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INVESTIGATION, SENSITIVITY ANALYSIS AND COMPARISON OF THE OIL RECOVERY COEFFICIENTS IN DIFFERENT ENHANCED OIL RECOVERY SCENARIOS

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Abstract

Water and gas injection to oil fields is one of the important enhanced oil recovery methods, which leads to decrease reservoir pressure drop and increased production. In this work, sensitivity analysis have been carried out in order to study more carefully the performance of the reservoir on parameters such as vertical to horizontal permeability ratio, volume of aquifer to original oil in place ratio, number of wells and the wettability of reservoir rock and its effect on reservoir recovery factor to select the best scenario. In addition, the different scenarios of natural depletion, water injection, gas injection and water-gas injection into reservoirs have been modeled using ECLIPSE100 simulation software and the results of simulations have been compared. The results show that water - gas injection method improves the sweep efficiency and thus delays the delivery time of the injected fluid to the production wells and leads to the decreased mobility in different parts of the reservoir and prevents channeling of the injected fluid. This method generally performs better compared with the water injection method considering the type of wettability of the reservoir rock and increases the recovery factor by 4%.

Keywords: *Enhanced production; Simulation; Sensitivity analysis; Water injection; Gas injection; Water-gas injection.*

1. Introduction

Generally, the objective of water and gas injection into oil reservoirs is enhancement of oil recovery factor from the reservoirs and providing the capacity for the conversion of original oil in place to recoverable oil. According to the estimations made, most of the oil produced from oil fields, which are in the second half of their lives. Therefore, the implementation of enhanced recovery projects in such fields seems necessary. Song *et al.* [1] investigated the effect of operational schemes, reservoir types and development parameters on both the amount of incremental oil produced and CO_2 stored in high water cut oil reservoirs during CO_2 water-alternating-gas (WAG) flooding by running compositional numerical simulator. Tavousi *et al.* [2] presented a comparison of enhanced heavy-oil recovery by three methods (CGI, WAG, and GAGD) is conducted by a commercial numerical simulator.

In carbonate oil fields, the application of natural gas injection method can be considered an appropriate choice for enhanced recovery from these reservoirs. Gas injection into oil fields has always been associated with problems due to the lack of natural gas and high gas consumption. Therefore, other enhanced recovery methods ought to be considered and combined methods must be used in different fields. In general, the mobility ratio of the injected gas to the moving oil can cause finger phenomenon and thus reduced movement due to the lower viscosity of the gas [3-4]. In water-gas injection method, the injected gas occupies the pores with high oil saturation and causes the movement of oil in the un-swept parts of the reservoir. Subsequently, the residual and surrounded oil move around the reservoir rock by the injection of water, causing more reduction of the residual oil saturation [5-6]. Furthermore, water injection following gas injection prevents percent saturation and relative gas mobility from increasing, controls and reduces the mobility ratio and forms a sustainable front movement in the reservoir, thus preventing the formation of fast intermittent phenomenon in the production wells [7]. In comparison with the conventional gas injection methods, water-gas injection forms a three phase region and increases the contact surface of the fluid injected into the reservoir. This results in the improved efficiency of microscopic water injection and macroscopic gas injection, which increases the recovery coefficient and production yield of the reservoir [3, 5].

2. Field description

This field is located in the western margin of Karoon River, in an area with a very smooth topography and no considerable elevation at a height of 3-5 meters from the sea level. The dimensions of the field are 24 × 10 kilometers. The reservoir studied is known as Sarvak and contains relatively heavy crude oil with an API of 22 and thickness of 175-204 meters. According to the petrophysical and geological data and due to the difference in petrographic properties as well as the porosity variations and percent saturated hydrocarbon of this reservoir, it is divided into seven regions. Regions 6 have the highest porosity, NTG and best efficiency status. Specifications of the reservoir studied is shown in Table 1. The initial water oil contact (WOC) is 3265 mss.

