https://doi.org/10.53656/nat2022-4.02

AN EVALUATION OF WATER AND GAS INJECTIONS WITH HYDRAULIC FRACTURING AND HORIZONTAL WELLS IN OIL-SATURATED SHALE FORMATIONS

Al-Obaidi S. H.[1)], Kamensky I. P.[2)], Hofmann M.[1)], Khalaf F. H.[3)]
[1)] Department of Petroleum Engineering, Mining University (Russia)
[2)] Scientific Research Center, SPB (Russia)
[3)] Department of Petroleum Engineering, Knowledge University, Erbil (Iraq)

Abstract. A variety of methods are examined in this study in order to improve oil recovery from low-permeability heterogeneous reservoirs in oil-saturated shale deposits. Calculations based on the fluid flow model revealed that water and gas injection was effective, and that horizontal and directional wells, including those employing hydraulic fracturing are evaluated in this study. Moreover, hydraulic fracturing in directional wells with vertical completions was found to be one of the most effective methods for water injection in this study. However, when hydraulic fracture length is hard to achieve, the gas injection has been found to be a more efficient way to enhance oil recovery than water injection. Furthermore, horizontal drilling technology was most effective in the central part of the reservoir.

Keywords: gas injection; water injection; hydraulic fracturing; horizontal wells; shale formation

Introduction

The topic of developing hard-to-recover reserves found in low-permeability reservoirs with geological features such as abnormally high formation pressure, lack of bottom waters, and heterogeneity is becoming more and more urgent every day. All these features are typical of oil-saturated shale, which are found in many hydrocarbon deposits around the globe (Al-Obaidi, Patkin & Guliaeva 2003; Sheng 2015; Sheng, Li, Yu et al. 2017; Wang, Torres, Xiang et al. 2015). All of these features affect different aspects of shale oil recovery, including modelling, simulation, and the development of improved recovery methods. In developing such types of reservoirs are widely used hydraulic fracturing along with directional and horizontal wells, however, conclusions about the effectiveness of these two technologies are ambiguous (Al-Obaidi, Smirnov & Kamensky 2019; Li, Su, Guo et al. 2021; Sintsov & Polyakova 2016; Smirnov & Al-Obaidi 2008).

Recent years have seen an increase in the use of water and gas treatment to enhance oil recovery from hard-to-recover oil reserves around the world (Al-Obaidi 2007;

Gamadi, Sheng, Soliman et al. 2014; Hofmann, Al-Obaidi & Khalaf 2022; Shahzad 2014). Furthermore, shale rock formations have recently become an important source of natural gas and oil worldwide. There are many locations where shale gas and oil can be found, including some places where no oil or gas production has ever occurred (Al-Obaidi 2016a; Chang, Al-Obaidi & Patkin 2021; Jia, Tsau & Barati 2019; Mukhina, Cheremisin, Khakimova et al. 2021).

In order to increase oil recovery from oil-saturated shale deposits, this study examines a number of techniques, including hydraulic fracturing, drilling type, well placements, fluid injection, and combinations of some of these.

Methodology

In this article, a model with no bottom water is presented for a low-permeability reservoir. This model was constructed using the stochastic construction method which is based on the binomial law algorithm for a discrete random variable distribution (Fig. 1). The initial data for this model was derived from a real-life field in Western Siberia.

