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Article

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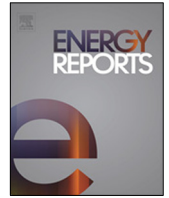
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Research paper

A simulation study to control the oil production rate of oil-rim reservoir under different injectivity scenarios

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ABSTRACT

Drilling thin oil layers regarding the high expenditures is always considered as the debate issue in petroleum industries to invest. Oil rim reservoirs are one kind unconventional reservoirs which are occupied with a strong aquifer and a big gas cap that provided complex conditions for producing reserve oil. The purpose of this study is to simulate the six different injectivity scenarios for one of the Iranian's oilfield to select the optimum scenario which has the most oil production. In these injectivity scenarios, different gas–oil ratios, water cut, and drilling new wells were considered in the simulator to compare each of them in more detail. Consequently, scenario 6 has the optimum volume of field oil production regarding the drilling of one horizontal well and three vertical well. That is to say that, horizontal wells due to the higher contact with the thin oil layers have led to more oil production rate and it is recommended to drill the wells in this type of reservoir horizontally.

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1. Introduction

Oil rim reservoirs are considered as one of the unconventional reservoirs with the pay zone of fewer than 100 ft that is occupied by a gas cap and an aquifer. In this type of reservoirs, the gas and water coning phenomena are being considered as the debating and challengeable issues especially in the production procedure. According to the arrangement of gas cap layer on the oil layers, the schematic of oil rim reservoirs is categorized as the pancake or doughnut structure in which the mobility alteration between the current phases in the system lead to mobilize the oil phase to the production wells (Augustine et al., 2017; Cosmo and Fatoke, 2004; Owolabi and Ogungbamigbe, 2017; Song et al., 2017; Tiefenthal, 1994; Tiong-Hui and Cheng, 2018; Zifei et al., 2018) (see Fig. 1).

In this types of reservoirs, the main purpose of field development is to produce the maximum volume of reserves and subsequently achieving the optimum oil recovery factor with the minimum expenditures. Providing this condition for oil rim reservoirs with the huge gas cap and a strong aquifer might be challenging. Therefore, to have a successful project in these reservoirs, it is required to produce the maximum volume of reserve oil before the construction of the gas cap above the oil layer. The mechanism of production-injection of an oil rim reservoir is approximately complex due to the percolation occurrence of three phase of oil, water, and gas. The reason of this complexity is related to the crude oil degassing, water injectivity, retrograde condensation

(Davarpanah, 2018; Davarpanah et al., 2018; Mjaavatten et al., 2006; Mohd Ismail et al.; Ogiriki et al., 2018; Ogolo et al., 2017; Olabode et al., 2018; Siddhamshetty and Kwon, 2018). The principal driving mechanisms of oil rim reservoirs are gas cap expansion, solution gas expansion, and viscous withdrawal. Hence, the equivalence of these mechanisms in the oil rim reservoirs would be a significant parameter to stabilize the oil rim construction. Reinjection of produced gas has caused to the pressure drop control in the well, and other parts of the reservoir that this equivalence is profoundly impacted by the strengthens of the aquifer, the location, distance of proposed oil layer, and the well perforation. Thereby, this equivalency has led to the oil stabilize and avoided its mobilization (Augustine et al., 2017; Cosmo and Fatoke, 2004; Elmsallati et al., 2005; Fernie et al., 2018; Ferrero et al., 2017; Fouzdar et al., 2017; Lawal et al., 2010; Mammadov et al., 2017; Masoudi et al., 2013; Razmjoo et al., 2017).

Despite the challenging circumstances of oil rim reservoirs and unprofitable economic climate of these reservoirs, there are few studies to investigate and analyze the recovery techniques in oil reservoirs. The main objective of this study is to propose six different simulated injectivity scenarios with ECLIPSE simulator with different conditions to choose the optimum scenario before performing the drilling operations. Thereby, drilling newer wells especially horizontal wells would prefer for this type of unconventional reservoirs because the drilled wells have higher contact with the oil layers.

