Modeling Carbon Dioxide Injection to Improve ORF in Low Permeability Reservoirs

Dmitry Klimov and Ernest Zakirov

Abstract For oil and gas fields with low-permeability formations, the most realistic way of their development is the mode of depletion of reservoir energy. Often, additional production is facilitated by the implementation of multi-stage hydraulic fracturing in production wells with their various modifications. Carbon dioxide is often used as an agent for increasing oil recovery factor, which is also considered within the framework of projects for its utilization and underground storage in depleted deposits, salt-bearing strata and shale rocks. Carbon dioxide is also actively used as an agent for the intensification of hydrocarbon production in the development of oil and gas fields. It is important to understand the ongoing physical and chemical changes occurring within the underground formation in case of carbon dioxide injection. Examples of these changes include dissolution, chemical reactions, convective mixing, advective processes, and dispersion. Computer modeling of the ongoing processes is seen as a very important task for the correct functioning of such projects. This study is a summary of the results of computer modeling of a method for developing oil and gas fields with low-permeability formations based on maintaining reservoir pressure by injection of carbon dioxide using the commercial software Navigator.

Keywords Mathematical modeling · Low-permeability reservoirs · Hydrocarbons · Hydraulic fracturing · Carbonated water · Carbon dioxide · Depletion mode · Pressure maintenance mode · Oil recovery factor

1 Introduction

Every year the share of hard-to-recover reserves is increasing, and the active part of light oil reserves is being rapidly developed. At the same time, the share of reserves, for example, high-viscosity oils, is increasing more and more. Due to the growth in the share of hard-to-recover reserves, it becomes necessary to increase the efficiency of their extraction, to improve the technologies for their production. Moreover, the oil

D. Klimov (✉) · E. Zakirov
Oil and Gas Research Institute, Russian Academy of Sciences (OGRI RAS), Gubkina st., 3, Moscow, Russian Federation 119333

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recovery factor (ORF) by traditional methods in fields with hard-to-recover reserves rarely exceeds 30%, and in high-viscosity oil fields it is even lower.

For oil and gas fields with low-permeability formations, the most realistic way of their development is the mode of depletion of reservoir energy. However, it is known that the depletion mode is usually characterized by the minimum values of the oil and gas recovery factors. Often, additional production is facilitated by the implementation of multi-stage hydraulic fracturing in production wells with their various modifications.

It is known that the most significant of the properties of productive formations is the permeability coefficient. Wells production rates for oil, gas, condensate and other development indicators depend on the values of the reservoir permeability coefficient.

Until recently, reservoirs with a permeability of 1 mD or more were not considered viable development targets. Today the situation has changed. Thus, in the United States, they began to successfully develop oil and gas fields with shale, low-permeability formations. In such formations, the permeability is about or markedly below 1 mD. Extraction of shale oil and shale gas begins to develop in other regions [1].

The era of 3D computer modeling that began in the 2000s forced a change in the attitude towards low-permeability formations. Thus, the need to include low-permeability formations with their own values of porosity and permeability in 3D-geological and 3D-hydrodynamic models of the reservoir or the field as a whole was justified. Thus, the authors had the following fundamental idea. The highest oil recovery factor and the least negative consequences of waterflooding will occur if oil from low-permeability reservoirs is displaced by a working agent into high-permeability reservoirs. In turn, oil from highly permeable reservoirs can be displaced to production wells by oil inflowed from low-permeability areas.

2 Materials and Methods

The situation with low-permeability reservoirs in the last decade has changed dramatically in connection with the development in the United States and other countries of oil deposits with ultra-low values of permeability [2]. It is known that this became possible due to the drilling of long horizontal wells and carrying out in them reusable, multi-stage hydraulic fracturing of the formation. This technology is widely used in the development of both conventional and unconventional fields.

