbonate reservoirs. However, this dissolution can also disrupt the integrity of the impermeable cap overlying the reservoir, breaking down fracture seals or well cement, increasing the risk of leakage if acidic fluids migrate into overlying formations [10]. Conversely, mineral deposits (e. g. secondary carbonates) can stabilize the reservoir by reducing permeability and sealing fractures. Reactive transport modeling has been performed using tools such as PHREEQC and TOUGHREACT. The results show that limestone deposits experience a 16.12 % increase in porosity due to calcite dissolution. Sandstones show minimal changes. This highlights those geochemical reactions are highly dependent on rock type [10]. In addition, CO_2 adsorption on organic-rich shales increases the storage capacity by 17.8 %, as the organic matter provides active sites for CO_2 physisorption, further reducing buoyancy-induced migration [11].

It is important to consider the potential impact of the Rehbinder effect on the mechanical properties of rocks when interacting with CO_2. The adsorptive strength reduction inherent in this effect can play a role in intensification of mining and rock failure. Adsorption of CO_2 and other components on the surface of pores and fractures reduces the free surface energy, facilitating deformation and failure of the rock under the influence of reservoir pressure, which promotes the formation of new fractures. This is especially relevant when using hydraulic fracturing technologies.

Long-term storage safety depends on balancing these geochemical dynamics. Over millennia, up to 95 % of the injected CO_2 dissolves in the reservoir fluid, and 5 % is sequestered through the formation of stable carbon-containing minerals (mineral traps), depending on the initial mineralogy. For example, modeling of the Shihezi Formation demonstrates that dissolution of K-feldspar and albite releases cations that promote carbonate precipitation, increasing the rate of mineralization even in systems with low mineral reactivity. However, asphaltene precipitation in CO_2-saturated zones can negate gains by plugging the pore throat, requiring compatibility testing prior to injection to reduce reservoir damage caused, for example, by asphaltene precipitation [10]. Modern imaging techniques such as dual-energy CT scanning have revealed non-uniform dissolution fronts in carbonate rocks at different Peclet (Pé) and Damkeler (Da) numbers, with wormhole formation observed in advection-dominated regimes ($Pé > 1$, $Da > 1$). Field studies such as the Frio pilot project highlight the importance of changing contact area between CO_2 and reservoir fluid. These changes occur at different stages of plume development. This highlights the need for dynamic geochemical modeling to predict the long-term behavior of reservoir fluids.

Integrating this knowledge with dielectric studies allows establishing a relationship between rock polarization and reaction kinetics. This helps to refine predictions of CO_2, reservoir fluid, and rock interactions. In particular, it becomes possible to better understand the processes of rock wetting by different fluids. It also improves understanding of interfacial interactions in the system. This eliminates critical uncertainties in the safety of carbon dioxide storage.

3.4. Chemistry of CO_2 formation interactions

In oil-bearing carbonate reservoirs, supercritical CO_2 actively interacts with light hydrocarbons. These hydrocarbons include $C_1–C_6$ compounds, such as methane (CH_4), ethane (C_2H_6), and propane (C_3H_8). The interaction occurs through dissolution and competitive adsorption in the nanopores of kerogen. This process leads to the displacement of adsorbed oil from the pores. The wettability of the rock also changes from petrophilic to intermediate. With petrophilicity, the rock is predominantly wetted by oil. With intermediate wettability, the rock interacts equally with both oil and water [4]. The change in wettability occurs because supercritical CO_2 has a lower surface energy than oil and is therefore more likely to adsorb on the rock surface. Kerogen is a complex mixture of organic compounds that can contain both hydrophilic and hydrophobic regions. Supercritical CO_2 selectively interacts with hydrophobic sites, displacing oil from them. This change in wettability helps to retain CO_2 as thin films in smaller pores, increasing storage safety while avoiding the need for water injection for capillary capture [12].

Recent advances in CO_2 nanobubble systems (<200 nm in diameter) further stabilize the $scCO_2$ distribution. This stabilization is due to interfacial curvature effects (the Laplace effect). The Laplace effect is that the pressure inside a smaller bubble is higher than the pressure inside a larger bubble. This effect is described by the equation:

$$\Delta P = 2\frac{\gamma}{r}, \tag{1}$$

where ΔP – the pressure difference between the two phases, γ – the interfacial tension, and r – the radius of curvature of the interface.