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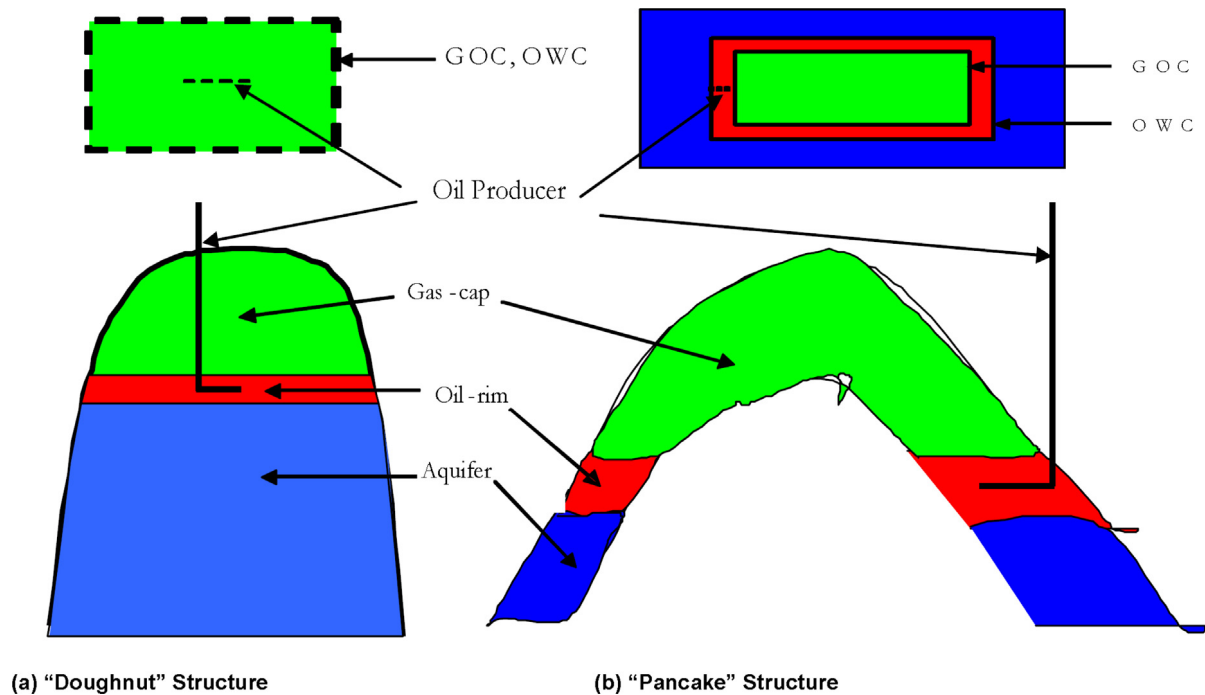


Fig. 1. Schematic of two ideal types of oil rim reservoirs (Lawal et al., 2010).

Table 1

Petrophysical properties of the reservoir.

Petrophysics property	Average initial value
Initial reservoir pressure (bar)	2147
Reservoir temperature (°F)	140
Formation compressibility (bar^{-1})	$3\text{E}-05$
Average water saturation (%)	52
Bubble point pressure (bar)	1921
Gas gravity	0.91
Oil gravity	0.82
Reservoir water pressure (bar)	2367

2. Reservoir characteristics

The oil rim reservoir which is taken into consideration in this simulation is located in the southwest of Iran with the height of 30 km and the longitudinal weight of 10 km. According to the National Iranian Oil Company datasheet, the crude oil of this reservoir is considered as light crude oil with the API number of more than 40 °API. Moreover, the average initial temperature and pressure of this reservoir is 141 °F and 2147 bar respectively at the datum depth of 600 m. Petrophysical properties of the reservoir are statistically explained in Table 1. To be more accurate, all of the petrophysical properties of the reservoir were taken into the average value to eliminate the discrepancies of the reservoir virtually.