As an example, Fig. 1 shows the layout of planned wells in the largest shale oil field in the United States, Barnett Shale Play. The peculiarity of the development of this and other similar fields is as follows: most of them are developed in the regime of depletion of reservoir energy. It is known that in such cases the flow rates of the wells decrease rather quickly in time. Therefore, in order to maintain a constant level of production at the field, more and more wells are drilled with the implementation of

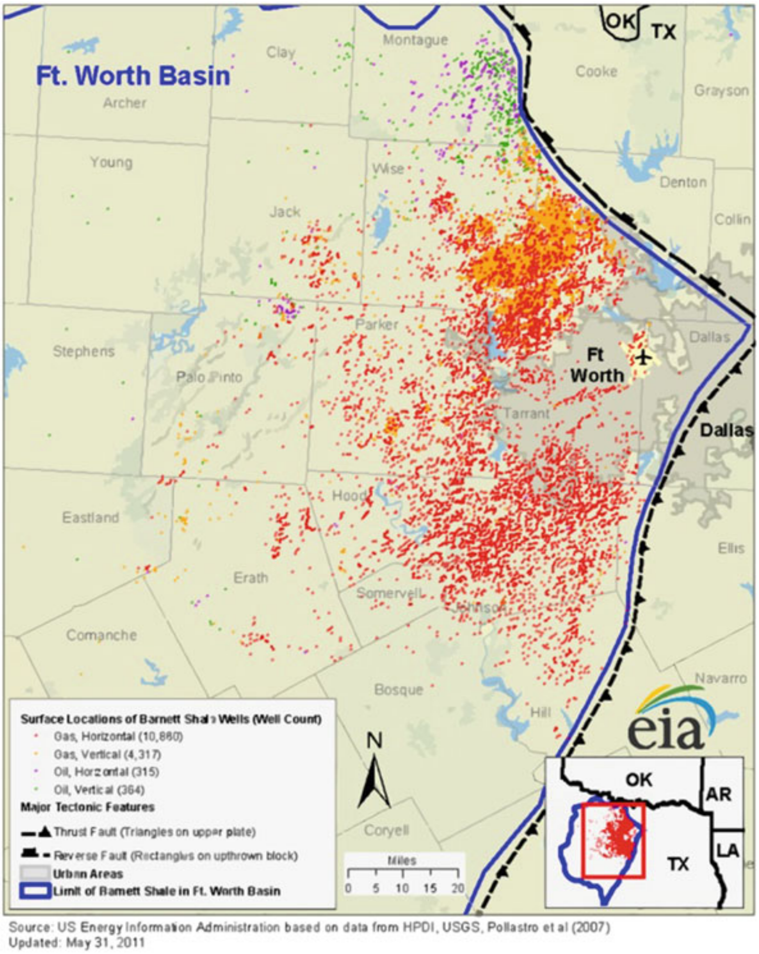

Fig. 1 Map of gas wells in the Barnett Shale, Texas. *Source* [3]

multi-stage hydraulic fracturing in the production wells. Judging by the publications [2], this development technology turns out to be cost-effective.

In some wells, the fracturing operation has to be repeated many times to maintain a stable flow rate. However, even despite the use of horizontal drilling and hydraulic fracturing technologies, the productivity of existing wells decreases much faster than in traditional fields. So, if the average "life" of gas wells in traditional US fields is 30–40 years, then about 15% of shale wells drilled in 2003 have completely exhausted their resources in 5 years.

Due to the low permeability of the reservoirs, gaseous agents deserve attention as a working agent. Among the world practice of patent applications and issued patents for the production of gas and oil from unconventional reservoirs, the experience of using hydraulic fracturing using carbon dioxide is of interest in the framework of our research [2]. This method is carried out by injecting supercritical CO_2 to treat the formation through the wellbore at a pressure higher than the fracturing pressure. The formation being treated may have a permeability of less than 1 mD. By pumping a CO_2 agent into the formation at a pressure higher than the fracture pressure, the formation integrity can be effectively compromised, which stimulates the flow of methane and other hydrocarbon gases into the well. That is, the use of CO_2 during hydraulic fracturing is promising from the point of view of increasing the total gas production due to the ability of CO_2 to displace methane.

