

The efficiency of gas injection into low-permeability multilayer hydrocarbon reservoirs

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Abstract. The efficiency of gas injection for developing terrigenous deposits within a multilayer producing object is investigated in this article. According to the results of measurements of the 3D hydrodynamic compositional model, an assessment of the oil recovery factor was made. In the studied conditions, re-injection of the associated gas was found to be the most technologically efficient working agent.

The factors contributing to the inefficacy of traditional methods of stimulating oil production such as multistage hydraulic fracturing when used to develop low-permeability reservoirs have been analysed. The factors contributing to the inefficiency of traditional oil-production stimulation methods, such as multistage hydraulic fracturing, have been analysed when they are applied to low-permeability reservoirs.

The use of a gas of various compositions is found to be more effective as a working agent for reservoirs with permeability less than $0.005 \mu\text{m}^2$. Ultimately, the selection of an agent for injection into the reservoir should be driven by the criteria that allow assessing the applicability of the method under specific geological and physical conditions. In multilayer production objects, gas injection efficiency is influenced by a number of factors, in addition to displacement, including the ratio of gas volumes, the degree to which pressure is maintained in each reservoir, as well as how the well is operated. With the increase in production rate from 60 to 90 m^3 / day during the re-injection of produced hydrocarbon gas, this study found that the oil recovery factor increased from 0.190 to 0.229. The further increase in flow rate to 150 m^3 / day , however, led to a faster gas breakthrough, a decrease in the amount of oil produced, and a decrease in the oil recovery factor to 0.19

Based on the results of the research, methods for stimulating the formation of low-permeability reservoirs were ranked based on their efficacy.

Keywords. Gas injection, Low permeability reservoir, Multilayer formation, Reservoir pressure maintenance, Formation stimulation.

1. Introduction

It is often ineffective to develop oil fields with low-permeability reservoirs by using the traditional reservoir pressure maintenance (RPM) method such as multistage hydraulic fracturing (MSHF) [1-5]. The practice of developing low permeability reservoirs shows how the system differs significantly from the classical water-flooding method, which has shown to be an effective method for increasing the recovery of oil in terrigenous reservoirs with high flow properties.

Moreover, the possibility of using various compositions of gases as working agents can be an advantage when considering hard-to-recovery reserves (HTRR) as promising targets for development with the achievement of higher oil recovery factors (RF) [6–10]. It is imperative to measure the economic and technical efficiency of this approach in light of the policy of oil and gas companies to encourage profitable development of low-permeability fields [11-13].

2. Inefficiency of Using Traditional Pressure Maintenance Methods in the Development of Low Permeability Reservoirs

Traditionally, the development of hydrocarbon fields with hard-to-recovery reserves involves either hydraulic fracturing as a method of enhanced oil recovery (EOR) with further reliance on the field's own energy or water injection [14-17]. In spite of this, using water as a working agent to maintain reservoir pressure yields no tangible results. Thus, for reservoirs with permeability less than $0.025 \mu\text{m}^2$ and a 90% water cut, the maximum actual withdrawal of initial recoverable reserves (IRR) is 41.6% of its calculated value. Reservoirs with permeability less than $0.010 \mu\text{m}^2$ have actual oil recovery factors in the range of 0.014 to 0.235, with an average value of 0.138. In general, with a water cut of about 80%, the withdrawal of initial recoverable reserve is not more than 35–40% of its calculated value [18-21]. With such ratios of water cut and oil recovery, it can be argued that with the existing development system based on water injection, the calculated values of oil recovery factors are overestimated and will not be achieved [22–24]. Figure 1 shows the ratios of the initial recoverable reserves and the water cut in production during the implementation of the water flooding system.

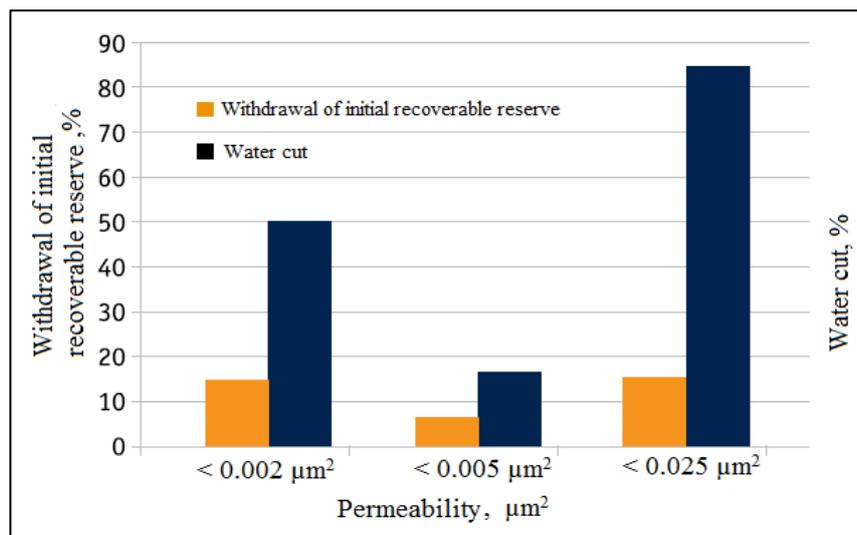


Figure1. Developing low-permeability reservoirs: Ratio of withdrawals of initial recoverable reserves and water cut