Regarding the evaluations of petrophysical logs, perforation circumstances, and the history matching of production wells, oil-water contact is measured about 370 m under the surface. Fractures dispersion of the rock is being modeled in ECLIPSE by the surrounding circular technique to distinguish the types of fractures which are clearly illustrated the reservoir permeability in each section. The schematic of fractures dispersion in the studied field is depicted in Fig. 2.

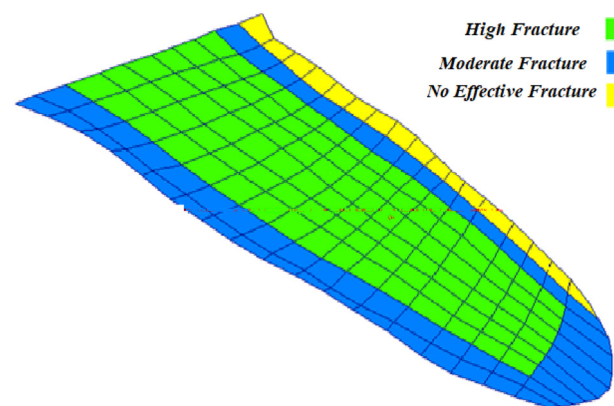


Fig. 2. Fracture dispersion in the studied field.

3. Simulation analysis by ECLIPSE software

Due to the petrophysical properties of the studied oilfield, a black oil model was defined in the ECLIPSE 100 software to compare the six injectivity scenarios. The Static model of the field along is depicted in Fig. 3. In this model, the volume of primary gas was assumed of 700 000 million cubic feet and 600 million barrels of oil. After the construction of the geological model in the software, a network with the dimensions of $NX = 17$, $NY = 10$, and $NZ = 23$ with the total cells of 3910 was defined in the software (each cell in the network mesh has the approximate dimension of 400×700 m). Regarding the reservoir fractures, the proposed model should be defined as the dual porosity model in which the fracture properties were defined separately in the software. In respect of the way, the constructed model has contained 4,6 layers (layers 23–46 were related to the fractures), and the total number of cells is equal to 7820 cells.

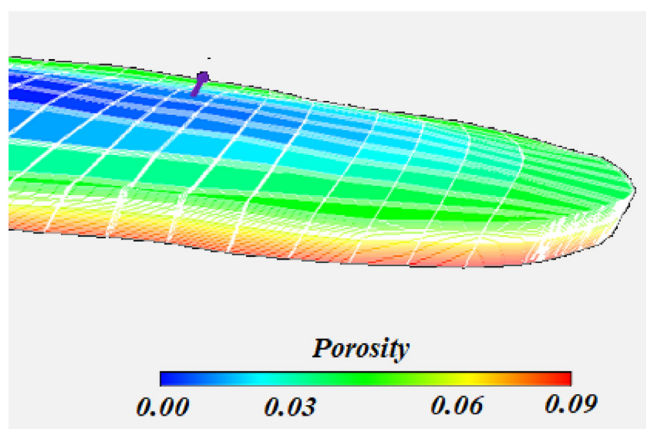


Fig. 3. The static model of the studied field.

PVTi module is used to analyze the petrophysical properties of the reservoir such as relative permeability by the administration of Corey correlation. The relative permeability curves of water–oil contact and gas–oil contact for each injectivity scenario are schematically plotted in Figs. 4 and 5. As can be seen in Fig. 4, when oil and water were in contact in the reservoir condition, the relative permeability of the oil phase had the maximum value in the low water saturation, and it had decreased gradually by the increase of water saturation. It had reached zero in the water saturation of 75–80, and it is the evidence of no oil production in this stage. Thereby, it is witnessed that in the lower water saturation, oil droplets could be able to mobilize more in the reservoir and caused to higher relative permeabilities. According to the results of Fig. 4, the relative water permeability had a reserved pattern rather than oil relative permeability. Therefore, water relative permeability was about zero in the lower water saturation. Since then, it had increased dramatically in the water saturation of 50–75 percent. As a result, the higher water relative permeability had caused to higher production of water which is of elaborated as the lower oil production. Relative permeabilities in the contact of oil–gas phase is a little different with water–oil contact. As it can be seen in Fig. 5, oil relative permeability was about zero up to reaching the water saturation to the 80 percent. Next, it had increased by the rise of water saturation for each well up to reach a stable oil relative permeability to 0.6. On the other hand, gas relative permeability had witnessed a diverse pattern than oil relative permeability. It has its maximum value in the lower water saturation (it is about 0.15), and after that, it had been decreased gradually by the rise of water saturation. Thereby, in the higher water saturation, the gas relative permeability had reached zero.