The feasibility and efficiency of various technologies used in the development of traditional oil fields, based on the injection of carbon dioxide in various modifications, is currently beyond doubt. Moreover, there is an abundance of anthropogenic sources of carbon dioxide, and its modern emissions into the atmosphere are enormous. Therefore, the injection of carbon dioxide into oil reservoirs in various states and forms (for example, in the form of carbonated water) seems to us in the framework of the study of low-permeability reservoirs reasonable, logical, which at the same time requires specific laboratory studies and the compilation of mathematical models.

It should be noted that some experts agree that oil and gas production based on hydraulic fracturing technology can be successfully combined with technologies for utilization, sequestration and long-term storage of CO_2 in various geological formations. Geological sequestration and hydraulically fractured oil and gas share more than a location. They also face common issues such as groundwater contamination risks, water management issues, seismic risks, and general public acceptance [4]. Carbon dioxide sequestration refers to the process of capturing the excess CO_2 present within the atmosphere toward long-term storage. CO_2 storage arises from the need to mitigate the effects of global warming and serves as an avenue to reduce the rate of accumulation of greenhouse gases (GHG) arising from anthropogenic activities [5–7].

Sedimentary basins are considered to be promising targets for CO_2 storage as they have high-porosity and high-permeability layers represented by sandstones, and low-permeable and low-porosity caprocks represented by shale which limit the transfer of CO_2 toward the surface [5]. Thus, shale rocks, in addition to a new hydrocarbon source, can also represent underground storage-traps within the framework of international projects and programs for long-term conservation and utilization of carbon dioxide [6, 7].

Experimental study by Kang et al. [8], which examined the possibility of shale-rich core samples to be suitable for carbon dioxide storage, showed good results. According to the authors, despite the wide popularity of low-permeability sedimentary rocks with low porosity, organic shale has the ability to retain a significant amount of gas for a long time due to its ability to capture gas in an adsorbed state through finely dispersed organic matter (i.e., kerogen). The suitability of shale for CO_2 storage is also attractive because the spatial and thermodynamic effects of the processes occurring are similar to coal seams in methane extraction technologies.

Numerous research works [5, 9–17] have been proposed to understand the ongoing physical and chemical changes occurring within the underground formation in case of carbon dioxide injection. Examples of these changes include dissolution, chemical reactions, convective mixing, advective processes, and dispersion. There are some works devoted to modeling various processes of injection and storage of carbon dioxide in various formations, which should be mentioned.

A considerable amount of research has been conducted in simulating and modeling CO_2 sequestration in the subsurface. Calabrese et al. [9] studied the physical and chemical processes during CO_2 sequestration in a depleted gas reservoir located in the north of Italy. They concluded that to maximize the volume of CO_2 injected, an optimum rate has to be defined. At higher rates, the gas channels through high permeability streaks, and hence the storage capacity is reduced. While at lower rates, the denser CO_2 falls to the bottom of the gas zone and dissolves in the aquifer. They also concluded that molecular diffusion, dispersion, and geochemistry were not important factors for assessing the CO_2.

Seo and Mamora [10] performed experimental and simulation studies to evaluate the feasibility of sequestering supercritical CO_2 in depleted gas reservoirs. They performed experimental studies to obtain relative permeability curves; then, 3D simulation models of one-eighth of a five-spot pattern were used to evaluate the injection of CO_2.

Hesse [11] presented a compact multiscale finite volume (CMSFV) method for the numerical simulation of CO_2 storage in large-scale heterogeneous formations. The authors identified that dissolution is an important trapping process if CO_2 is present in a structural trap. They also concluded that high permeability aquifers favor dissolution trapping. The authors indicated that high permeability, gently dipping, and deep saline aquifers are the optimal targets for CO_2 sequestration.