3. Specifications of the reservoir model

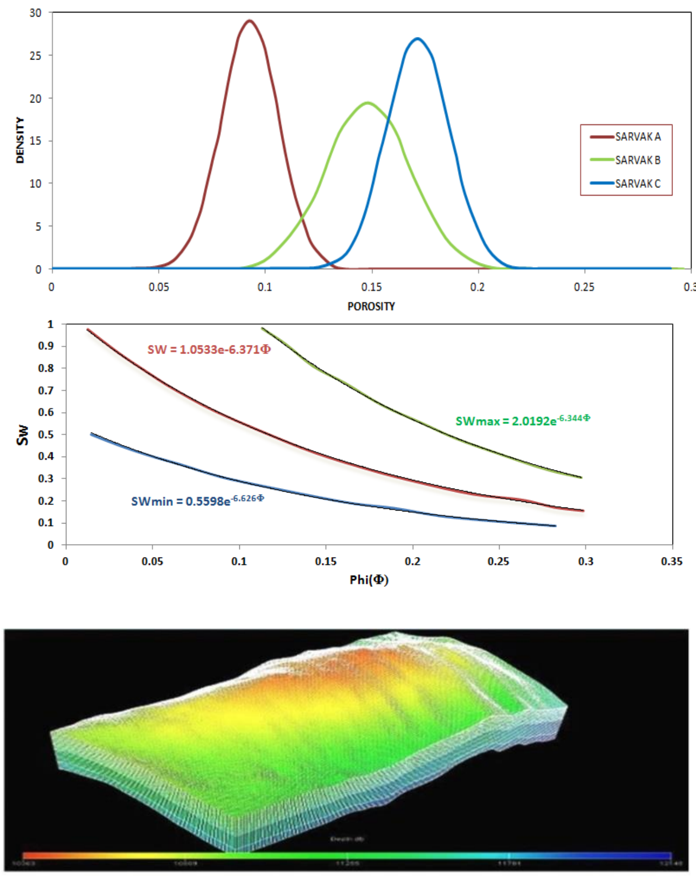

Figure 1. a) Porosity-Density Distribution Graph in the Sarvak Formation in the Field Studied, b) Saturation vs. Porosity Graph in Sravak Reservoir, c) Simulated Reservoir in the Field

To make the three-dimensional model of the reservoir, a grid network was first designed using Flow Grid software. In this network, the reservoir was divided into 83 grids in the longitudinal and 28 grids in the crosswise directions as well as 115 grids in the vertical direction based on the diversity of the rock type. The static information of the reservoir such as permeability, porosity and NTG has then been calculated for each grid by scaling up [8]. The networking in different layers of the reservoir is shown in Table 1.

Based on the reservoir model developed, the amount of the original oil in place has been calculated to be 979 million barrels. Sarvak layer has been divided into seven parts (Sarvak 1 in the top and Sarvak 7 in the bottom). Sarvak 5 zone, which appears to be equivalent to Ahmadi shale consists of thin layers of argillaceous and shale limestone and can be an appropriate rock coating for Sarvak reservoir. In addition, Figure 1 shows the saturation versus porosity graphs in Sarvak and the simulated reservoirs, respectively.

Water saturation has been calculated using the crossover saturation versus porosity graph and $Sw = a * e^{b\Phi}$ experimental equation, in which the graph coefficients in the maximum, fit and minimum states are as shown in Table 1 [9].