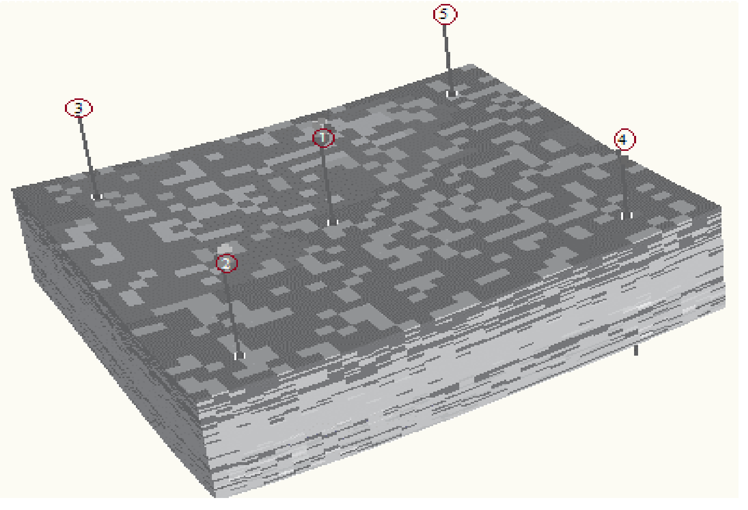

Figure 1. Stochastic geological model for oil shale extraction

A geological object was divided vertically into many elementary layers in this model. In keeping with well logging data, the grid was divided vertically by 0.5 m. At the same time, each interval is classified by its lithological type of rocks. The total number of model cells is 125200. Based on a stochastic geological model, a digital flow model is developed. The geological modelling was performed using the Irap RMS software package (Afanasyev 2015; Al-Obaidi 2016b; Edwards, Dhanpat, Prasad et al. 2018). Hydrodynamic calculations were performed using the Tempest More software package. To calculate oil, gas, and water flow in porous mediums (Black Oil), a three-dimensional, three-phase, isothermal hydrodynamic model was used, which is the most commonly used model for oil field development (Al-Obaidi, Galkin, & Patkin 2006; Al-Obaidi & Khalaf 2019; Qian, Lu, Wang et al. 2022; Wang, Torres, Xiang et al. 2015).

The petroleum shale is characterized by low porosity (10 – 15%) and fairly low permeability (1 – 20 md). Moreover, oil conditions under reservoir are low viscosity (1.1 mPa*s), low density (820 kg/m^3), and bubble point pressure of 10 MPa, which is much lower than that of the reservoir.

In Figure 2, a graph depicting water and oil permeability is constructed based on reservoir pressure and temperature. As can be seen, the residual oil saturation is 0.6 fractions of units (by this point, the relative permeability of the oil becomes zero), which makes the process of extracting hydrocarbons more challenging. The object selected for modelling is a part of a reservoir with dimensions 1500 by 1500 meters and a production well positioned in the centre. As part of the reservoir pressure maintenance system (RPMS), four injection wells were added to the model according to a five-spot pattern (Davies & Silberberg 1968; Hofmann, Al-Obaidi & Kamensky 2021; Sun, Liu, Wang et al. 2020) at equal spacing from the central well, with a grid density of 25 ha per well. In the design, the wells were expected to last 30 years. The following conditions must be met for shutting down wells: at least 98% water cut and less than 1 ton of oil produced per day. In the considered model, there is no anomalously high reservoir pressure (AHRP) and the average reservoir top depth is 3000 meters. This reservoir is lithologically shielded.

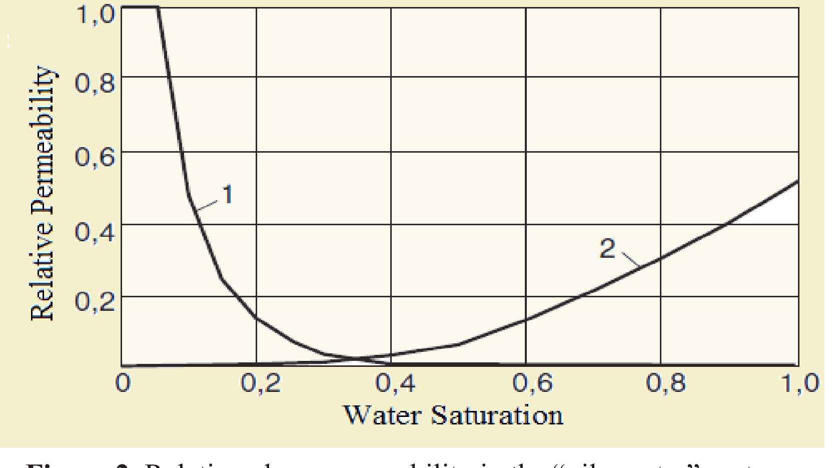

Figure 2. Relative phase permeability in the “oil - water” system: 1 and 2 – saturations of oil and water, respectively

Recently, a discussion regarding the potential for using certain technologies for more efficient oil shale development in Western Siberia was held (Al-Obaidi, Smirnov & Khalaf 2020; Sintsov 2014). Among the proposed technologies for increasing oil recovery, one can highlight the creation of reservoir pressure maintenance systems, which involve the injection of water or gas, as well as hydraulic fracturing and the use of horizontal wells. In practice, some methods are experimental in nature, and so far, no universal method has been found to develop reservoirs of this type (Mahzari, Jones & Oelkers 2020; Sheng, Li, Yu et al. 2017; Waburoko, Xie, & Ling 2021). In order to evaluate the effectiveness of these technologies and compare them with each other, both individually and in combination, several development options were considered:

1. in natural mode;
2. with formation pressure maintained by injection of water;
3. with formation pressure maintained by injection of gas;

In the gas injection process, carbon dioxide (CO_2) was selected as the displacing agent. Oil displacement is best performed with this gas, even when comparing it to associated gas. Presently, CO_2 injections are being introduced commercially at certain fields in Western Siberia.