Momeni et al. [12] presented a simulation study using ECLIPSE E300 (compositional simulation model) of a synthetic geologic model used to sequestrate CO_2. They concluded that the operating expenditure for sequestration in a depleted oil reservoir is less than in an aquifer because of lower well corrosion during injection. This is due to the higher brine concentration in an aquifer which increases the probability of corrosion.

Zhang and Agarwal [13] performed an optimization based on genetic algorithms to optimize the sequestration operation. They used the TOUGH2 solver developed by the US Department of Energy. They used both horizontal and vertical wells. Based on the results of the optimization, they concluded that the horizontal wells were much better when compared to vertical wells in aspects such as reduced migration and pressure build-up which could contribute to cap rock fracture and gas leakage.

Bao et al. [14] performed a large-scale CO_2 sequestration by coupling reservoir simulation with molecular dynamics (MD). The simulation was performed on massively parallel high-performance computing systems. They believed the coupling of molecular dynamics would provide better predictability of fluid properties under varying geological conditions. In their flow equations, they assumed the flow to be incompressible and used Darcy's equation to model the velocity in the reservoir. The advection diffusion equation was used to model the transport of CO_2 in the porous media. In the MD simulation, they solved Newton's equation of motion and the Leonard Jones and Coulomb interactions were used to represent the interaction between two atoms.

Hao et al. [15] developed a methodology to combine reservoir simulation, rock physics theory, and seismic modeling to simulate and monitor a sequestration process in an idealized geological model located in the Sleipner field. They modelled CO_2 injection using the two-phase flow model and solved the equations using the IMPES method. Then, they analyzed the effects of fluid saturation and pressure change on the elastic wave velocity based on the Gassman equation, Hertz–Mindlin theory, and effective fluid theory. Finally, seismic modeling was performed using P-wave potential equations and the symplectic stereomodeling (SSM) method on the transformed geologic model obtained from reservoir simulation.

Foroozesh et al. [16] performed a field scale simulation of an aquifer consisting of one well injecting CO_2 for ten years. The model was run for 100 years with the results showing that CO_2 solubility trapping was the main mechanism of sequestration. The simulation was performed using CMG-GEM. The results demonstrated that good vertical permeability and lower injection pressures are important factors in reducing leakage.

Mkemai and Bin [17] investigated the optimal injection strategy to enhance CO_2 storage. Their results concluded that an optimum injection pressure needs to be maintained as the pressure build-up created by injection may fracture the cap rock, which would then lead to CO_2 leakage. The authors highlighted that an optimum CO_2 sequestration does not lead to excessive migration of the injected gas.

The author's specialized laboratory experiments were also devoted to the search for effective technologies for the utilization and use of carbon dioxide as an agent for displacing hydrocarbons in oil and gas reservoirs. They revealed previously unknown physicochemical phenomena and polycondensation mechanisms of the interaction of carbon dioxide with rock models, which were expressed in the generation of hydrogen, methane and its homologues [18].

The authors' lack of the necessary set of required geological, physical and other information on a real field, as well as a software product for taking into account the experimentally identified physicochemical processes in predictive calculations, led to the solution of the synthetic model problem considered below.

3 Results

The results of the laboratory experiments [18] incite interest in injecting CO_2 into the oil bed in that or another phase conditions. However, the idea of injecting CO_2 into the oil bearing beds faces the limits determined by the permeability values. Therefore, it is for a good reason that most shale deposits are developed under of reservoir energy depletion. Unfortunately, the oil recovery factor (ORF) in such cases does not, as a rule, exceed ten percent. Therefore the computer assisted experiments have been performed for the oil carrying bed with the limit value of the effective permeability of 1 mD.

For the objectives of the study the model of multidimensional multiphase flow was used implemented within the commercial software package tNavigator developed by Rock Flow Dynamics [19]. This simulator implements an extended model of non-volatile oil, and the calculation results themselves are as close as possible to the results of the industry standard for multiphase filtration modeling—the Schlumberger Eclipse simulator.