Table 1. Information for the Sarvak reservoir

<table>
<tr><th colspan="8">Specifications of the reservoir studied</th></tr>
<tr><td>Formation volume factor (FVF)</td><td>Viscosity</td><td>Reservoir temperature</td><td>Bubble pressure P_b</td><td>Initial pressure p_i</td><td>Gas to oil ratio GOR</td><td>Datum depth</td><td>API</td></tr>
<tr><td>Rbbl/STB</td><td>cP</td><td>F</td><td>psi</td><td>psi</td><td>Scf/stb</td><td>m.s.s</td><td></td></tr>
<tr><td>1.25</td><td>1.65</td><td>238</td><td>1090</td><td>5590</td><td>290</td><td>3160</td><td>22</td></tr>
<tr><th colspan="8">The networking in different layers of the reservoir model</th></tr>
<tr><td colspan="4">No. of X-Direction Cells</td><td colspan="4">83</td></tr>
<tr><td colspan="4">No. of Y-Direction Cells</td><td colspan="4">115</td></tr>
<tr><td colspan="4">No. of Z-Direction Cells</td><td colspan="4">28</td></tr>
<tr><td colspan="4">Permeability in X Direction(K_x)</td><td colspan="4">50 mDarcy</td></tr>
<tr><td colspan="4">Permeability in Y Direction(K_Y)</td><td colspan="4">50 mDarcy</td></tr>
<tr><td colspan="4">Permeability in Z Direction(K_Z)</td><td colspan="4">50 mdarcy</td></tr>
<tr><td colspan="4">X Grid Block Size(ft)</td><td colspan="4">234</td></tr>
<tr><td colspan="4">Y Grid Block Size(ft)</td><td colspan="4">248</td></tr>
<tr><th colspan="8">Specifications of the Sarvak reservoir in the field studied</th></tr>
<tr><td colspan="2">Reservoir</td><td colspan="2">Substrate</td><td colspan="3">Thickness (m)</td><td>Porosity (percent)</td></tr>
<tr><td colspan="2" rowspan="3">Sarvak</td><td colspan="2">A</td><td colspan="3">40</td><td>9</td></tr>
<tr><td colspan="2">B</td><td colspan="3">60</td><td>15</td></tr>
<tr><td colspan="2">C</td><td colspan="3">90</td><td>17</td></tr>
<tr><th colspan="8">Coefficients used in the Experimental Equation for calculation of Water Saturation, $Sw = a * e^{b\Phi}$</th></tr>
<tr><td colspan="2">Reservoir</td><td colspan="2">Curve</td><td colspan="3">a</td><td>b</td></tr>
<tr><td colspan="2" rowspan="3">Sarvak</td><td colspan="2">Low</td><td colspan="3">-6.626</td><td>0.5598</td></tr>
<tr><td colspan="2">Fit</td><td colspan="3">-6.371</td><td>1.0533</td></tr>
<tr><td colspan="2">High</td><td colspan="3">-6.344</td><td>2.0192</td></tr>
</table>

4. Sensitivity analysis

Based on the reservoir model developed for the field, the following sensitivity analysis have been performed for a more careful investigation of the reservoir performance: vertical to horizontal permeability ratios (K_v/K_h), aquifer volume with ratios of 1, 2 and 10 times the volume of Original oil in place, number of wells and wettability of the reservoir rock. The results of sensitivity analysis are shown in Table 2.

4.1. Sensitivity analysis of horizontal to vertical permeability ratios (Kv/Kh)

Sensitivity analysis of vertical to horizontal permeability ratios (K_v/K_h) (with ratios of 0.1, 0.5) and have been carried out in Sarvak formation and the results obtained will be discussed separately. The investigation of the sensitivity analysis of vertical to horizontal permeability ratios (K_v/K_h) indicates that increasing K_v/K_h ratio decreases the cumulative oil production and recovery coefficient (Figure 2(a)).

4.2. Sensitivity analysis of aquifer volume

Sensitivity analysis has been carried out based on the different aquifer volumes (4, 2 and 12) in Sarvak formation. Based on the results of the analysis, an aquifer to original oil in place ratio of 12 gives the best results (Figure 2(b)). Table 2 shows the results of the sensitivity analysis based on the aquifer to original hydrocarbon volume ratio.

4.3. Sensitivity analysis based on the number of wells

Sensitivity analysis based on the number of wells (15, 10 and 25) have been performed according to the following assumptions in Sarvak formation: 15 vertical wells, production flow rate of 40,000 barrels per day, permeability of 50 millidarcy, Natural depletion mechanism for production along with artificial lift method. The results obtained do not show any appreciable effect on enhancing recovery factor.