For nanobubbles with a small radius (r), the pressure difference (ΔP) becomes significant. This contributes to their stability and penetration into the smallest pores. Nanobubbles reduce the interfacial tension in the system. They also improve the capillary numbers (Nc) by a factor of 2–3. This makes it possible to displace oil from pores smaller than 10 nm. This is especially important in reservoirs with ultra-low permeability (less than 0.1 mD) [13].

At the molecular level, CO_2 interacts with hydrocarbons via Van der Waals forces (dispersion, dipole-dipole, and induction interactions) and electrostatic interactions, displacing adsorbed alkane chains from the pore surface. Molecular dynamics simulations show that supercritical CO_2 competitively adsorbs on mineral surfaces (e. g. silica (SiO_2) or calcite ($CaCO_3$)), extracting heavy hydrocarbons through a "solvate layer" mechanism. Van der Waals forces are weak intermolecular forces, but they play an important role in the interaction of nonpolar molecules such as CO_2 and hydrocarbons. For example, in nanopores < 10 nm, confinement effects modify the phase behavior: the conditions for bubble formation are reduced by 20–40 % for light oils, but increased for heavy oils, changing the extraction kinetics [6]. Surfactants further modulate the interfacial elasticity, stabilizing CO_2 foams by reducing Ostwald ripening (transfer of CO_2 from smaller to larger bubbles) and coalescence (fusion of bubbles). Molecular dynamics studies show that surfactants form monolayers at the CO_2-water interface. An example of such a substance is sodium dodecyl sulfate SDS ($C_{12}H_{25}SO_4Na$). These monolayers reduce the interfacial tension to 0.5 mN/m. They also increase the durability of the foam by 50 % under reservoir conditions. SDS is an anionic surfactant with a special structure. It has a hydrophobic hydrocarbon "tail" ($C_{12}H_{25}$). It also contains a hydrophilic "head" (SO_4^-, Na^+). At the CO_2-water interface, SDS molecules are oriented in such a way that their hydrophobic tails are directed towards CO_2 and their hydrophilic heads towards water, forming a stabilizing monolayer.

Asphaltene deposition is caused by CO_2-induced deasphalting. This process can be reduced by molecular design of special inhibitors. Inhibitors disrupt the π–π stacking between asphaltene molecules. π–π stacking is the interaction between the planar aromatic rings of asphaltene molecules. This interaction leads to the aggregation of asphaltenes. The use of inhibitors allows to maintain permeability in fractured reservoirs [6].

3.5. Well control taking into account interphase phenomena: technological fundamentals and calculation of throttle devices

Managing the processes of well development and operation, especially when using CO_2 for enhanced oil recovery, involves a deep analysis of the hydrodynamics of the "reservoir-lift" system. This system includes a porous reservoir saturated with oil, water and, in our case, CO_2, a well connecting the reservoir to the surface, and lifting equipment (pump and compressor pipes, fountain fittings). In this system, the forces of pressure, gravity, viscosity, interfacial tension, as well as capillary forces in a porous medium act.

The key task is to control the pressure gradients and flow rates of fluids (oil, water, CO_2) to optimize production and minimize energy losses. Throttle devices (nozzles) play a central role in this regulation, controlling the flow regimes by changing the hydraulic resistance in the path of fluid movement. Nozzles are classified into devices with a fixed cross-sectional profile (sleeve or disc) and with a dynamically adjustable profile (needle, drum and bar mechanisms). Fixed nozzles ensure stable operation due to a constant pressure drop, while adjustable ones allow to adapt to changing reservoir conditions (changes in reservoir pressure, water intrusion, gas factor) by changing the area of the passage channel. When using CO_2 to enhance oil recovery, especially in the supercritical state, nozzle control becomes particularly important. Supercritical CO_2 has unique properties, combining liquid-like density with gaseous viscosity. This affects the dynamics of oil displacement, reducing interfacial tension and changing the wettability of the rock. Accordingly, the choice of the nozzle diameter should take into account these features to ensure the optimal displacement mode and avoid, for example, premature breakthrough of CO_2 to the production wells.