In the case of reservoirs with low flow characteristics and permeability less than $0.010 \mu\text{m}^2$, there can be a discrepancy of 70% or more between the design and actual values of oil recovery factor. In this context, reservoirs with such flow characteristics cannot be considered as promising objects for the implementation of a water-flooding system [25-28].

3. Potential Of Using Gas In The Development Of Low Permeable Reservoirs

One of the most promising methods for increasing displacement efficiency and RPM in a low-permeability reservoir is to use gaseous agents [29 - 33]. Several oil companies and research organizations have studied the phenomenon of oil displacement by gaseous compositions in laboratory conditions both on a real core and on combined bulk models.

Moreover, they perform numerous experiments using 3D hydrodynamic modelling (HDM), the results of which are widely used to evaluate and justify options for the development of oil and oil and gas condensate deposits with the injection of gaseous compositions [34-37].

With respect to the evaluation of gas based EOR efficiency, ranking and searching for the best source of gas in terms of efficiency can be done in two directions: with restrictions on the source of production and, accordingly, on the composition of the gas [38-40].

3.1 Field study

The last approach (composition of the gas) was used to assess the prospects for developing terrigenous deposits in the studied formation. The layers of the studied formation are characterized by low values of oil-saturated thickness - up to 5.0 m, the reservoir permeability does not exceed $0.005 \mu\text{m}^2$ and the viscosity of the reservoir oil is less than 1 mPa.s. The field study identified a multi-layer production facility with a 100 m difference in depth between upper and lower layers, which meets the requirements for layer combining.

Before starting the calculations, a thorough assessment of the geological and physical conditions was performed to determine whether each of the gases, which could theoretically be used to stimulate oil inflow, met the applicable criteria. The results of ranking from best to worst are shown in Fig.2.

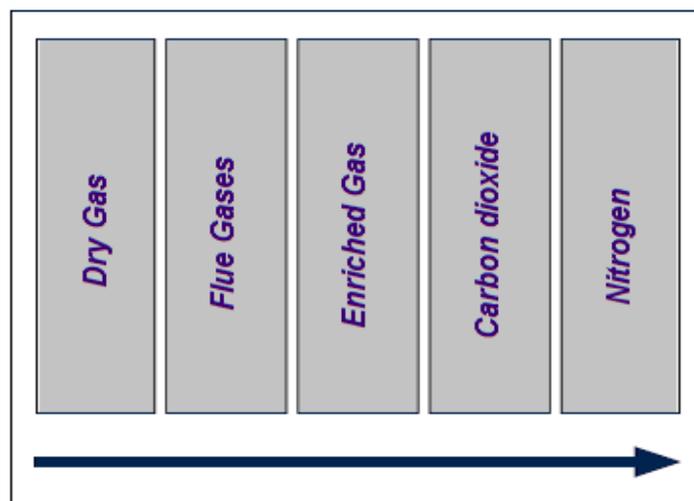


Figure 2. Gas stimulation methods ranked by criteria of applicability on a low-permeability reservoir (best to worst)

The calculations were performed using a commercial hydrodynamic simulator in the compositional modeling option [41, 42]. The models were different in their injected agent composition and well operation modes. As a base case, the field was developed in the depletion mode, which allowed the field to reach the oil recovery factor of 0.063.

There is a characteristic feature of wells operating in a low-permeability reservoir in that they experience a significant drop, more than twice, in production rate already within the first year (Fig. 3).