The modeled productive bed is of low permeability (1 mD), it is not profitable by definition and belongs to "non-reservoirs" (non-pay reservoirs). Other initial data are as follows: initial reservoir pressure—23.3 MPa, oil saturation pressure—0.5 MPa, oil viscosity—1 MPa s, oil formation volume factor—1.6 m^3/m^3, formation thickness—20 m. As the bottom-hole pressure in the producing wells decreases down to 3 MPa further on it is kept unchanged. The bottom-hole pressure in the injection well is constant and it is equal to 30.3 MPa. The producing wells are shut when the oil production rate is reduced to 1 m^3/day (per a whole well). The relative permeability curves are assumed to be diagonal because of the high solubility of carbon dioxide in oil. The flow simulation model was represented by the Black Oil model. With such initial data the comparative calculations for alternative scenarios have been performed and are described below.

An element of a 5-spot development pattern is 500 × 500 m in size. It has been drilled with horizontal wells with lengths of 200 m. Around the horizontal part of the well bore the one-cell ring of the grid has been refined and the permeability values of these cells are 10 times higher than the permeability of the reservoir itself which simulates the technogenic fractures resulting from the multistage hydraulic fracturing. The schematic layout of the simulation element is shown in Fig. 2.

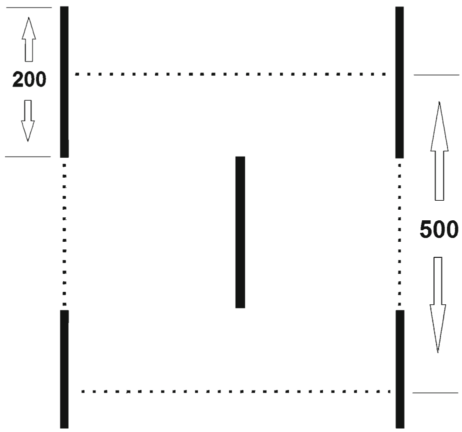

Fig. 2 Schematic layout of 5-spot development element

4 Discussion

The effect of CO_2 interphase exchange accompanied by dissolution in water and oil was not taken into account. No account was made for the volumetric properties of the phases depending on the amount of the dissolved CO_2. The ability of the water dissolved CO_2 to mix with oil was approximately accounted for by means of the diagonal relative permeabilities for the oil–water system.

The dimensions of the simulation grid were 43 × 43 × 10 grid cells. The grid is not uniform in the horizontal plane, with cell sizes being reduced down to 1 m × 1 m in the area of each well. Then the sizes of the cells were increasing exponentially preserving the preset total distance between the wells. Over the vertical plane the grid is uniform.

In «case 1» all wells in the development element are producing wells, i.e. the development is carried out under the depletion drive, the wells are producing at the bottom-hole pressure of 3 MPa.

In «case 2» one of the wells (the central one in the development element) becomes an injection well. Carbonized water of 1 MPa s viscosity is injected under the bottom-hole pressure of 30.3 MPa.

The results of the simulations for the cases under consideration are shown graphically in Figs. 3 and 4.

Figure 3 is of special interest here; it presents the comparison of the dynamics of ORF in the case with the depletion drive and in the case with the pressure maintenance. Hence, it is advisable to maintain the reservoir pressure in the low permeability reservoir under consideration. Though, here the dynamics of ORF in the case with the maintained pressure is somewhat too high, because the simulations were based on the model where the permeability of the oil reservoir was homogeneous and also some other assumptions have been made. However, there are several technological

