Immiscible Recycle Gas Injection Scenario: Simulating Optimum Conditions in One of the Iranian Oil Reservoirs

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Abstract

Immiscible gas injection is one of the most common EOR methods used for various reservoir conditions. In this work, immiscible recycle gas injection, as an enhanced oil recovery scenario for improving recovery efficiency in one of the south-west Iranian oil reservoirs, is simulated by commercial simulator, Eclipse. The reservoir fluid is light oil with gravity of 43 ^{o}API. The oil bearing formations are carbonate and so dual porosity/dual permeability behavior was chosen for better representation of the fracture system. Different sensitivity analysis with respect to several parameters like number and location of injection/production wells, production/injection rate, completion interval and etc is performed. It has been observed that in sensitivity with number of wells, 1 injection/3 production wells was the most efficient case. Also well oil production rate of 200 SM^3/Day and well bottom-hole pressure of 75 bar provided higher oil recovery. Completing injection wells in fracture and production wells in matrix has a better field oil efficiency in comparison to other cases. Finally we proposed optimum conditions for immiscible recycle gas injection in this reservoir which maximizes oil recovery efficiency.

Keywords: Immiscible Gas Injection, Simulation, Oil Reservoirs, Sensitivity.

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1. Introduction

In conventional oil recovery projects, the decline of primary production to an uneconomic level led to the development of various methods to increase the oil recovery efficiency before abandonment of a reservoir. The term enhanced oil recovery (EOR) basically refers to the recovery of oil by any method beyond the primary stage of oil production. It is defined as the production of crude oil from reservoirs through processes taken to increase the primary reservoir drive. These processes may include pressure maintenance, injection of displacing fluids, or other methods such as thermal techniques. Therefore, by definition, EOR techniques include all methods that are used to increase cumulative oil produced (oil recovery) as much as possible [1]. Enhanced oil recovery can be divided into two major types of techniques: thermal and non-thermal recovery. Non-thermal recovery methods can be split into: water flooding, gas injection (including: LPG miscible slug, enriched gas miscible process, high pressure lean gas miscible process, carbon dioxide process) and chemical processes (including: micellar polymer flooding, caustic flooding, polymer flooding). Thermal recovery refers to oil recovery processes in which heat plays the principle role. The most widely used thermal techniques are in situ combustion, continuous injection of hot fluids such as steam, water or gases, and cyclic operations such as steam soaking [1].

In gas injection processes there are two major types of gas injection, miscible gas injection and immiscible gas injection. In miscible gas injection, the gas is injected at or above minimum miscibility pressure (MMP) which causes the gas to be miscible in the oil. On the other hand in immiscible gas injection, flooding by the gas is conducted below MMP. This low pressure injection of gas is used to maintain reservoir pressure to prevent production cut-off and thereby increase the rate of production [1]. The combination of light crude, relatively high reservoir temperature, and relatively low reservoir pressure favored immiscible gas injection as the most suitable EOR process [2].

The previous studies have shown that immiscible crestal gas injection had potential for increasing oil recovery by the following mechanisms:

- An alternate reservoir energy source can be created in the secondary gas cap to diminish the effects of the aquifer. Pressure increase on the crest can slow or neutralize the advance of water.
- Gas displaces oil more efficiently than water. The end-point recovery by gas is 50 percent compared to 30 percent by water.
- Vertical displacement of oil bye gas, with gravity segregation forces, will add to the incremental recovery.
- Oil swelling and viscosity reduction will contribute to improved oil recovery [3].

Injection of a fluid such as water or gas, under appropriate conditions, has become the usual practice to recover additional oil after primary production. These methods, commonly known as secondary recovery methods, usually recover 5-20 % of remaining oil after primary production. However these fluids, being immiscible with the reservoir oil, leave high residual oil saturation, (40% - 60% OOIP) after displacement. Gas recycling is one of the methods which is used as an EOR scenario for producing unrecovered oil reserves. In this method some injection wells are drilled and a fraction of producing field gas is re-injected into injection wells.