In each of the options, several sub-options of well types with different locations in the reservoir were considered:

1. a well with a vertical reservoir opening (hereinafter a directional well, DW);
2. a well with a vertical reservoir opening and hydraulic fracturing (hereinafter a directional well (DW) with hydraulic fracturing (HF);
3. a well with a horizontal reservoir opening in the upper part (UP), 300 m long (hereinafter a horizontal well (HW) in the upper part, top);
4. a well with a horizontal reservoir opening in the bottom part (BP), 300 m long (hereinafter HW in the bottom);
5. a well with a horizontal reservoir opening in the central part (CP), 300 m long (hereinafter HW in the centre).

Results and discussions

As a result of developing the deposit in a natural mode, low indicators of cumulative oil production were obtained (Fig. 3).

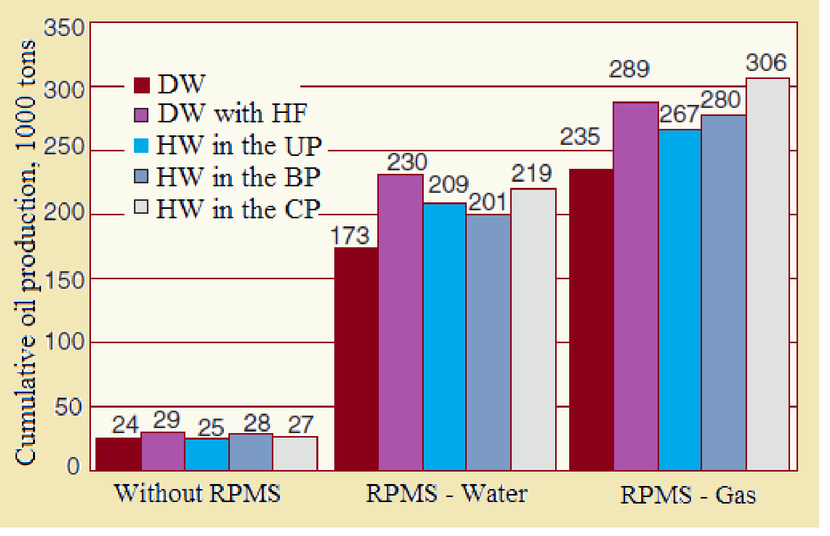

Figure 3. Results of hydrodynamic modelling

All types of modelled wells experience a rapid decline in production rates in the course of operation. The oil production rate drops to less than 1 t/day after three to four years in all cases. Because the reservoir under consideration has a lenticular arrangement, and there is no bottom water to maintain its energy characteristics, the object is rapidly losing energy. In directional wells, the longest periods of operation are achieved; however, the use of hydraulic fracturing in directional wells results in a maximum cumulative production of 29 thousand tons, which is 20% higher than in directional wells without hydraulic fracturing. In horizontal drilling, the best performance is characterized by a well with a wellbore located at the bottom of the formation. However, it should be recognized that the technologies under consideration are characterized by relatively low efficiency.

Oil recovery is significantly increased in all cases when reservoir pressure is maintained through water injection. In comparison to the natural regime, cumulative oil production increases by at least seven times. By using hydraulic fracturing in the directional wells, oil production can be increased by 33% and it is a more effective method than horizontal drilling, allowing 230 thousand tons of oil to be produced cumulatively. Among the horizontal wells considered, the least effective is the one located at the bottom of the reservoir since water penetrates it more quickly during waterflooding than the wells located in the centre and the top. It is important to note, however, that if a horizontal well (HW) is operated in the upper part of the reservoir, the reserves below the HW are less productive since the reservoir object has a high level of layered heterogeneity.

Gas injections for maintaining reservoir pressure have shown good results, since the reservoir under consideration is characterized by high residual oil saturation. The use of carbon dioxide gas can significantly increase oil recovery. Due to the higher permeability and mobility of this gas in comparison with the formation fluids, as well as its lower density, the upper part of the reservoir experiences faster gas displacement than the lower part. CO^2 injection increases total oil production in directional wells by 36% when compared to water injection, and by almost ten times when compared to natural oil production. At the same time, based on calculations, the most effective is the use of a horizontal well in the center of the reservoir. A cumulative oil production of 306 thousand tons was achieved in this way. This is a more efficient technology compared to hydraulic fracturing, since the entire oil-saturated interval is opened during hydraulic fracturing, and the probability of gas leaking into the fracture is higher than in a horizontal well. Furthermore, this would also explain the relatively low oil production of horizontal wells in the top when compared to other well configurations. After the breakthrough of gas in the upper intervals, the levels of oil production are significantly reduced. Additionally, the location of the well within the formation, whether at the top or bottom, has a negative impact on the production coverage along the section.