Table 2. Results of sensitivity analyses

Results of sensitivity analyses of vertical to horizontal permeability ratios					
Formation name	K_v/K_h	Permeability (mDarcy)	Plateau (Year)	Cumulative production (MMSTB)	Recovery coefficient (%)
Sarvak	0.1	50	7	145	16.1
	0.5		3	114	12.7
	1		1	78	8.7
Results of the sensitivity analysis based on the aquifer to in situ hydrocarbon volume ratio					
Formation name	Aquifer volume ratio (Aq/HPCV)	Permeability (mDarcy)	Plateau (Year)	Cumulative production (MMSTB)	Recovery coefficient (%)
Sarvak	2	50	2	44	4.9
	4		3	65	7.2
	12		5	145	16.1
Results of sensitivity analysis based on the number of wells					
Formation name	Wells number			Cumulative production (MMSTB)	Recovery coefficient (%)
Sarvak	10			144	14.8
	15			145	14.8
	20			146	14.9
Results of sensitivity analysis based on reservoir rock wettability					
Formation name	Wettability type	Permeability (mDarcy)	Plateau (Year)	Cumulative production (MMSTB)	Recovery coefficient (%)
Sarvak	Oil wet	50	3	104	11.6
	Neutral		4	139	15.4
	Water wet		5	145	16.1

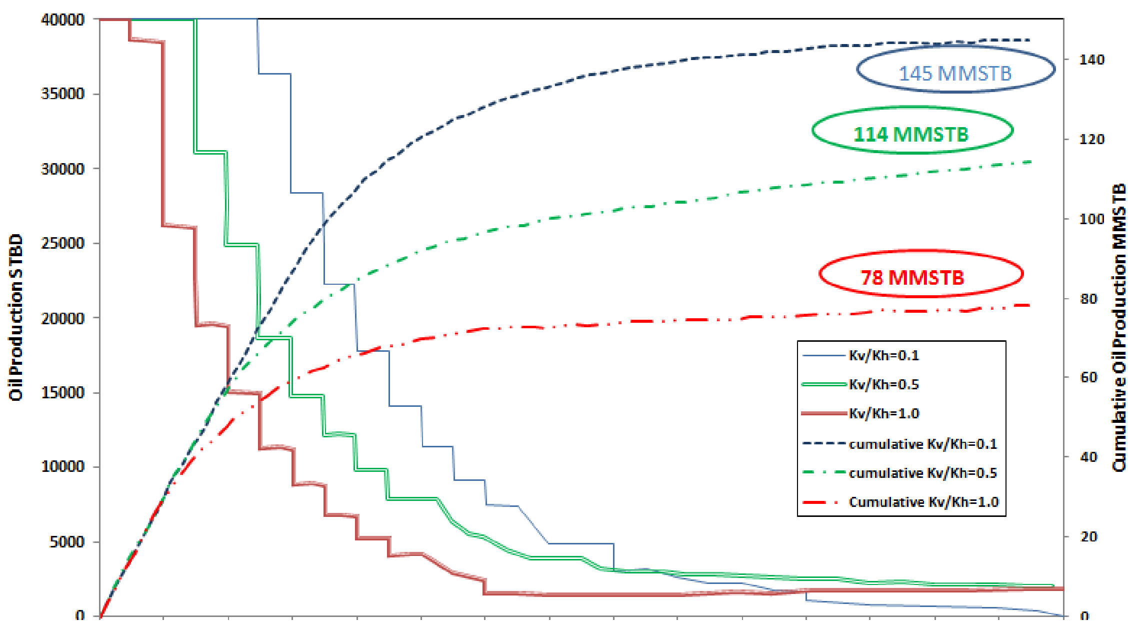

Figure 2. a) Effect of vertical to horizontal permeability ratio on the cumulative production from the field