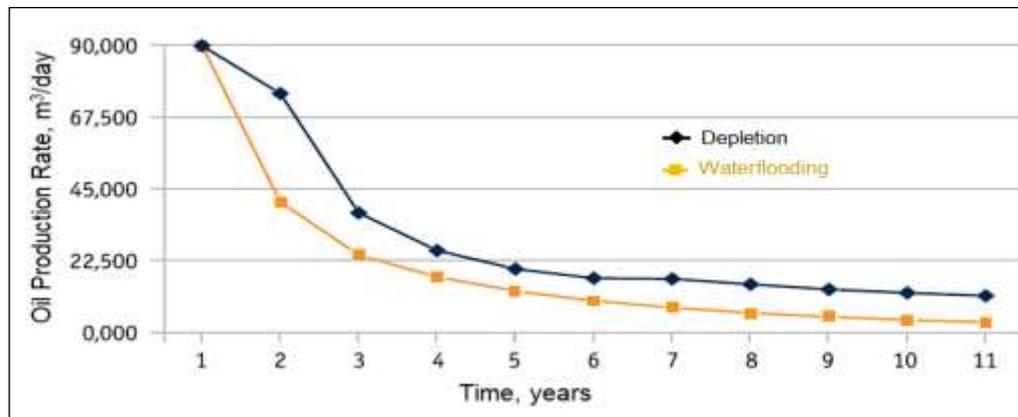


Figure 3. The drop in oil production rates of wells both during the natural mode of development and during water flooding

4. Results and discussions

Based on calculations, there is no way to effectively maintain reservoir pressure with water injection, which takes into account the preparation quality and low reservoir properties (permeability and porosity). In waterflooding, well production rates differed slightly from the dynamics in the natural regime, and the estimated oil recovery factor was 0.109. Due to the implementation of water injection in reservoirs with permeability less than $0.005 \mu\text{m}^2$, oil recovery factor increased by 0.015 unit fraction.

The efficiency of gas injection into a low-permeability reservoir has been calculated based on a compositional model with specified thermobaric conditions [43-45]. For each option, the volume of injected gas was assumed to be the same, except for the option with the re-injection of produced gas, which was based on the amount of oil production. The injection efficiency of each type of gas was evaluated for an equal period, determined by the time it took to reach monotonically decaying dynamics (Fig. 4).

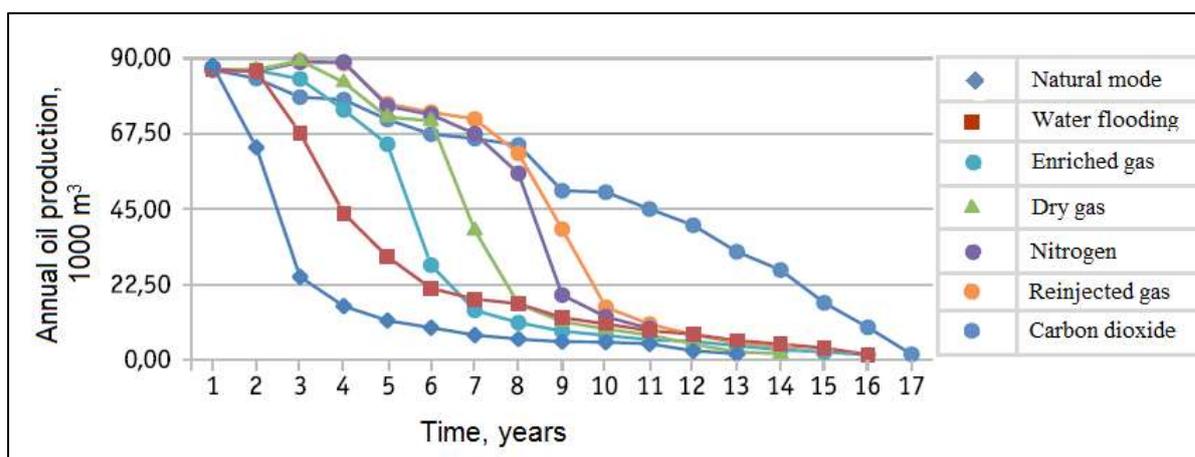


Figure 4. Estimates of annual oil production based on treatment options

In multilayer production facilities, the injection volume is redistributed according to factors such as the physical properties of gas, temperature and pressure conditions, and reservoir properties. In each reservoir, this redistribution will determine the type of displacement and the degree of reservoir

pressure maintenance (RPM) [46-48]. Calculations reveal that increasing propane-butane content in the produced gas by 35% resulted in an increase of oil recovery factor by about 22% when the composition of the gas was changed (from dry to enriched).

As a result of injecting nitrogen, carbon dioxide (CO₂), methane, and enriched gas in all formation layers for 2-4 years, reservoir pressure increased by 5.7 MPa in the upper layer and by 2.0 MPa in the lower layer (Fig. 5).