In this study we used commercial simulator, Eclipse, to simulate immiscible recycle gas injection in a specific sector, which is a quarter of one of the Iranian south-west oil reservoirs. Reservoir rock and fluid data were evaluated and merged into Eclipse/PVTi simulator. History matching study was done with production data to verify the results of the simulator with field data. Different sensitivities with respect to location and number of wells and also injection/production parameters were performed in this reservoir. Finally optimum conditions under this EOR method were suggested.

2. Reservoir Properties

The reservoir fluid is light oil with gravity of 43 ^{o}API. Initial state of reservoir and properties of the reservoir fluid as well as constrains which should be applied are presented in the following tables.

Table 1: Initial conditions.

Initial Reservoir Pressure (bar)	168
Reservoir Temperature (^{o}F)	120
Initial Water-Oil contact (ft S.S)	3200
Initial Gas-Oil contact (ft S.S)	1850

Table 2: Physical properties of reservoir oil.

Bubble Point Pressure(bar)	API	Viscosity (cp)
135.2	43	0.56

Table 3: Constrains in simulation.

Minimum BHP (bar)	25.4
Maximum GOR (scf/STB)	800
Maximum WCT (%)	50
Production Life (year)	15

3. Model Description

In this study we are going to model this reservoir with Eclipse-100. Cartesian coordinates with corner point geometry were selected for the model. Dual porosity and dual permeability behavior was chosen for better representation of the fracture system. Fully implicit pressure solution method was agreed to be used. Grid model and properties are shown in Figure 1 and the Table 4.

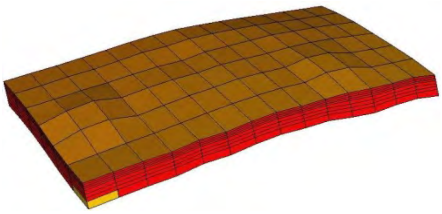

Figure 1: Grid model of the field.

Table 4: Properties of the grids in simulation.

No of Cells in X Direction (N_X)	6	Grid Size in Z Directio (D_Z, m)	5
No of Cells in Y Direction (N_Y)	14	K_X (md)	51
No of Cells in Z Direction (N_Z)	8	K_Y (md)	51
Grid Size in X Directio (D_X, m)	177	K_Z (md)	42
Grid Size in Y Directio (D_Y,m)	177	$\varnothing$ (percent)	12.35

3.1. Production Data

Oil in place was calculated by IRAP software to about 1400 million barrels with abandonment pressure to be 105.5 bar. This figure was confirmed by simulation software giving a value of 1379 million barrels. Cumulative production by 2001 was about 155 million barrels.

3.2. PVT Data

Precise and accurate characterization of a reservoir fluid is a very important factor in reservoir simulation studies. In gas flooding processes because of existance of a great interaction between injected and in place fluids, it is very important to characterize the reservoir fluid very accurately. PVT experiments are usually expensive and performed in limited conditions. Therefore EOS based PVT packages are used widely for the prediction and evaluation of fluid properties, in well and surface conditions over a wide range of temperature, pressure and composition.

In this work using PVTi module of ECLIPSE simulation software, three parameter Peng-Robinson EOS, which predicts the behavior of the Iranian reservoirs' fluid quite well, was tuned to present fluid sample of the reservoir. Lohrens-Bray-Clark (LBC) was used as viscosity correlation. For whole of the reservoir just one composition was considered. Amongst different available PVT samples, the one which describes behavior of the reservoir fluid better and accords the most with real data was taken as reservoir fluid representative.

Components defined in PVTi and EOS was tuned without any grouping since in a non-compositional run no grouping is needed. The results of the tuning process for the liquid density, liquid viscosity and oil relative volume that will be used in this study are given in Figure 2 to 4, respectively.