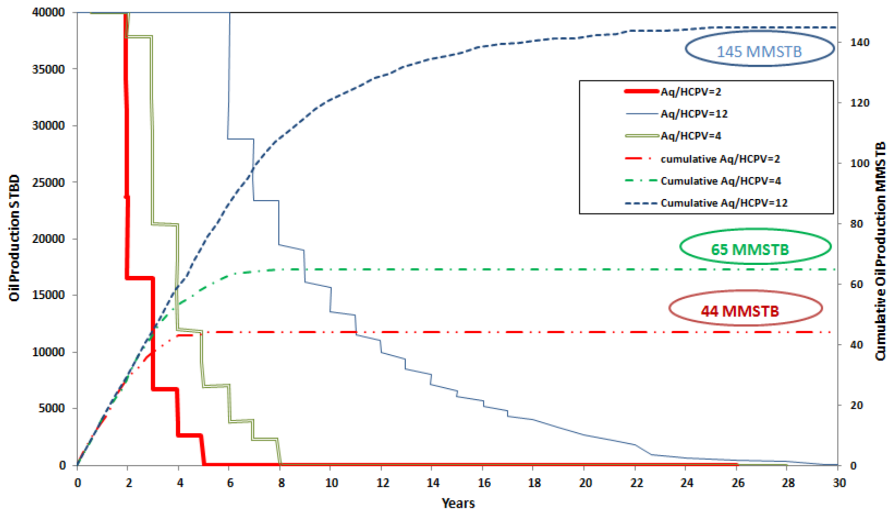

Figure 2b) Effect of aquifer volume on cumulative production in the field

4.4. Sensitivity analysis of reservoir rock wettability

The effect of the type of reservoir wettability has been analyzed based on the relative wettability data obtained from Sarvak reservoir. According to this analysis, the water-wet scenario has had a better effect on the enhanced recovery factor. Figure 3 shows the reservoir rock wettability diagrams for the water-wet, neutral and oil-wet cases.

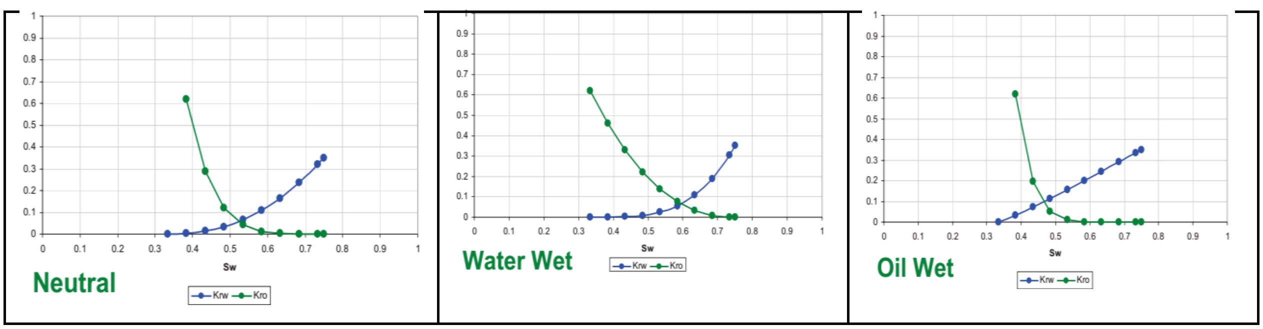

Figure 3. a) Reservoir rock wettability diagrams (hydrophilic, neutral and lipophilic)