Even in the stationary gushing mode, stochastic (random) fluctuations in the flow rate with an amplitude of 3–8 % are observed, which exceeds the errors of modern measuring systems (2–4 %). These fluctuations can be caused by the heterogeneity of the formation (changes in permeability, porosity), phase transitions, as well as turbulence of the flow in the well. To effectively distinguish the useful signal from noise, it is necessary that the flow rate increase ΔQ exceeds the sum of natural fluctuations δ_{nat} and instrumental errors δ_{inst}:

$$\Delta Q > \delta_{nat} + \delta_{inst}. \qquad (2)$$

Optimization of the choice of throttling devices requires the integration of multiphysics models. These models must take into account the phase behavior of fluids (especially the change in density and viscosity of CO_2 when passing through critical points), as well as the geomechanical response of the formation (changes in the stress-strain state of the rock under the influence of pressure fluctuations). In supercritical conditions, CO_2 exhibits properties similar to a liquid, but with gaseous mobility, which significantly affects the dynamics of oil displacement and requires specific throttling parameters (optimal nozzle diameter and its change mode). For example, too large a pressure drop across the nozzle can lead to the formation of emulsions, which complicates further production and separation of fluids. The duration of transient processes correlates with dimensionless numbers. One such number is the Reynolds number (Re). It characterizes turbulent flows in the riser. Another important indicator is the Bio number (Bi). This number characterizes the ratio between the internal thermal resistance of the formation. It also reflects the external heat and mass exchange of the reservoir with the surrounding environment. The Reynolds number determines the flow regime:

$$\mathrm{Re} = \frac{\rho v d}{\mu}, \qquad (3)$$

where ρ – the fluid density, v – the flow velocity, d – the characteristic size, μ – the dynamic viscosity). At $\mathrm{Re} < 2300$ the flow is laminar, and at $\mathrm{Re} > 2300$ it is turbulent.

At $\mathrm{Re} > 2300$ nonlinear effects such as cavitation or water hammer occur, which can destabilize the system and even lead to equipment failure. The Bio number shows how quickly heat (or substance) is transferred inside the formation compared to the rate of heat (or substance) transfer at the boundary between the formation and the well:

$$Bi = \frac{hL_c}{k}, \qquad (4)$$

where h – the heat transfer coefficient, L_c – the characteristic size of the body, k – the thermal conductivity.

Low values of Bi indicate that diffusion processes prevail over convective ones.

Temperature also significantly affects the processes taking place. Temperature changes affect the density, viscosity, and solubility of components.

Assuming a relative change in flow rate equal to the average value of A_{av}, the flow stabilization condition can be formalized by the relation:

$$\frac{\Delta Q}{Q} \geq A_{av}, \qquad (5)$$

where ΔQ – the absolute change in flow rate, Q – the current flow rate. For the entire regulation range B_r, the maximum number of M_c control levels in the nozzle device is determined by the equation:

$$\frac{B_r}{A_{av}} = M_c. \qquad (6)$$

Empirical data show that the dependence of flow rate on the nozzle diameter in a certain regulation interval is described by a power function:

$$Q = k_p D^{m1}, \qquad (7)$$

where Q – the well flow rate, D – the equivalent nozzle diameter, k_p – the proportionality coefficient, and n_1 – an empirical index (0.65–0.9) that takes into account the properties of the fluid and the formation.

Combining (5) and (7), let's obtain a differential equation for calculating the diameters of the fittings that provide a given relative change in flow rate:

$$\frac{1}{Q}\frac{dQ}{dx}\Delta x=\frac{n_1}{D}\frac{dD}{dx}\Delta x=A_{av}, \tag{8}$$

where dx – the elementary displacement of the throttle mechanism, Δx – the complete transition between the control levels. Integrating the second part of (4), we obtain:

$$\int\frac{\mathrm{d}D}{D}=\frac{A_{av}}{n_1\Delta x}\int \mathrm{d}x+C, \tag{9}$$

where C – the integration constant. Taking into account the initial conditions ($D=D_0$ at $m'=0$), the solution takes the form:

$$D=D_0\frac{B_r m'}{e_{n1}M_c}, \tag{10}$$

where D_0 – the initial diameter of the fitting, m' – the current control level ($m'=0, 1, 2, \dots, M_c$). For the control interval:

$$B_r=\frac{Q-Q_0}{Q_0}. \tag{11}$$

The formula simplifies to:

$$D=D_0 e^{\frac{m'}{n1M_c}}. \tag{12}$$

The equivalent area of the fitting through hole is calculated as:

$$F=F_0 e^{2B}cp^{\frac{m'}{n1M_c}}, \tag{13}$$

where F_0 – the initial area. Substituting (7) into (3), the predicted well flow rate is expressed as:

$$Q=k_p D_0^{n1} e^{B} cp^{\frac{m'}{M_c}}. \tag{14}$$

Taking into account the initial productivity Q_0, the general dependence of the flow rate on the regulation level is described as:

$$Q=Q_0 e^{B} cp^{\frac{m'}{M_c}}. \tag{15}$$

The accuracy of the coincidence of the calculated flow rates with the actual ones will be the greater, the smaller the regulation range B_r and the average value of the relative change in productivity A_{av} when transferring the well from one mode.

Dependences of the flow rate and water intrusion of wells after well treatment on the flow rate and water intrusion before treatments $W_{\downarrow BT}$ carried out in 1995–2016. The results of well treatment carried out in 2015 confirm the validity of the equations given in Table 1.

The expansion of the data sample that formed the basis of the analysis by 2.5 times (which is clearly visible when comparing Fig. 2 and Fig. 3) made it possible to significantly increase the statistical significance of the results. This, in turn, made it possible to revise the existing empirical models that describe the impact of various technologies for intensification of hydrocarbon production on well productivity. In particular, methods for increasing oil recovery are considered, which may include the injection of various agents, including carbon dioxide (CO_2). A key aspect of the analysis was a detailed study of the changes that occurred in the coefficients of the regression equations. These equations establish a relationship between the main indicators of well performance, such as liquid flow rates and water intrusion, before and after the relevant technological operations. The change in parameters in these regression equations clearly indicates the presence of a nonlinear nature of the well response to the applied technologies. This, in turn, stimulates the need for a deeper study of the fundamental mechanisms of interaction between fluids in the porous medium of the reservoir. Particular attention is paid to the study of processes during the injection of displacement agents, such as CO_2, taking into account their impact on phase equilibria and rheological properties of reservoir systems.

Table 1

Dependence of the change in the flow rate and water intrusion of wells on the initial values after treatments

Sample size	Equation of the relationship between increase and change	Interval of change in flow rates (t/day) and water intrusion (%)	Reliability of approximation (R^2)
257	$\Delta Q_0=0.694+1.634\cdot W_{\downarrow BT}$	0.2–10	0.794
	$\Delta Q_0=-2.097+0.894\cdot W_{\downarrow BT}$	25–100	0.714

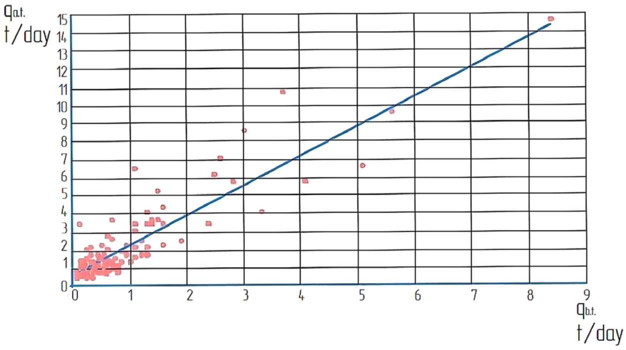

Fig. 2. Dependence of well flow rate after treatment on flow rate before treatments carried out in 1995–2016

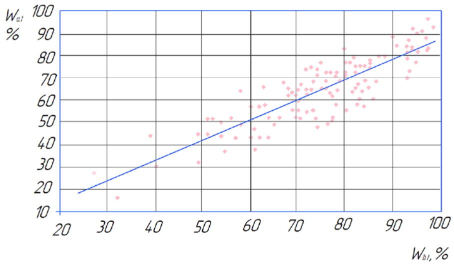

Fig. 3. Dependence of well water intrusion after treatment on water intrusion before treatments carried out in 1995–2016

