Comparison between Miscibility Effects of CO\textsubscript{2} and Solvent Gas Injection in Enhanced Oil Recovery Process

Reza Masoomi\textsuperscript{a,}\textsuperscript{*}, Iniko Bassey\textsuperscript{a}, Dolgow Sergei Viktorovich\textsuperscript{a}

\textsuperscript{a} Department of Petroleum Engineering, Kuban State University of Technology, Krasnodar, Russia

* Corresponding author. Tel.: +79649211147; E-mail address: r.masoomi451@yahoo.com

Abstract

In this study, miscible gas injection methods have been investigated in Khesht oil field of Iran and actual data of the field is used to modeling process. For this study first EOS of the reservoir fluid was made by using PVTi simulator. Then slim-tube simulator is used in order to obtain MMP for both CO\textsubscript{2} and Solvent gases. Then with respect to the obtained EOS which is provided by PVTi simulator, dynamic model of this field provided by using numerical simulator. After that the best scenario with respect to the highest oil recovery factor selected and the effects of both CO\textsubscript{2} and Solvent gases compared at the same time. At the end the results of miscible gas injection project have been considered.

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1. Introduction

Increasing demand of oil from one side and decreasing hydrocarbon reserves on the other hand make an inevitable need to use EOR methods to increase reserves. Enhanced oil recovery techniques are including thermal methods, miscible gas injection, immiscible gas injection, chemical flooding, polymer injection and microbial methods. Among this miscible gas injection is a common method in EOR. [1] The minimum miscibility pressure (MMP) is the most important parameters in the design of
miscible injection system that can be determined with laboratory methods, empirical relationships, computer simulations and analytical solving. In this study, miscible gas injection methods have been investigated in Khesht oil field of Iran. For doing this consideration to create models and simulation of different scenarios used PVTi and numerical simulator. [2] To modelling actual data of the field is used. At the end the results of miscible gas injection project have been considered.

2. Description of the considered field

Khesht oil field of Iran is a non-symmetrical anticline with the length of 11 km and width of 3 km. This oil field is single-porosity sandstone with 12 oil zone layers. This oil field has a high-grade light oil with API 37. Gas-oil ratio and FVF are 700SCF / STB and 1.4 Rbbl / STB. Khesht oil field is a new explored field and is in the development stage. Also is an under-saturated reservoir with oil-wet reservoir rock and without any gas-cap. This field includes 12 hydrocarbon layers with the total thickness of 196 meters. A summary of the characteristics of the field static model is presented in Table 1.

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of Grid Blocks in X-Direction</td>
<td>24</td>
<td>Length of Grid Blocks in X-Direction (radians)</td>
<td>400</td>
</tr>
<tr>
<td>Number of Grid Blocks in Y-Direction</td>
<td>25</td>
<td>Length of Grid Blocks in Y-Direction</td>
<td>450</td>
</tr>
<tr>
<td>Number of Grid Blocks in Z-Direction</td>
<td>12</td>
<td>Length of Grid Blocks in Z-Direction</td>
<td>50</td>
</tr>
<tr>
<td>Number of Oil Zone</td>
<td>12</td>
<td>Number of Cells</td>
<td>7200</td>
</tr>
</tbody>
</table>

2.1. PVT data of studied field

PVTi simulator was used to simulate the behaviour of the reservoir fluid at different temperatures and pressures. SRK three parameter method was used to regression of experimental and analysis software data and coefficients of EOS such changed to tune with experimental data. So that be able to predict reservoir fluid behaviour in different temperature and pressure conditions[3].

First we tried to get a perfect tune without any change in the composition of the sample, but because favourable results were not obtained, thus C7 plus were divided into two groups of C7+ and C14+. In continue to get better results also C14+ were divided into two groups of C14+ and C25+. This grouping is presented in Table 2. Splitting method with respect to Whitson solution method and Lee-Kessler EOS is used in is In this case. Obtained results from adjusting between EOS and real
experimental data are presented in Figures 1 to 3. Slim-Tube simulation was performed to find MMP for CO\(_2\) and Solvent gases injection in different pressure conditions.

Then the recovery curve was plotted versus the displacement pressure. So that recovery breaking point can be specified to determining value of MMP for CO\(_2\) and Solvent gases. As can observe in Figures 4 and 5 the MMP for Solvent and CO\(_2\) gases are 1902 psia and 2120 psia subsequently.