3.1. History matching

In this study, by simulating different injectivity models, we try to adopt the simulated models with the real field data. In respect of the way, by the alteration of matching parameters in the acceptable limit and fix them in the simulator, the oil production history and field pressure are being modeled for well number 1. These parameters contain fracture transfer coefficient, DZMATRIX, porosity, SIGMA, and absolute permeability. The logical limits for the history matching are as the following assumptions;

- The acceptable pressures for the matching would be differentiated in the range of 50 psia lower or higher the actual field pressure.
- Adaptation of field oil production rate and simulated oil production rate should be in a good agreement to estimate the plans properly.

- The water quality in the field conditions and the simulator would be approximately in a good agreement.

History matching was done for the well no. 1 in this field to validate the simulation results with the experimental observations. As it is evident in Fig. 6, in the first years of production from the reservoir, the oil production rate had fluctuated sequentially, and it was approximately stabilized in the year 1993. This stabilization was about three years, and it was decreased in the upcoming years. It was reached a plateau; it was about 2000 STB/Day. According to the simulation and experimental results, the history matching had shown a good agreement with them. Thereby, the good agreement with both techniques corresponded to the accuracy of the simulated model.

Pressure drop for this well is not changing enough; it had decreased gradually in 14 years. It was decreased about 100 bar in the production period. According to the simulated results and experimental observations, real field pressures fluctuated a bit slow in this period, and the adaptation of these pressure values illustrate the accuracy of the simulated model. It is schematically plotted in Fig. 7.

Filed water cut is plotted in Fig. 8 to compare with field oil production rate. As it is evident, in the first years of production, the water cut is high enough which might be caused by a strong aquifer. It had the maximum value of 0.045 in the year 1992. Since then, it has decreased dramatically in the next two years to reach the zero. After that, it was increased drastically between the years 1994–1998 which might be caused by the water flooding in this period. Next, it gradually rose in the following years. Therefore, it is clear that in this well, the rate of water cut is high enough which should be taken into consideration to propose this issue in the simulated performances.

4. Result and discussion

Injectivity scenarios were included five scenarios with different conditions to provide a comparative analysis with them and choose the optimum characteristics. The following assumptions were considered in the simulator to calculate the field oil production rate (FOPR), field gas production rate (FGPR), field water production rate (FWPR), and pressure drop. Oil productivity rate for all the injectivity scenarios are assumed 4000 STB/Day, and there were three production wells was considered for all the scenarios in the simulator. Other parameters for each scenario are explained in more detail in the following assumptions;

- Scenario one; gas–oil ratio (henceforth; GOR) was 850 SCF/STB, the water cut was 10%, and there is no new drilled vertical well.
- Scenario two; GOR = 1050 SCF/STB, the water cut was 10%, and there is no new drilled vertical well.
- Scenario three; GOR = 1050 SCF/STB, the water cut was 10%, and there is one new drilled vertical well.
- Scenario four; GOR = 1050 SCF/STB, the water cut was 26%, and there is one new drilled vertical well.
- Scenario five; GOR = 1050 SCF/STB, water cut was 26%, and there are two new drilled vertical wells.
- Scenario six; GOR = 1050 SCF/STB, water cut was 26%, and there are three new drilled vertical wells and one horizontal well.