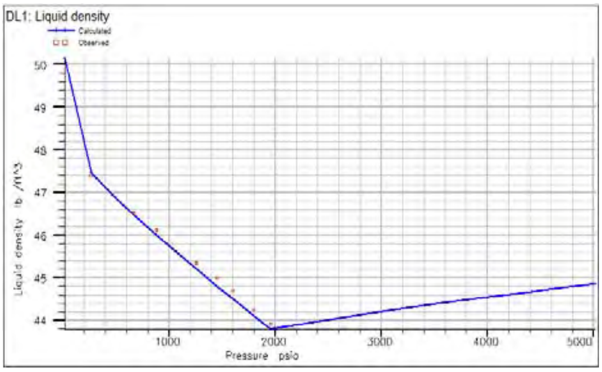

Figure 2: Comparison of calculated and observed liquid densities.

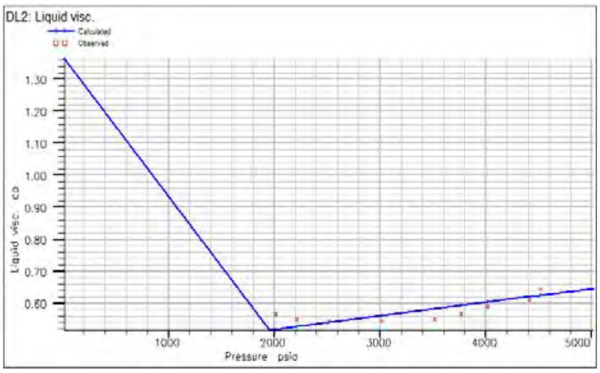

Figure 3: Comparison of calculated and observed liquid viscosities.

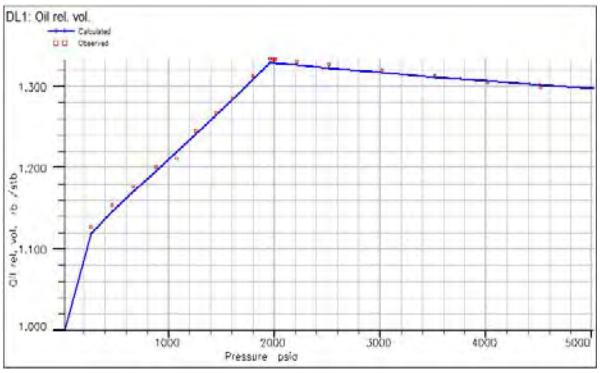

Figure 4: Comparison of calculated and observed oil relative volumes.

After inserting the petrophysic, PVT and initialization data in the model, and also rock-type determination of grids in the model (that depends on the grid porosity and initial water saturation), the model is ready for various studies. In this study, the locations for the production wells, A, B, C and D are known at the beginning of the production. All well configurations are vertical.

4. Results and Discussion

4.1. Natural Depletion

The sector would produce from year 1935 up to 2005 when producing wells shut down. Following information are available from field production data during natural depletion:

- The sector ultimate oil recovery in natural depletion will be 39.85% after 70 years of oil production.
- Initial reservoir pressure is around 168 bar and finally after 70 years of oil production, it reduces to 36.6 bar. At the early production times, field pressure rate decreases sharply, so this sector is a good candidate for EOR processes after 30 years of oil production. We implement Immiscible Gas Recycling scenario from year 1976.
- During this production scenario, the field initial production rate is around 5000 bbl/day. Around year 1977 two production wells shut down, and from year 1992 two other production wells started to produce from this sector. At year 2005 these two wells also shut down. There is a sharp decline of oil production rate from year 1996; thus this sector is a candidate for EOR processes.
- During natural depletion period, the average GOR of this sector is about 2500 SCF/STB.
- This sector produces negligible water during natural depletion interval.
  A comparison of natural depletion and simulated case is provided at the end part.