Table 2: Components of Reservoir Fluid

<table>
<thead>
<tr>
<th>Component</th>
<th>Mole Fraction</th>
<th>Component</th>
<th>Mole Fraction</th>
</tr>
</thead>
<tbody>
<tr>
<td>H(_2)S</td>
<td>0.5706</td>
<td>IC(_5)</td>
<td>1.218</td>
</tr>
<tr>
<td>CO(_2)</td>
<td>0.63909</td>
<td>NC(_5)</td>
<td>1.5962</td>
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<tr>
<td>C(_1)</td>
<td>6.2914</td>
<td>C(_6)</td>
<td>2.5673</td>
</tr>
<tr>
<td>C(_2)</td>
<td>2.0953</td>
<td>C(_7^+)</td>
<td>42.403</td>
</tr>
<tr>
<td>C(_3)</td>
<td>2.1477</td>
<td>C(_{14}^+)</td>
<td>28.514</td>
</tr>
<tr>
<td>IC(_4)</td>
<td>0.72337</td>
<td>C(_{25}^+)</td>
<td>9.3076</td>
</tr>
<tr>
<td>NC(_4)</td>
<td>1.9261</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Fig. 1: Adjusting the relative volume as a function of pressure
Fig. 2: Adjusting the dissolved gas in the oil as a function of pressure

Fig. 3: Adjusting gas FVF as a function of pressure

Fig. 4: Determination of MMP for CO₂
3. Scenarios presented

According to carried out surveys for scenarios four scenarios were introduced in this study. Six production and two injection wells are defined for all scenarios except natural depletion. The location of the wells is shown in Figure 6. In all scenarios first allowed the field to produce naturally to a value lower than the bubble point pressure and then injection is began.

3.1. The first scenario with variable pressures and constant flow rate

3.1.1. CO₂ Injection (CO₂=100%) at Pressures (2500, 3500, 4500, 5500, 6500 psia)

In this scenario first allowed the field to produce naturally to a value lower than the bubble point pressure and then CO₂ gas was injected into the field. [4] In this scenario, the gas injection flow rate was held constant, equals to 12500 Mscf. Then the gas injection pressures were changed respectively 2500 Psia, 3500 Psia, 4500 Psia, 5500 Psia to 6500 Psia. The results are presented in Figures 7 and 8.
3.1.2. Results of the Scenario

With respect to Figure 7 and 8 is observed that in CO₂ injection with constant flow rate of 12500 Mscf and variable pressures production GOR has increased when gas injection pressure is increased. Also reservoir pressure drop is lower and at the final cumulative oil production has increased. Since difference between production GOR in variables pressure and also difference between water cut in variables pressure was low value of Field oil production total (FOPT) and RF were basic for optimum pressure selection. So a pressure of 3500 Psia selected as optimum pressure with cumulative oil production of 77039680 STB and RF of 24.20 percent.
3.1.3 Solvent gas injection (SOLVENT=C1 35% + C2 65%) pressures (2500, 3500, 4500, 5500, 6500 Psia)

In this scenario first allowed the field to produce naturally to a value a little lower than the bubble point pressure and then Solvent gas was injected into the field. In this scenario, the gas injection flow rate was held constant, equals to 12500 Mcf. Then the gas injection pressures were changed respectively 2500 Psia, 3500 Psia, 4500 Psia, 5500 Psia to 6500 Psia. The results are presented in Figures 9 and 10.

![Figure 9: Field oil production total (FOPT) of the first scenario for Solvent gas at the injection pressures of (2500, 3500, 4500, 5500, 6500 Psia)](image)

![Figure 10: Field oil pressure rate (FPR) of the first scenario for Solvent gas at the injection pressures of (2500, 3500, 4500, 5500, 6500 Psia)](image)

3.1.4 Results of the Scenario

With respect to Figures 9 and 10 is observed that in Solvent injection with constant flow rate of 12500 Mcf and variable pressures when gas injection pressure is increased, reservoir pressure drop has decreased and at the final cumulative oil production has increased. Since difference between
production GOR in variables pressure and also difference between water cut in variables pressure was low value of FOPT and RF were basic for optimum pressure selection. So a pressure of 3500 Psia selected as optimum pressure with cumulative oil production of 86372680 STB and RF of 27.00 percent.

3.2. The second scenario with variable injection rates and constant pressure

3.2.1. CO₂ injection (5000,7500,10000,12500,15000 Mscf/D) at a constant injection pressure of 3500 Psia

In this scenario first allowed the field to produce naturally to a value a little lower than the bubble point pressure and then CO₂ gas was injected into the field. In this scenario, the gas injection pressure was held constant equals to 3500 Psia which has selected as an optimum pressure from scenario 1. Then the gas injection flow rates were changed respectively 5000 Mscf, 7500 Mscf, 10000 Mscf, 12500 Mscf, 15000 Mscf. The results are presented in figures 11 and 12.