4.1. Comparative analysis of FOPR

The simulation procedure was started in 2001 for the six decades of production. As it is evident in Fig. 9, in the first decade of injection (2001–2010), there is a sharp increase in the field oil production rate which is regarded as the sequential injection of water

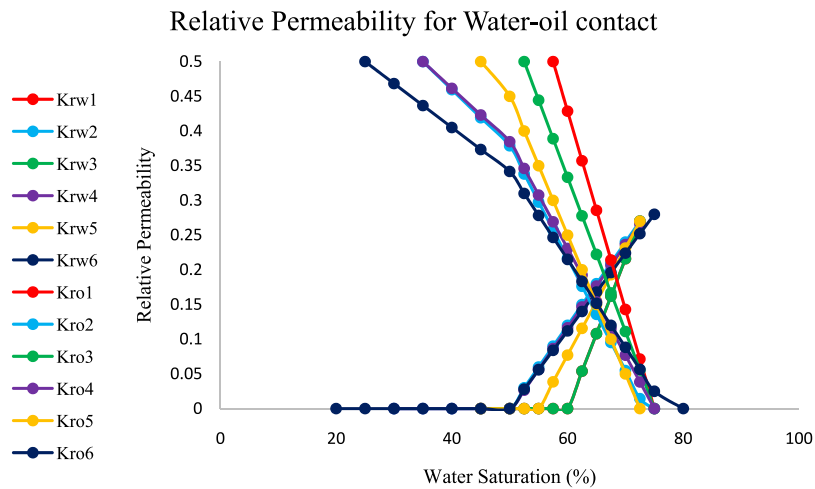


Fig. 4. Relative permeability for water–oil contact.

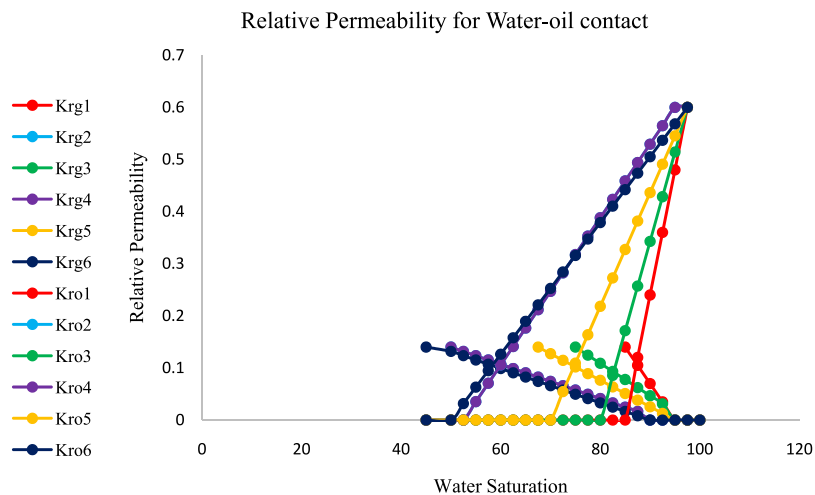


Fig. 5. Relative permeability for gas–oil contact.

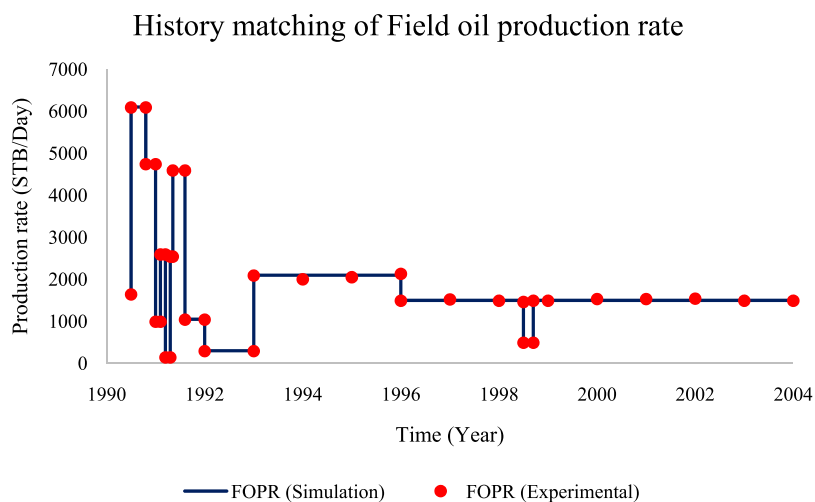


Fig. 6. History matching of field oil production rate.

flooding and gas flooding in this decade. However, the maximum oil production in the sequential injection of water flooding and gas flooding processes was about 9350 STB/Day for all the scenarios; the oil production rate was decreased in the upcoming decades.