4.2. Immiscible Recycle Gas Injection Scenario

During this production scenario, the final average field pressure reaches about 36.6 bar after 70 years from start of production and there is a sharp decline of oil production rate from year 1996. Also there is a sharp decline of oil production rate after year 1992 from two last production wells (C, D). Therefore, it cannot be considered to be local well and/or formation damage. So this sector is a candidate for EOR processes. In this study the method of immiscible recycle gas injection has been simulated. This production strategy has resulted in better efficiency and therefore higher oil recovery and good economics. The simulation results illustrate the influence of immiscible recycle gas injection. In this scenario, the field produces naturally until 2005, we implement EOR scenario from year 1976, because of reservoir pressure decline. Some issues are considered as follow.

4.2.1. Sensitivity with Number of Wells

In this part we use different number of wells with different configurations, which in each configuration the best is selected for comparison with others. We have investigated the effect of number of wells on the efficiency of both natural depletion and gas recycling mechanisms. With increasing the number of wells, the recovery factor increases. If the recovery factor is stable with increasing the number of wells, the optimum number of wells is obtained. Some of the best different cases that are selected for investigating the influence of the number of wells on the recovery are given in table 5 and Figures 5 and 6. From the results, 1-injection/3-production pattern has the highest efficiency and after that 1-injection/2-production pattern is the most efficient case, but in the first case the fluctuation in GOR of producing wells is high. Thus we choose the case 1-injection/2-production as optimum one in this part.

Table 5: Number of wells and FOE.

Number of Wells	Maximum FOE	Average Field Pressure (bar)
1 PRO	0.46	29.00
Recycling-1INJ/1PRO	0.50	89.70
Recycling-1INJ/2PRO	0.66	83.50
Recycling-1INJ/3PRO	0.68	83.50
Recycling-2INJ/1PRO	0.50	90.30

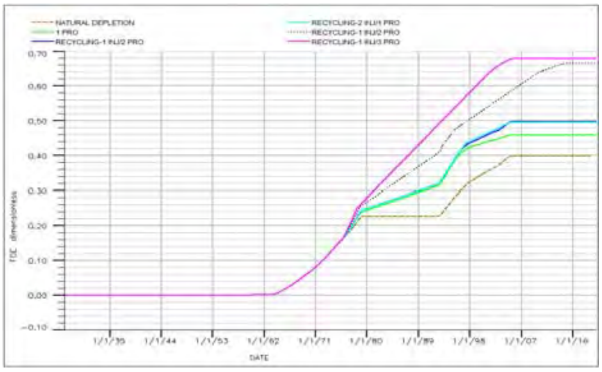

Figure 5: Field oil efficiency for different number of wells.

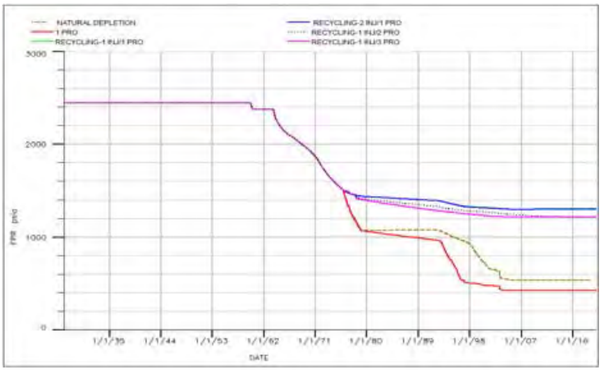

Figure 6: Field pressure for different number of wells.

4.2.2. Effect of Well Pattern on Oil Recovery Efficiency

Optimum performance can be achieved with the patterns defined in the following table by controlling the rates of injectors and producers. These calculations can be performed analytically if we assume the displacing and displaced fluids are incompressible, the mobility ratio is one, and the reservoir has uniform properties. Note that the location of the injection wells was optimized by different factors such as permeability, transmissibility, porosity, and oil saturation distributions. By considering mentioned factors we try different patterns in this sector for optimizing well locations for the previous section (1-Injection/2-Production). Different configurations are presented in table 7.

Field oil efficiency of different configurations is shown in table 8. By comparison different configurations, we select the configuration-2 which has a higher efficiency than other configurations.