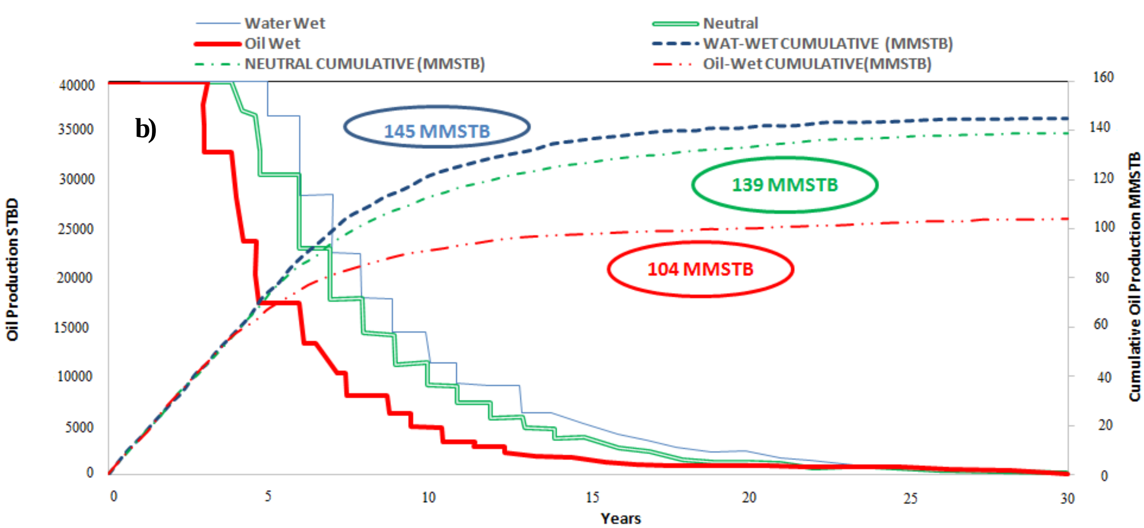

Figure 3b. Effect of reservoir rock wettability type on the field recovery efficiency

5. Reservoir simulation scenarios

5.1. Natural depletion

It was attempted to select the production wells as close to high reservoir rock permeability areas as possible. The locations of the production and injection wells are observed in Figure 4. In this scenario, 15 production wells have been selected as models and simulated. The minimum tubing head pressure (THP) considered for this modeling was 1200 psi. The economic constraints for the wells in the model included increasing the gas-oil ratio to 1200 (SCF/STB), water cut limit of 20% and reduction of reservoir production to 2000 STBD (Table 3). This scenario has been implemented for 19 years (2019-2037) and the production of 40,000 STBD with a plateau l of 6 years. Daily production rate per well of 2660 STBD and recovery factor of 15% have been calculated based on the scenario.

5.2. Gas injection

Production and injection wells are controlled by the amount of crude oil produced and injection rate, respectively. In this scenario, in addition to 15 production wells, 2 gas injection wells in the reservoir center with a maximum total rate of 60 million cubic feet per day have been predicted. To select the best layers for completion of the production wells, the selected layers have been tried to have more appropriate oil column and better permeability. In the simulation, the production wells have been completed in the 15-26 layers and injection into the oil layer been performed to move the oil. According to the model, the production of 50,000 STBD with a plateau of 8 years and recovery factor of 23.2% has been calculated. Considering the reservoir rock is water wet, gas injection has given a smaller recovery factor compared with water injection and water - gas injection.

5.3. Water injection

In this scenario, in addition to 15 production wells, 4 water injection wells with the injection rate of 60,000 STBD have been predicted and added to the model and the production wells have been completed in the same levels. Based on this scenario, the production of 60,000 STBD with a plateau of 6 years and recovery factor of 27.6% has been calculated.

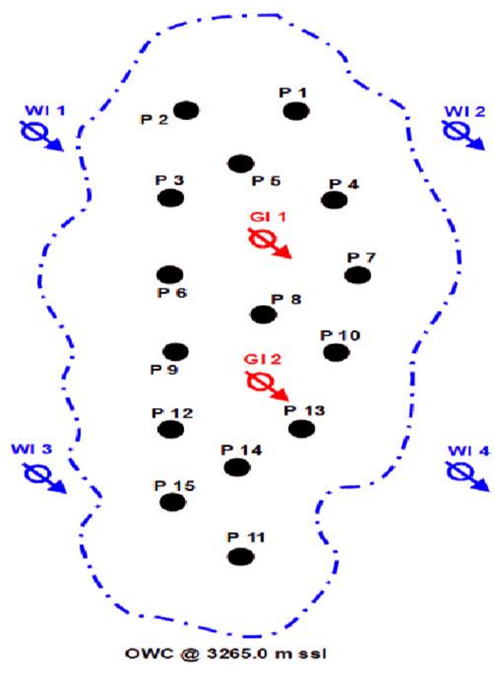

Figure 4a. Location of production and water and gas injection wells in the reservoir