Fig. 11: Field oil production total (FOPT) of the second scenario for CO₂ gas at the injection rates of (5000,7500,10000,12500,15000 Mscf)
3.2.2. Results of the Scenario

With respect to Figures 11 and 12 is observed that in CO₂ injection with constant pressure of 3500 Psia and variable injection rates reservoir pressure drop has decreased and at the final cumulative oil production has increased. Since difference between production GOR in variables pressure and also difference between water cut in variables pressure was low value of FOPT and RF were basic for optimum pressure selection. So injection rate of 15000 Mscf/D selected as optimum injection rate with cumulative oil production of 82956240 STB and RF of 25.92 percent

3.2.3 Solvent gas injection (5000,7500,10000,12500,15000 Mscf/D) at a constant injection pressure of 3500 Psia

In this scenario first allowed the field to produce naturally to a value a little lower than the bubble point pressure and then Solvent gas was injected into the field. In this scenario, the gas injection pressure was held constant equals to 3500 Psia which has selected as an optimum pressure from scenario 1. Then the gas injection flow rates were changed respectively 5000 Mscf, 7500 Mscf, 10000 Mscf, 12500 Mscf, 15000 Mscf. The results are presented in Figures 13 and 14.
3.2.4. Results of the Scenario

With respect to Figures 13 and 14 is observed that in Solvent gas injection with constant pressure of 3500 Psia and variable injection rates reservoir pressure drop has decreased and at the final cumulative oil production has increased. Since difference between production GOR in variables pressure and also difference between water cut in variables pressure was low value of FOPT and RF were basic for optimum pressure selection. So injection rate of 15000 Mscf/D selected as optimum injection rate with cumulative oil production of 92331848 STB and RF of 28.85 percent
3.3. The third scenario with variable oil flow rates and constant injection pressure and injection rate

3.3.1. The oil flow rates of (9000, 12000, 15000, 18000 STB/D) at a constant injection pressure of 3500 Psia and constant injection rate of 15000 Mscf for CO\(_2\) gas

In this scenario first allowed the field to produce naturally to a value a little lower than the bubble point pressure and then CO\(_2\) gas was injected into the field. In this scenario, the gas injection pressure was held constant equals to 3500 Psia which has selected as an optimum pressure from scenario 1 and also injection rate was held constant equals to 15000 Mscf which has selected as an optimum rate from scenario 2. Then the oil flow rates were changed respectively 9000 Mscf/D, 12000 Mscf/D, 15000 Mscf/D, 18000 Mscf/D. The results are presented in figures 15 and 16.

![Figure 15: Field oil production total (FOPT) of the third scenario for CO\(_2\) gas at the oil flow rates of (9000,12000,15000,18000 Mscf/D)](image1)

![Figure 16: Field oil pressure rate (FPR) of the third scenario for CO\(_2\) gas at the oil flow rates of (9000,12000,15000,18000 Mscf/D)](image2)
3.3.2. Results of the Scenario

With respect to Figures 14 and 16, it is observed that due to oil production with constant pressure of 3500 Psia and constant injection rate of 15000 Mscf and variable oil flow rates reservoir pressure drop has increased but at the final cumulative oil production has increased. Since difference between production GOR in variables pressure and also difference between water cut in variables pressure was low value of FOPT and RF were basic for optimum pressure selection. So oil flow rate of 18000 Mscf/D selected as optimum injection rate with cumulative oil production of 84233096 STB and RF of 26.32 percent.

3.3.3. The oil flow rates of (9000, 12000, 15000, 18000 STB/D) at a constant injection pressure of 3500 Psia and constant injection rate of 15000 Mscf for Solvent gas

In this scenario first allowed the field to produce naturally to a value a little lower than the bubble point pressure and then Solvent gas was injected into the field. In this scenario, the gas injection pressure was held constant equals to 3500 Psia which has selected as an optimum pressure from scenario 1 and also injection rate was held constant equals to 15000 Mscf which has selected as an optimum rate from scenario 2. Then the oil flow rates were changed respectively 9000 Mscf/D, 12000 Mscf/D, 15000 Mscf/D, 18000 Mscf/D. The results are presented in Figures 17 and 18.

![Graph](image)

Fig. 17: Field oil production total (FOPT) of the third scenario for Solvent gas at the oil flow rates of (9000, 12000, 15000, 18000 Mscf/D)
3.3.4. Results of the Scenario

With respect to Figures 17 and 18, it is observed that due to oil production with constant pressure of 3500 Psia and constant injection rate of 15000 Mscf and variable oil flow rates reservoir pressure drop has increased but at the final cumulative oil production has increased. Since difference between production GOR in variables pressure and also difference between water cut in variables pressure was low value of FOPT and RF were basic for optimum pressure selection. So oil flow rate of 18000 Mscf/D selected as optimum injection rate with cumulative oil production of 93646072 STB and RF of 29.26 percent.