Due to the alteration of injectivity parameters in the simulator, there is not a significant rise in the oil production for scenario 1 and 2. It had reached its minimum value in the last decades of injectivity. In scenarios 3–5, regarding the drilling new wells,

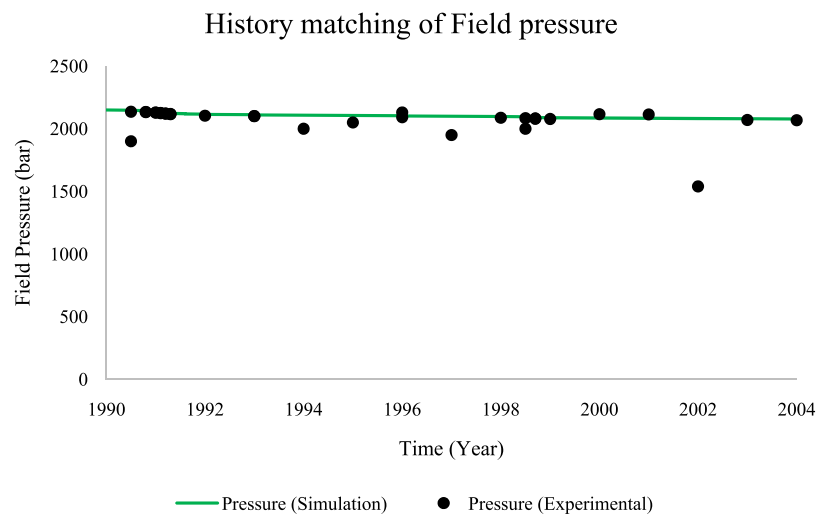


Fig. 7. History matching of field pressure.

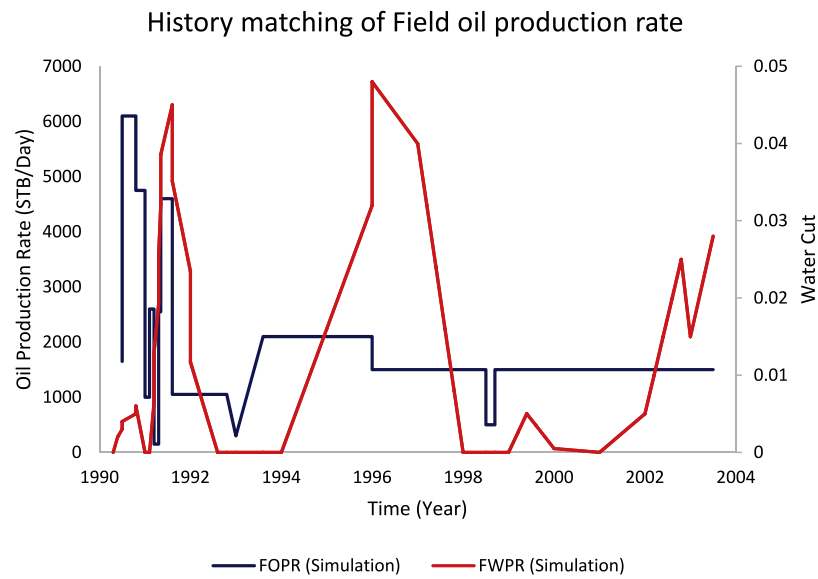


Fig. 8. Field oil production & water cut (calculated).