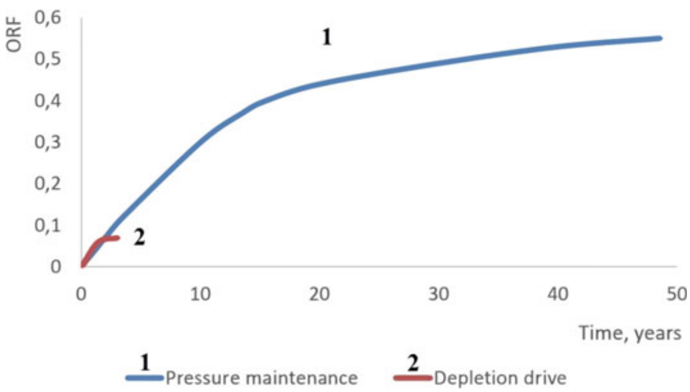

Fig. 3 Dynamics of oil recovery factor (ORF). *1*—pressure maintenance, *2*—depletion drive

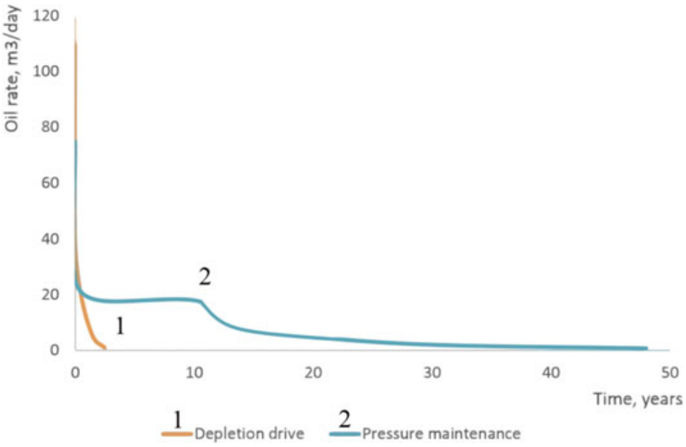

Fig. 4 Dynamics of oil production rate. *1*—depletion drive, *2*—pressure maintenance

methods for taking into account the inhomogeneity of the reservoir and for alleviating its negative implications. There are still additional reserves when, for example, the lengths of the horizontal wells are assumed to be equal to 1000 or 2000 m, etc.

The results presented in Fig. 3 can be understood in more detail upon considering Fig. 4 that shows the comparison of the oil production dynamics in different modes for the same development element. Here, it has to be noted that in the depletion mode the oil production from the development element appears to be somewhat higher in the beginning as compared to the case of pressure maintenance, because in the depletion mode a larger number of producing wells are in operation.

5 Conclusion

The results of the simulations correspond to an isolated case and are by no means absolute. Obviously, in this case a large number of cases have to be investigated; however, this was not included in the scope of this study. It is also obvious that some non-apparent effects will appear, inasmuch as in real environment the layered or zonal heterogeneity of the reservoir properties often affects negatively the economics of the oil field development.

Nevertheless, the undertaken numerical experiments with the simulation model prove at the qualitative level that developing the oil deposits with low permeability reservoirs by pressure maintenance using carbonized water injection could be very efficient and can result in higher ORF values. High oil recovery factors can be achieved due to the effects of additional hydrogen generation obtained in laboratory experiments [18].

The considered approach to the development is realistic not only when applied to the oil deposits but also when applied to gas-condensate and, in some cases, to gas deposits with low permeability reservoirs. Thus, if the reservoir pressure is not maintained in the gas-condensate field then the condensate will drop-off in the reservoir becoming immovable. That is, in case of the gas-condensate deposit the pressure maintenance is meant to solve the problem of condensate recovery in the first place. In case of the depletion mode the dropped-off condensate will drastically reduce permeability to gas which will lead to lower gas recovery factor (GRF). That means that maintaining the reservoir pressure in gas-condensate deposit will help improve GRF. Maintaining the pressure in the oil deposit and in gas-condensate deposit will make it possible to postpone the period of the compressor-driven exploitation. Besides, if the pressure is maintained in these deposits the volume of the low pressure gas will decrease considerably. Thus, ideally, when the CO_2 injected agent displaces all of the natural gas, there will be no low pressure gas left in the development formation.

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