Table 6: Producer-to-Injector ratios for common well patterns.

Well Pattern	Producer : Injector Ratio
Four-Spot	2
Five-Spot	1
Direct Line-drive	1
Staggered Line-drive	1
Seven-Spot	1/2
Nine-Spot	1/3

Table 7: Well locations.

Configuration-No	Inj-01		Prod-01		Prod-02	
	i	J	i	j	i	j
1	20	46	20	48	20	56
2	20	53	20	46	20	59
3	20	53	20	46	20	51
4	17	54	20	48	20	56
5	15	52	20	47	18	54
6	20	52	15	47	15	57
7	20	46	19	50	20	52

Table 8: Field oil efficiency for different well locations.

Configuration-No	Field Oil Efficiency
1	0.666
2	0.680
3	0.652
4	0.666
5	0.540
6	0.432
7	0.576

4.2.3. Sensitivity Analysis on Injection and Production Parameters

4.2.3.1. Sensitivity Analysis on Production Parameters

❖ **Sensitivity on Production Rate**

In this part we test different rates of production for both wells (PRO-01/PRO-02). The results are shown in the table 9 and figure 7. From the table we can see that two cases; WOPR=350 SM^3/Day and WOPR=200 SM^3/Day have higher efficiency in comparison to others cases. But with WOPR=350 SM^3/Day the instability in GOR of both wells is very high with respect to case which WOPR=200 SM^3/Day , and in the second case well produce up to year 2019, which in the first case (WOPR=350 SM^3/Day) well shut down in year 2005; so in this part we propose the case which WOPR is 200 SM^3/Day.

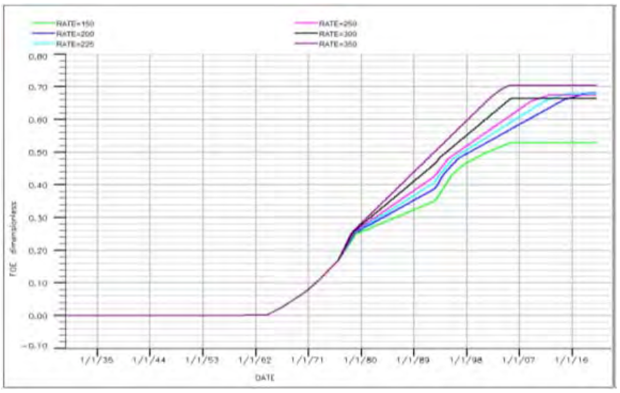

Figure 7: Field oil efficiency for sensitivity analysis on rate.

Table 9: Sensitivity on production rate.

Rate (SM^3/Day)	Field Oil Efficiency
150	0.528
200	0.682
225	0.680
250	0.676
300	0.664
350	0.704

❖ **Sensitivity on Production Wells Bottom Hole Pressure**

We selected 6 different cases to investigate the effect of bottom-hole pressure on recovery efficiency (presented in the table 10). Generally the higher bottom-hole pressure as a constrain for controlling the production, leads to more oil residue in a reservoir; thereupon it reduces the recovery factor. By optimizing this parameter; value of 75 bar was selected as an optimum well bottom-hole pressure. At this WBHP, FOE has the maximum value, as it is shown in the following table.

Table 10: Sensitivity on production well bottom hole-pressure.

Case	WBHP (bar)	FOE
1	15	0.6826
2	25	0.6821
3	50	0.6848
4	75	0.6864
5	100	0.4980
6	150	0.4860

4.2.3.2. Sensitivity Analysis on Injection Parameters

❖ **Sensitivity Analysis on Injection Rate**

One of the important concerns in gas injection processes is the stability of displacement, because under unfavorable conditions, unstable displacement will lead to poor macroscopic (volumetric) sweep efficiency. Two natural phenomena which cause unstable displacement and jeopardize volumetric sweep efficiency are gravity override and viscous fingering. At this part the effect of gas injection rate on the recovery is investigated. We change this parameter by different injection fraction which is defined in item 6 of "GCONINJE" keyword for injection well. These fractions and the respective FOE are listed in the table 11.