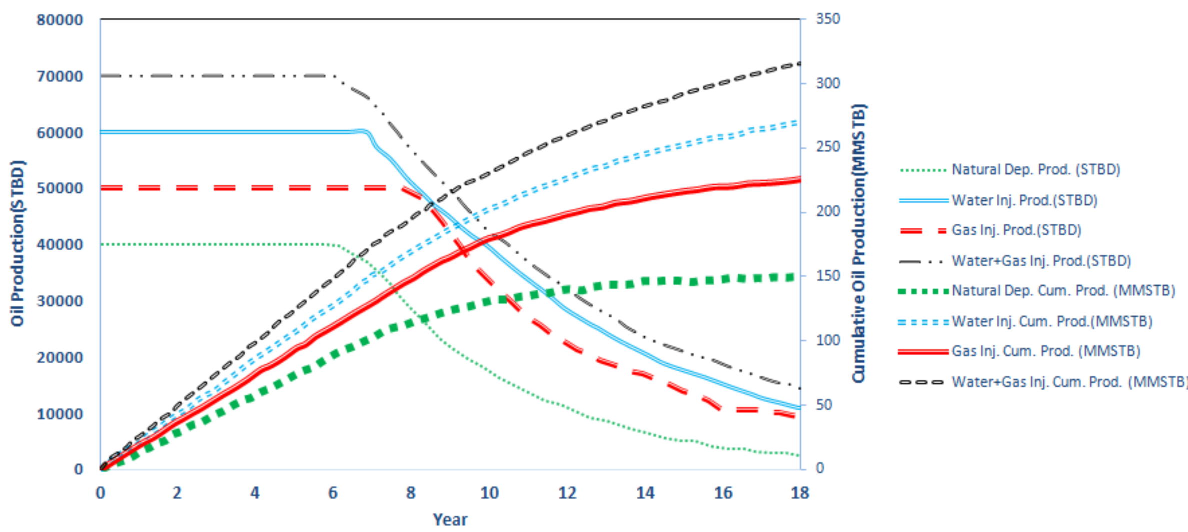

Figure 4b. Output of the results based on the simulation models in the scenarios

5.4. Water-gas injection

In this scenario, 6 injection wells including 4 wells with a total water injection of 60,000 barrels per day and 2 injection wells with a total gas injection of 60,000 cubic feet per day have been applied in the model. The results include the production of 70,000 STBD with a plateau of 6 years and recovery coefficient of 31.6%, which are the highest production and recovery factor (Table 3).

Table 3. Economic constraints of the production wells in the model and comparison of production scenarios from the reservoir

Produce oil (minimum (STBD)		Water cut (maximum) %		Gas to oil (maximum) SCF/STB		
2 000		20		1 200		
Scenario	Number of production wells	Number of gas injection wells	Number of water injection wells	Oil production rate (STBD)	Constant level production (Year)	Recovery coefficient (%)
Natural discharge	15	-	-	40	6	15.
Gas injection	15	2	-	50	6	23.2
Water injection	15	-	4	60	6	27.6
Water-gas injection	15	2	4	70	6	31.6

6. Conclusions

In this work, the performance of one of the reservoirs in south-west Iran has been investigated by four scenarios of natural depletion, water injection, gas injection and water-gas injection using ECLIPSE100 software along with sensitivity analysis to evaluate the reservoir performance. The most important findings are as follows: The recovery factors in natural depletion, water injection, gas injection and water gas injection scenarios are 15.5, 23.2, 27.6 and 31.6, respectively, indicating the highest recovery factor for water-gas injection. One of the most important problems of gas injection in this reservoir is gas movement towards the reservoir and water coning phenomenon due to the faster movement of gas compared with oil. According to the simulation results, the water-gas injection scenario gives the highest recovery factor. In addition, this scenario yields a smaller gas oil ratio (GOR) compared to the gas injection scenario and produces less water than the water injection scenario. According to the study carried out in this reservoir, water injection gives a higher recovery coefficient compared with gas injection considering the reservoir rock is water wet. The evaluation of the sensitivity analysis of vertical to horizontal permeability ratio (K_v/K_h) shows that increasing K_v/K_h ratio decreases cumulative oil production and thus reduces the recovery factor.

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