3.4. The fourth scenario with the natural depletion of the studied field

No change is done on the field in this scenario and production is just by defined production wells.[5] There is no injection wells In this scenario and field daily production rate is 15000 STB/D. FGOR, FOPT, FPR and FWCT curves are presented in Figure 19. As can be seen the FOPT (cumulative oil production) is 52561972 STB/D in the natural depletion mechanism and also the RF is 16.43 percent.
5. Comparison between CO₂ and Solvent gas injection and natural depletion mechanism with respect to recovery factor

The purpose of this research is considering the performance of CO₂ and Solvent gas injection in different scenarios. Thus should be selected the scenario with the highest RF. To this purpose to have a reasonable comparison between injected gases the optimum value of each scenario has selected and then evaluated and compared with natural depletion mechanism individually.

In the first scenario that was based on constant injection rate and various injection pressures, optimum injection pressure for both CO₂ and Solvent selected equal to 3500 Psia in order to compare these gases with respect to obtained results. Also as shown in Figure 20 CO₂ and Solvent injections have higher RF than natural depletion mechanism with RF of 16.43 percent. Meanwhile obtained RF was 27 percent in Solvent injection that is higher than obtained RF of CO₂ injection which was equal to 24.2 percent.

As was mentioned the second scenario is based on constant gas injection pressure and various gas injection rate. Optimum injection rate of 15000 Mscf was selected for both CO₂ and Solvent gases to comparison of the two gases with respect to obtained results. Also as shown in Figure 21 CO₂ and Solvent injections have higher recovery than natural depletion mechanism with RF of 16.43 percent. Meanwhile RF of 28.85 percent was obtained in Solvent injection. This value of RF is more than RF by CO₂ injection which is 25.92 percent.
Fig. 21: Field oil production total (FOPT) at condition of optimum injection rate for CO2 and Solvent gases and natural depletion mechanism for the second scenario

In the third scenario that was based on constant injection rate and constant injection pressures with various production rate, optimum production rate of 18000 STB/D was selected for both CO2 and Solvent order to compare these gases with respect to obtained results. Also as shown in Figure 22 CO2 and Solvent injections have higher RF than natural depletion mechanism with RF of 16.43 percent. Meanwhile obtained RF was 27 percent in Solvent injection that is higher than obtained RF of CO2 injection which was equal to 26.32 percent.

Finally, all scenarios in optimum conditions and natural depletion mechanism are presented in the form of a bar chart 23 that indicate the percentage of RF.

Fig. 22: Field oil production total (FOPT) at condition of optimum production rate for CO2 and Solvent gases and natural depletion mechanism for the third scenario
Figure 23 summarizes the result of various miscible injection scenarios on the studied field. This figure represents a bar graph of comparing between the cumulative oil recovery factor of the studied field in various scenarios and also natural depletion of the field. According to this figure recovery factor of studied field is predicted 16.43% in the case of natural depletion. While recovery factor in the scenario of optimum injection pressure (3500 psi) is predicted 24.2 % for CO2 and 27% for Solvent. Third from left bar graph shows that recovery factor will be 25.92% for CO2 injection in the optimum value of 15000 Mscf. While the sixth bar shows 28.85% recovery factor for Solvent injection in the same optimum injection rate. Also the last bar graph represents the third scenario, the optimal production rate (18000STB/D), that the recovery factor is predicted 29.26% for Solvent injection and 26.32% for CO2 case.

6. Conclusions

The following conclusions can be drawn from this research:

i. The MMP for Solvent and CO2 are 1902 Psia and 2120 Psia respectively in this case study.

ii. The cumulative oil production rate (FOPT) in the natural depletion mechanism is 52561972 STB. Also recovery factor of the natural depletion mechanism is 16.43 percent.

iii. Gas injection rate is most influential factor among the defined scenarios in the production. And also the third scenario with the highest cumulative oil production is selected the best scenario between these scenarios.

iv. According to the above results, firstly cumulative oil production in miscible gas injection is more than natural depletion mechanism secondly cumulative oil production in Solvent gas injection is more
than CO\textsubscript{2} injection. Because MMP for Solvent is less than MMP for CO\textsubscript{2} and Solvent gas has been miscible with oil phase at a pressure lower than the CO\textsubscript{2}.

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References