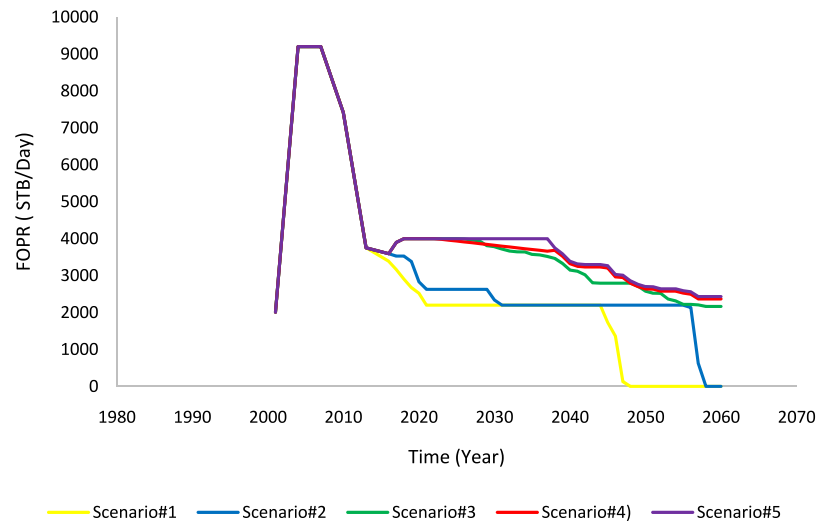


Fig. 9. Simulated field oil production rate versus time.

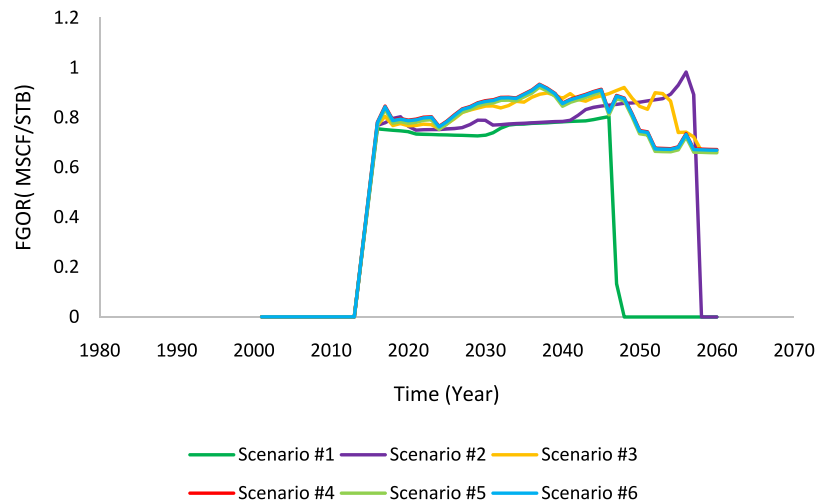


Fig. 10. Simulated field gas-oil ratio versus time.

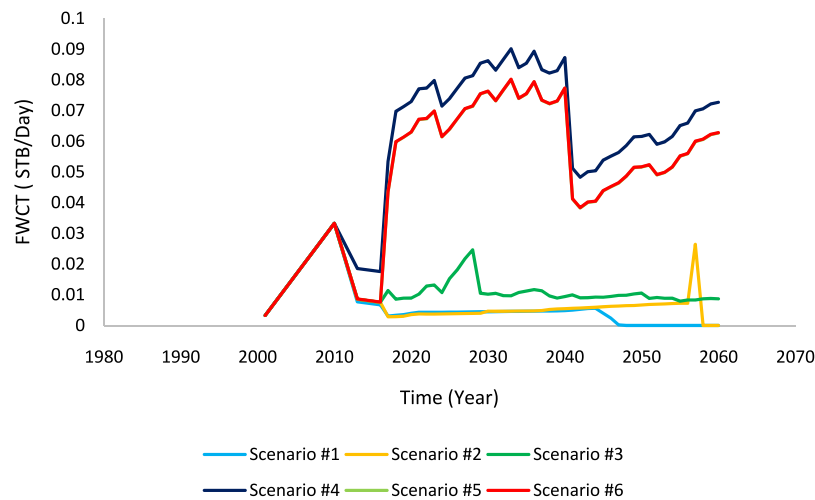


Fig. 11. Simulated field water cut total versus time.