The changes observed in the free terms, as well as the coefficients for the variables in the regression equations, indicate that wells belonging to different categories in terms of their characteristics demonstrate different reactions to the production intensification measures carried out. For example, in the equation describing the relationship between flows, an increase in the free term by 0.214 t/day and a simultaneous decrease in the coefficient for the corresponding variable by 0.056 are observed. This indicates that low-flow wells have become more sensitive to the operations carried out. This effect can be explained, for example, by the fact that in low-permeable zones of the reservoir, oil displacement by carbon dioxide (CO_2) occurs more effectively. This is due to the fact that in such zones, capillary forces play a significant role in retaining residual oil, and CO_2, due to its physicochemical properties (solubility in oil and reduction of interfacial tension), can more effectively mobilize this oil. On the other hand, the decrease in the response to intensification observed in high-flow wells may be associated with the occurrence of breakthroughs of the injected agent (CO_2) through high-permeability channels and layers. This leads to the fact that a significant part of CO_2 does not participate in the oil displacement process, but passes through "transit", which reduces the efficiency of CO_2 use and can potentially lead to an increase in its emissions into the atmosphere. Similar patterns are observed in the equation describing the water intrusion relationship: an increase in the free term by 1.883 % and a decrease in the coefficient at the variable by 0.066. This confirms the complexity and multifactorial nature of displacement processes, especially in conditions of high-water intrusion of well products.

The results of the study are useful for assessing risks and ensuring the stability of CO_2 storage in geological formations, for a reasonable choice of storage sites and for optimizing injection processes. The study contributes to the combination of increased oil recovery and CO_2 storage.

The data obtained can be used to develop new displacement agents and optimize existing ones, as well as to improve methods of influencing the reservoir. They are an important contribution to the parameterization of mathematical models for simulating field development.

The study, although it covers a wide range of conditions, is based on certain simplifications in modeling the reservoir. Real oil reservoirs are characterized by much greater heterogeneity, which cannot always be fully taken into account. The analysis is based on a generalization of the results of experimental studies published in the scientific literature, the availability and quality of which may vary. Transferring the results obtained in laboratory models to real reservoir conditions is a difficult task, since scaling effects can significantly affect the behavior of the system. When CO_2 is injected into an oil reservoir, a large number of interconnected physicochemical processes occur, which are extremely difficult to take into account within the framework of a single study. Regression models approximate real dependencies, but do not fully reveal causal relationships.

Martial law in Ukraine has made adjustments to the conduct of the study. Restrictions on access to infrastructure, field studies, and industrial data will affect the scope and timing of the work.

4. Conclusions

The study revealed patterns of influence of supercritical CO_2 properties, interfacial phenomena, geochemical reactions and reservoir heterogeneity on oil displacement and CO_2 storage. Mathematical relations were developed for calculating throttling devices that provide effective well control during CO_2 injection. An analysis of industrial data was conducted, which revealed a nonlinear response of wells and allowed to refine regression models describing the impact of CO_2 injection on productivity.

It was shown that the use of supercritical CO_2 allows to reduce interfacial tension by 1–2 orders of magnitude, reduce oil viscosity by 50–90 %, and increase microscopic oil recovery coefficients up to 86 % in low-permeability reservoirs. It was established that geochemical reactions can lead to an increase in the porosity of limestone rocks by 16.12 %.

Refined regression models allow for more accurate prediction of well performance, and the developed mathematical relationships allow for effective management of wells. The results obtained can be used in practice to optimize oil field development processes using CO_2 injection technologies, as well as to assess and ensure the safety of long-term CO_2 storage in geological formations.

The research results will be useful to field developers, petroleum engineers, and specialists in the field of geological modeling and CO_2 storage.

Conflict of interest

The author declares that he has no conflict of interest regarding this study, including financial, personal, authorship, or other nature that could affect the study and its results presented in this article.

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Data availability

The manuscript has no related data.

Use of artificial intelligence

The author confirms that he did not use artificial intelligence technologies when creating the presented work.

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