Table 11: Sensitivity on injection rate.

Case	Re-injection Fraction	FOE
1	0.25	0.484
2	0.50	0.508
3	0.75	0.528
4	1.00	0.686

The simulation result from this study indicates that the injection scheme of case 4 of produced gas can be the best development scheme, but we should consider that this case in which produced gas is totally re-injected into the reservoir is idealistic. We continue the rest of sensitivity analysis by this value (case-4).

- ❖ **Sensitivity Analysis on Injection Pressure**

In this part of study, effect of injection pressure on the oil recovery from the sector model has been investigated. Simulation runs have been conducted with injection pressures of 100, 175 and 250 bar, Figure 8 shows field oil efficiency curves of different cases. As it can be seen in Figures 8 and 9 for injection pressures of 100, 175 and 250 bar final oil recoveries are 47.25%, 68.72% and 68.80% respectively, between two cases of 100 bar and 250 bar there is a significant increase in final oil recovery but by increasing injection pressure from 175 to 250 bar there is a small increase in FOE. It can be understood that for injection pressures higher than 175 bar displacement front pressure reaches minimum miscibility pressure. It is clearly seen in Figure 2 that incremental oil recovery due to miscible injection is significant; however the marginal increase in oil recovery as the result of injection at pressures higher than 175 bar may not compensate for additional equipment and operating costs at higher pressures. Thus in this section bottom hole pressure of 175 bar will be proposed.

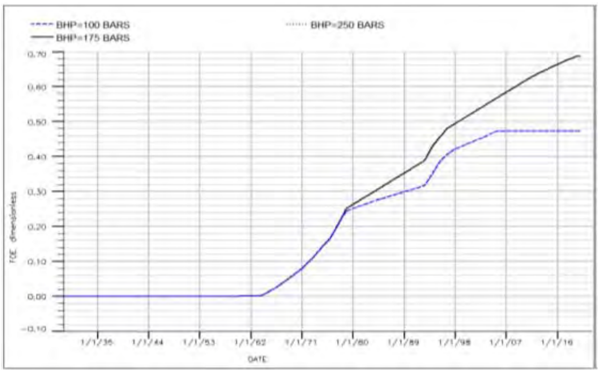

Figure 8: Field oil efficiency for sensitivity analysis on injection well BHP.

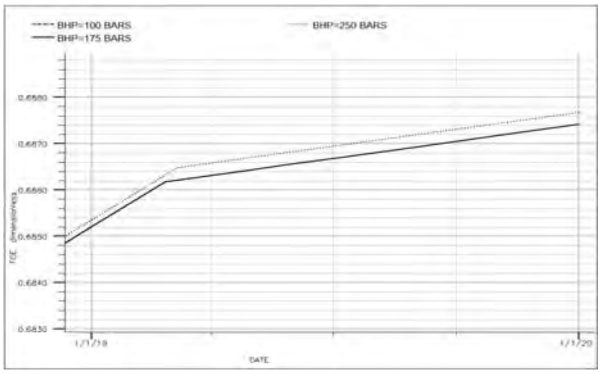

Figure 9: Field oil efficiency for sensitivity analysis on injection well BHP- close up view.

4.2.4. Sensitivity Analysis on Completion Interval

Oil recovery efficiency depends strongly on the completion interval of injection and production wells. Since this oil field is a fractured reservoir, we simulate this sector by dual-porosity, dual-permeability option of Eclipse simulator. To complete the wells, we can complete injection and production wells in matrix and fracture parts of the reservoir. We try this at different conditions. At first we complete injection wells in fracture and production wells in matrix, and then try completion of production wells in fracture and injection wells in matrix. For the third case we complete both injection and production wells in the matrix and finally completes them in fracture. Results of this part of simulation have been shown in the following figure.