the simulated wells had experienced a gradual decrease in the next decades which was indicated the considerable influence of newly drilled wells on the oil production. Thereby, among injectivity scenarios of 3–5, scenario five due to the number of newly drilled wells had provided more oil production volume in the upcoming decades and had decreased less. In the step of injectivity performances, a new horizontal well was added in the simulation processes in the length of 2075 ft. Horizontal wells regarding their higher contacts with the oil layers were provided the more oil production. Thereby, in comparison with other scenarios, drilling horizontal wells would cause to the more oil production rate, and scenario six was considered as the optimum scenario especially for oil rim reservoirs that has thin oil layers.

4.2. Comparative analysis of FGOR and FWCT

The production of the gas phase is inevitable in the recovery processes due to the high mobility of gas in the pores than oil. As can be seen in Fig. 10, for all the injectivity scenarios, in the first decade of production (2001–2010), the gas-oil ratio had an extremely low volume which was negligible. It has risen dramatically in the next decade and reached its maximum value of 0.85 MSCF/STB which might be caused by the sequential injection of water and gas in the reservoir. Next, it had fluctuated for three decades. Thereby, drilling new wells have caused a lower gradual

decrease in the FGOR in the injectivity scenarios of 3–6. Furthermore, the field water cut for each scenario was schematically shown in Fig. 11.

4.3. Pressure drop

By passing the production time in the recovery procedures, pressure has been decreased; in the first decades of production, the pressure value had a stable pattern and did not have a significant decline. After that, it had decreased slightly for all the injectivity scenarios, but this phenomenon is a bit slowly for scenario 5 and six regarding the drilling newer wells which provides less pressure drop rather than other scenarios. It is shown in Fig. 12.

5. Conclusions

Enhanced oil recovery of unconventional reservoirs such as oil rim reservoirs has always considered as the main concerns of petroleum industries regarding the small thickness of oil layers in which some of these reservoirs were abandoned due to the less economic prosperity of oil rim reservoirs. The purpose of this study is to simulate six different injectivity scenarios for one of the oil rim reservoirs to compare each scenario and select the optimum scenario. According to the results of this study, scenario six regarding the drilling of one horizontal well which has caused

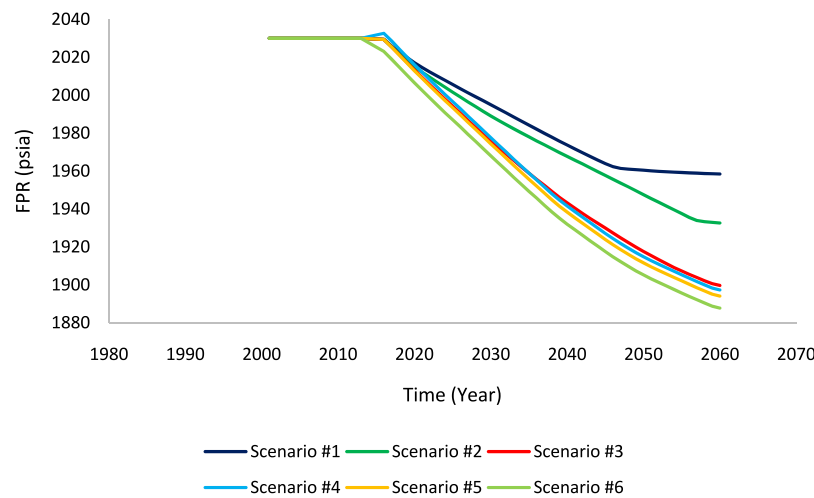


Fig. 12. Simulated field pressure ratio versus time.

to have more contact with the oil layers and three vertical wells had the most field oil production rate and preferred for the future drilling operations.

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