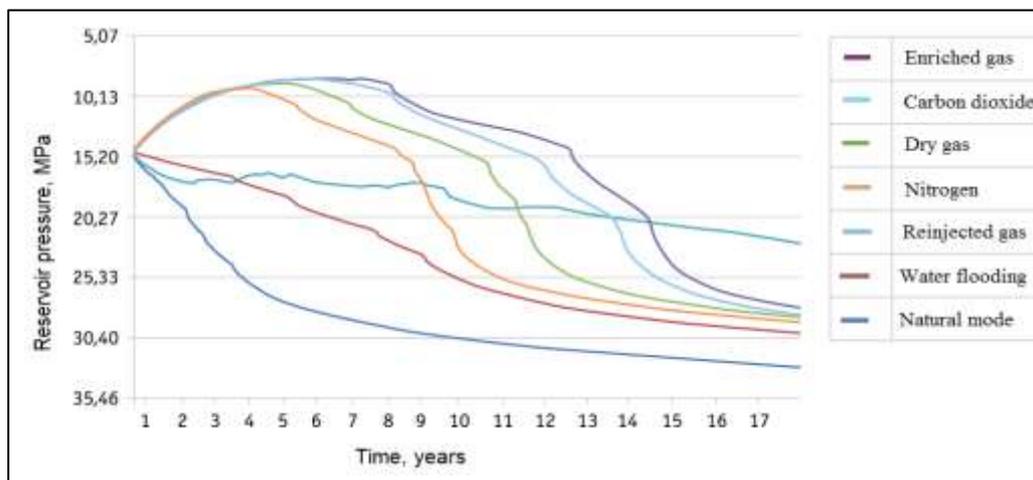


Figure 5. Reservoir pressure dependence on the stimulation option (upper reservoir)

During injection of any gas composition under the given thermobaric conditions (reservoir pressure $P_r = 24.0$ MPa, reservoir temperature $T_r = 100$ ° C) and oil composition, an immiscible displacement pattern is achieved. Miscible displacement is only possible in the upper formation in a limited bottomhole zone when injecting CO₂, enriched, and re-injected gas with a propane-butane mass fraction of 24.8%.

It is observed that reservoir pressure is decreased during re-injection of produced gas and water, as well as during natural depletion. The decrease in reservoir pressure during waterflooding is explained by a low flow rate for reservoirs with a low permeability. During gas re-injection, decreases in reservoir pressure (P_r) are particularly noticeable at the beginning due to limited production volumes. By increasing the development period, the volumes of produced gas will increase, therefore, the volume of injected gas will increase as well.

In the underlying layer, reservoir pressure is maintained at a lower level than in the overlying layer. The calculated oil recovery factor (RF) values are given in Table 1.

Table1. Estimated values of the oil recovery factor

| Method of impact | Oil recover factor, % |
|--------------------------|-----------------------|
| Methane injection | 14.6 |
| Gas re-injection | 22.9 |
| Enriched gas injection | 17.8 |
| Carbon dioxide injection | 16.9 |
| Nitrogen injection | 12.0 |
| Natural mode | 6.3 |
| Waterflooding | 11.4 |

Further, it is important to note that the obtained oil recovery factor values do not only depend on the displacement factors, but also on the volume of penetrated gas in the reservoirs, as well as the possibility and duration of reservoir pressure maintenance, which had a large impact on the change in sweep efficiency [49,50]. Under the studied conditions, re-injection of associated gas was found to be the most technologically efficient working agent.

It is apparent that when implementing gas stimulation methods, not only the composition of the injected gas and injection parameters ought to be determined, but also technological modes of operation of the producing wells for each composition of gas [51 - 53]. Thus, during the re-injection of the produced hydrocarbon gas with an increase in the production rate from 60 to 90 m³ / day, the oil recovery factor increased from 0.190 to 0.229. Further increase in flow rate to 150 m³ / day, however, led to a faster gas breakthrough, a decrease in the share of oil produced, and a decrease in the oil recovery factor to 0.192.

5. Conclusions

When a reservoir has low flow and capacity reservoir properties, with a permeability of less than 0.005 μm², waterflooding cannot be considered as an effective stimulation method. Due to the implementation of water injection in reservoirs with permeability less than 0.005 μm², oil recovery factor increased only by 0.015 unit fraction. Meanwhile, gases of various compositions were found to be more effective as a working agent in reservoirs with permeability less than 0.005 μm². In this case, when changing the composition of the gas (from dry to enriched), increasing propane-butane content by 35% resulted in an increase of oil recovery factor by about 22%.

Therefore and as the primary development method, gas injection is necessary. Which wells are operated and how they are operated must be determined according to the complex geological and geophysical characteristics of the reservoir. In this case, when the hydrocarbon gas was re-injected with an increase in production rates from 60 m³/day to 90 m³/day, the oil recovery factor increased from 0.190 to 0.229. Moreover, injection of different types of gas compositions in all formation layers resulted in reservoir pressure increasing by 2.0 to 5.7 MPa.

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