Conclusions

In this study several methods are modelled and evaluated to increase the oil recovery from oil-saturated shale deposits. Several conclusions can be drawn from the analysis of the results.

The development of hard-to-recover reserves in low-permeability heterogeneous reservoirs, typical for oil-saturated shale, is unpromising in the absence of a reservoir pressure maintenance system. In terms of injecting water, hydraulic fracturing in directional wells with vertical completion has been shown to be one of the most promising methods. However, in practice, it is not always possible to achieve the design fracture length, which can lead to a deterioration of real-life performance. In this type of reservoir, gas injection is a more efficient way to enhance oil recovery than water injection. The horizontal drilling technology in the central part of the reservoir proved most effective. However, the successful application of horizontal wells largely depends on specific geological conditions, which cannot be assessed with high reservoir heterogeneity.

REFERENCES

AFANASYEV, A., 2015. Hydrodynamic modelling of petroleum reservoirs using simulator. *Energy Procedia*. **76**, 427 – 435.

AL-OBAIDI, S. & KHALAF, F., 2019. Development of traditional water flooding to increase oil recovery. *International Journal of Scientific & Technology Research.* **8**(1) 177 – 181.

AL-OBAIDI, S. H., PATKIN, A. A. & GULIAEVA, N.I., 2003. Advance use for the NMR relaxometry to investigate reservoir rocks. *JoPET*. **2**(3), 45 – 48.

AL-OBAIDI, S., 2007. Analysis of hydrodynamic methods for enhancing oil recovery. *Journal of Petroleum Engineering and Technology*. **6**(3), 20 – 26.

AL-OBAIDI, S., 2016a. High oil recovery using traditional water-flooding under compliance of the planned development mode. *Journal of Petroleum Engineering & Technology*. **6**(2), 48 – 53.

AL-OBAIDI, S., 2016b. Improve the efficiency of the study of complex reservoirs and hydrocarbon deposits – East Baghdad field. *International journal of scientific & technology research*. **5**(8), 129 – 131.

AL-OBAIDI, S., GALKIN, A. & PATKIN, A., 2006. Prospects of high viscosity oil flow rate in horizontal wells. *JoPET*. **5**(4), 56 – 62.

AL-OBAIDI, S., SMIRNOV, V. & KAMENSKY, I., 2019. Investigation of rheological properties of heavy oil deposits. *International Journal of Scientific & Technology Research*. **8**(9), 2394 – 2397.

AL-OBAIDI, S., SMIRNOV, V. & KHALAF, F., 2020. New technologies to improve the performance of high water cut wells equipped with ESP. *Technium*. **3**(1), 104 – 113.

CHANG, W. J., AL-OBAIDI, S. H. & PATKIN, A. A., 2021. The use of oil-soluble polymers to enhance oil recovery in hard to recover hydrocarbons reserves. *International Research Journal of Modernization in Engineering Technology and Science*. **3**(1), 982 – 987.

DAVIES, L. G., & SILBERBERG, I. H. 1968. A method of predicting oil recovery in a five-spot steam flood. *J Pet Technol*. **20**, 1050 – 1058. doi: https://doi.org/10.2118/1730-PA.

EDWARDS, L., DHANPAT, D., PRASAD, D., et al., 2018. Hydrodynamics of three phase flow in upstream pipes. *Cogent Engineering*. **5**(1). doi: 10.1080/23311916.2018.1433983.

GAMADI, T. D., SHENG, J. J., SOLIMAN, M. Y. et al., 2014. An experimental study of cyclic CO_2 injection to improve shale oil recovery. *SPE Improved Oil Recovery Symposium, Tulsa, Oklahoma, USA*, 12 – 16 April.

HOFMANN, M., AL-OBAIDI, S. H. & KAMENSKY, I. P., 2021. Calculation method for determining the gas flow rate needed for liquid removal from the bottom of the wellbore. *J Geol Geophys*. **10**(5), 1 – 5.

HOFMANN, M., AL-OBAIDI, S. H. & KHALAF, F. H., 2022. Modeling and monitoring the development of an oil field under conditions of mass hydraulic fracturing. *Trends in Sciences*. **19**(8): 3436.