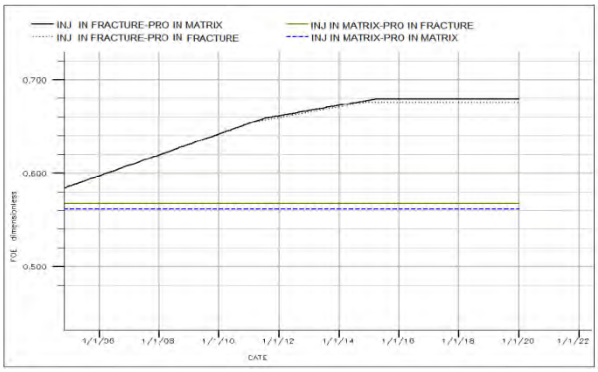

Figure 10: Field oil efficiency for sensitivity analysis on completion interval - close up view.

As shown in the Figure 10, completing injection well in fracture and production wells in matrix has a better field oil efficiency. The reason for this is that completing of injection wells in matrix causes injected gas or fluid move swiftly toward fracture and result in bad sweep efficiency, but if we complete injection wells in fracture the injected fluid or gas sweep the unrecovered oil in a better state, and it results higher areal or volumetric sweep efficiency. Thus for this part we propose completion of injection well in fracture and production well in matrix.

4.3. Optimum Immiscible Recycle Gas Injection Conditions

At the final step of this study during different sections through this work we propose optimum conditions for immiscible recycle gas injection to this sector. Optimum well numbers are one injection well (Inj-01) and two production wells. Locations of these wells are listed in the table 12. Configuration of this well pattern is depicted in the Figure 11, which is the output of FLOVIZ section of Eclipse. Parameters of production and injection are listed in the table 13. Final results of simulation are presented in the Figures 11-16 in comparison with natural depletion.

Table 12: Location of injection and production wells.

Configuration / Well Name	i	j	k_1	k_2
Inj-01	20	53	9	13
Pro-01	20	46	2	5
Pro-02	20	59	2	5

Table 13: Parameters of production and injection.

Maximum BHP of Injection Well (bar)	175
Minimum BHP of Production Wells (bar)	75
Production Rate of Production Wells	200
Injection Well Control Mode	GRUP (item 4 in keyword WCONINJE)

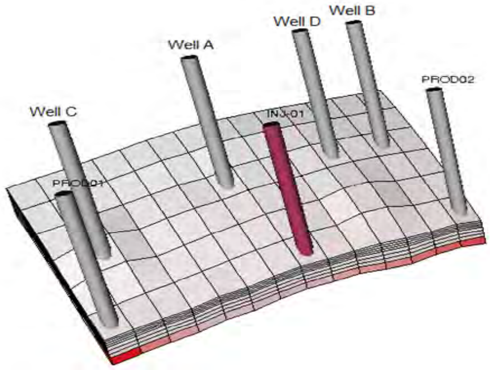

Figure 11: Shape of the sector model at optimum well number and location.

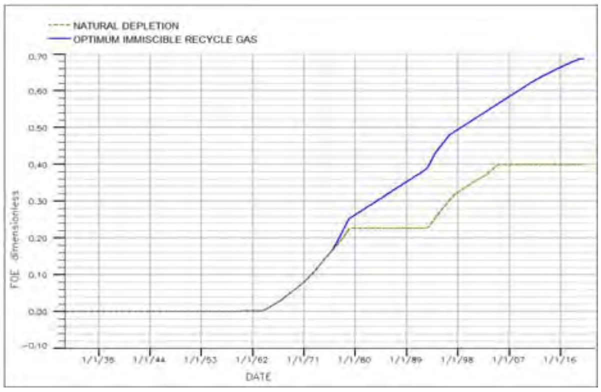

Figure 12: Field oil efficiency of optimum EOR condition in comparison with natural depletion.

Figure 13: Average field pressure of optimum EOR condition in comparison with natural depletion.

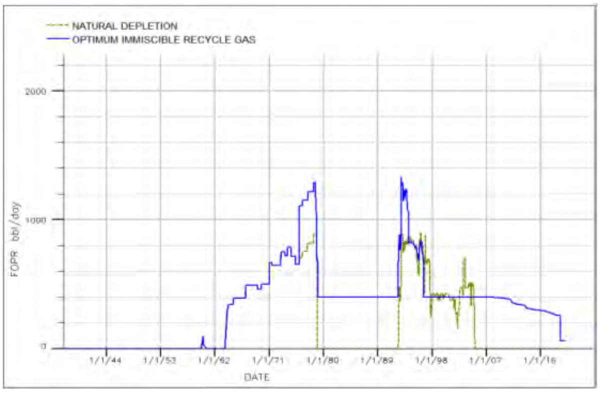

Figure 14: Field oil production of optimum EOR condition in comparison with natural depletion.

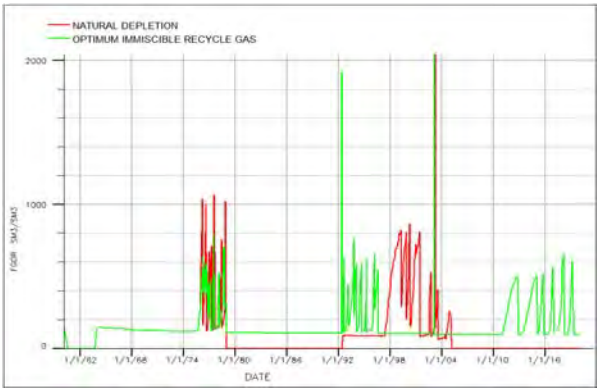

Figure 15: Field gas oil ratio of optimum EOR condition in comparison with natural depletion.

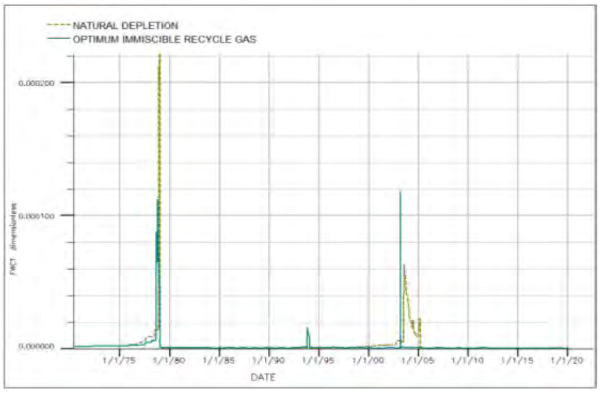

Figure 16: Water cut of optimum EOR condition in comparison with natural depletion

5. Concluding Remarks

- Immiscible recycle gas injection is one of the common EOR methods used for various reservoir conditions.
- Location of the injection wells was optimized by different factors such as permeability, transmissibility, porosity, and oil saturation distributions.

- After sensitivity analysis the two production wells and one injection well has been proposed as the optimum number of wells.
- For completion interval, generally we propose completion of injection well in fracture and production wells in matrix.
- The gas injection rate was found to have considerable effects on the reservoir recovery. By reducing the gas injection rate, the recovery factor also decreases.
- It is shown that the recovery factor form 39.85% during the natural depletion has increased to 68.72% during the gas recycling. Note that this recovery is under condition of complete reinjection of produced gas; with reinjection of smaller fraction of produced gas, recovery factor would be smaller.
- Reservoir communication and lateral connectivity are important elements to demonstrate the feasibility of any gas flooding development plans; interference test must be performed between wells of reservoir to demonstrate pressure and fluid communication between available wells.
- The present study was an immiscible process. So for finding the miscibility conditions, several slim tube displacement experiments should be performed.
- In a compositional simulation the effect of wellhead pressure on the recovery must be found. Though it is expected that decreasing the well-head pressure results higher gas and condensate recovery.

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