JIA, B., TSAU, J. S. & BARATI, R., 2019. A review of the current progress of CO_2 injection EOR and carbon storage in shale oil reservoirs. *Fuel*. **236**, 404 – 427.

LI, G., SU, Y., GUO, Y. et al., 2021. Frontier enhanced oil recovery (EOR) research on the application of imbibition techniques in high-pressure forced soaking of hydraulically fractured shale oil reservoirs. *Geofluids*. Article ID: 6634357, https://doi.org/10.1155/2021/6634357.

MAHZARI, P., JONES, A. P. & OELKERS, E. H. 2020. Impact of in-situ gas liberation for enhanced oil recovery and CO_2 storage in liquid-rich shale reservoirs. *Energy Sources, Part A: Recovery, Utilization, and Environmental Effects*, doi: 10.1080/15567036.2020.1815907.

MUKHINA, E., CHEREMISIN, A., KHAKIMOVA L., et al., 2021. Enhanced oil recovery method selection for shale oil based on numerical simulations. *ACS Omega.* **6**(37), 23731 – 23741 doi: 10.1021/acsomega.1c01779.

QIAN, Q., LU, M., WANG, F., et al., 2022. Simulation of oil-water flow in shale oil reservoirs based on smooth particle hydrodynamics. *Fluid Dynamics & Materials Processing*. **18**(4), 1089 – 1097.

SHAHZAD, Y., 2014. Evaluation of the enhance oil recovery (EOR) potential of water and gas injection in oil shale reservoirs. http://dx.doi.org/10.2139/ssrn.2478558.

SHENG, J. J., 2015. Enhanced oil recovery in shale reservoirs by gas injection. *Journal of Natural Gas Science and Engineering*. **22**, 252 – 259. https://doi.org/10.1016/j.jngse.2014.12.002.

SHENG, J., LI, L., YU, Y. et al., 2017. Maximize liquid oil production from shale oil and gas condensate reservoirs by cyclic gas injection. *United States*. https://doi.org/10.2172/1427584. https://www.osti.gov/servlets/purl/1427584.

SINTSOV, I. A. & POLYAKOVA, N. S., 2016. Analysis of the effectiveness of water-gas impact, taking into account saturation pressure in the conditions of the Upper Jurassic deposits. *Territory NEFTEGAS* (4) 40 – 45. [in Russian].

SINTSOV, I.A, 2014. Comparison of geological and technical measures effectiveness for the Upper Jurassic conditions of western Siberia. *Paper presented at the SPE Russian Oil and Gas Exploration & Production Technical Conference and Exhibition, Moscow, Russia*. doi: https://doi.org/10.2118/171231-MS.

SMIRNOV, V. & AL-OBAIDI, S., 2008. Innovative methods of enhanced oil recovery. *Oil Gas Res* 1: e101. doi: 10.4172/2472-0518.1000e10.

SUN, K., LIU, H., WANG, Y. et al., 2020. Novel method for inverted five-spot reservoir simulation at high water-cut stage based on time-varying relative permeability. *ACS Omega*. **5**(22), 13312 – 13323. doi: 10.1021/acsomega.0c01388.

WABUROKO, J., XIE, C. & LING, K., 2021. Effect of well orientation on oil recovery from waterflooding in shallow green reservoirs: a case study from Central Africa. *Energies*. **14**(5), 1223; https://doi.org/10.3390/en14051223.

WANG, L., TORRES, A., XIANG, L., et al., 2015. A technical review on shale gas production and unconventional reservoirs modeling. *Natural Resources*. **6**(3), Article ID: 54430, doi 10.4236/nr.2015.63013.

✉ **Prof. S. H. Al-Obaidi, DSc.**
ORCID ID: 0000-0003-0377-0855
Department of Petroleum Engineering
Mining University, Russia
E-mail: drsudad@gmail.com

✉ **Prof. I. P. Kamensky, DSc.**
ORCID iD: 0000-0001-7254-4021
Scientific Research Center
SPB, Russia
E-mail: kamensky962@gmail.com

✉ **Dr. F. H. Khalaf, Assist. Prof.**
ORCID iD: 0000-0002-1419-4630
Department of Petroleum Engineering
Knowledge University
Erbil, Iraq
E-mail: falhkh@yahoo.com

✉ **Prof. M. Hofmann, DSc.**
ORCID iD: 0000-0001-5889-5351
Department of Petroleum Engineering
Mining University, Russia
E-mail: hof620929@gmail.com