Petroleum Science and Technology
Publication details, including instructions for authors and subscription information:
http://www.tandfonline.com/loi/lpet20

Recovery Improvement Using Water and Gas Injection Scenarios

M. F. Tafty [a] , M. Masihi [a] & A. Momeni [b]

[a] Department of Chemical and Petroleum Engineering , Sharif University of Technology , Tehran , Iran

[b] Cape Company , Tehran , Iran

Published online: 07 Feb 2012.

Petroleum Science and Technology, 29:290–300, 2011

ISSN: 1091-6466 print/1532-2459 online
DOI: 10.1080/10916460903330270

Recovery Improvement Using Water and Gas Injection Scenarios

M. F. TAFTY,[1] M. MASIHI,[1] AND A. MOMENI[2]

[1]Department of Chemical and Petroleum Engineering, Sharif University of Technology, Tehran, Iran
[2]Cape Company, Tehran, Iran

Abstract *Water and miscible gas injection scenarios are considered in an Iranian oil reservoir for the purpose of recovery improvement. Firstly reservoir fluid modeling and modeling of a slim tube test were performed. Then, water alternating gas (WAG) injection was evaluated by optimizing the WAG half cycle and WAG ratio. Alternatively, hybrid WAG and separate injection of water and gas in the top and bottom of the reservoir were also investigated. The numerical simulation results showed that the optimum WAG, with half cycle of 1.5 years and WAG ratio of one, gave the highest recovery factor. Moreover, economic evaluation of these scenarios indicated that WAG had the highest net present value and was the most interesting scenario for improving the recoveries.*

Keywords hybrid WAG, minimum miscibility pressure, water alternating gas

1. Introduction

The typical oil production of primary recovery of Iranian oil reservoirs is relatively low, about 20% of the original oil in place. On the other hand, most oil reservoirs in the country have passed the primary recovery and there is a need for mechanisms beyond natural production. This is why the state company has focused on enhanced oil recovery (EOR) methods in the past few years.

There are various EOR techniques from gas injection to thermal and chemical injections applicable to various reservoirs depending on the fluid and rock properties and reservoir depth. However, the description of these methods is beyond the scope of this article. It should be emphasized that each method has its own limitations. For example, continuous gas injection (CGI) in the conventional horizontal flooding patterns leads to severe gravity segregation and poor reservoir contact (sweep) volumes. To improve the sweep efficiency, a water alternating gas (WAG) process has been widely practiced in the industry. The potential of improved reservoir sweep and reduced gas requirements are reasons for WAG's wide application (Kulkarni and Rao, 2004).

The success of WAG injection over water and gas injections originates from two facts. Firstly, the residual oil in the flooded rock may be the lowest when three phases—oil, water, and gas—instead of two phases—oil and water or oil and gas—have been

Address correspondence to Mohsen Masihi, Department of Chemical and Petroleum Engineering, Sharif University of Technology, Azadi Ave., Tehran 11365-9465, Iran. E-mail: masihi@sharif.edu

achieved in the reservoir. Secondly, water injection alone tends to sweep the lower parts of a reservoir and gas injection alone sweeps more of the upper parts of a reservoir due to gravitational forces. By WAG injection, both the lower and upper parts of the reservoirs are swept. To comply with the world demand to reduce greenhouse gases, carbon dioxide is injected in a WAG injection mode (Sadooni et al., 2008).

2. Reservoir Fluid Modeling

The objective of fluid modeling is to define a tuned equation of state that can model the reservoir fluid in simulations. To fulfill this objective, and after choosing an equation of state (e.g., three-parameter Peng-Robinson in this case study), the parameters of this equation are regressed so the fluid model can match the experimental tests, such as differential liberation and constant composition expansion experiments and saturation pressure used in this research work. In this research PVTi software (Tehran, Iran) was used for the purpose of fluid modeling.

The fluid has 32 components. By using the grouping technique, the number of components was reduced to 14. Usually by considering the time-consuming process of simulation in field scale the number of grouped components is 7, but in this case because miscible injection is performed, at least 10 components are required (Danesh, 1998). For more precise results, the fluid was divided into 14 components.

The numerical values for the parameters used in the equation of states after regression are shown in Table 1. The tuned equation of state gave a precise match (less than 1% error) with the experimental saturation pressure. The phase envelope of the reservoir fluid is shown in Figure 1.

3. Slim Tube Modeling

Minimum miscibility pressure (MMP) is usually determined by slim tube experiments in industry. But because this experiment is expensive and time consuming, it can be

Table 1
Parameters of the equation of state after fluid modeling

Components	Mol. weight	Critical pressure, psia	Critical temp, °F	Omega A	Omega B	Accentric factor	Parachors	*V* crit, ft^3/lb-mol	*Z* crit
N_2	28	492.3	232.5	0.37	0.09	0.04	41	1.44	0.29
CO_2	44	1,071.3	98.8	0.45	0.08	0.225	78	1.51	0.27
C_1	16	667.8	116.6	0.6	0.11	0.013	77	1.57	0.28
C_2	30.1	733.8	90.1	0.48	0.08	0.098	108	2.37	0.29
C_3	44.1	637.9	311	0.3	0.07	0.152	150.3	3.2	0.25
C_4	58.1	564.3	416.7	0.29	0.07	0.197	187.6	4.12	0.25
C_5	72.2	421.9	522.9	0.33	0.08	0.24	228.6	4.96	0.2
C_6	84	367.1	638	0.34	0.08	0.288	271	5.62	0.18
C_7	96	362.9	730.9	0.35	0.08	0.29	312.5	6.28	0.18
PS1	127.5	313.2	873.2	0.35	0.08	0.354	391.9	8.18	0.18
PS2	218.2	218.4	1,110.9	0.35	0.08	0.533	555.2	12.56	0.16
PS3	294.2	170.8	1,286.9	0.35	0.08	0.699	752.5	16.7	0.15
PS4	331.2	157.6	1,348.2	0.35	0.08	0.766	826.4	18.32	0.15
PS5	450.1	82.7	2,497	0.34	0.09	1.904	1,136.9	27.13	0.07

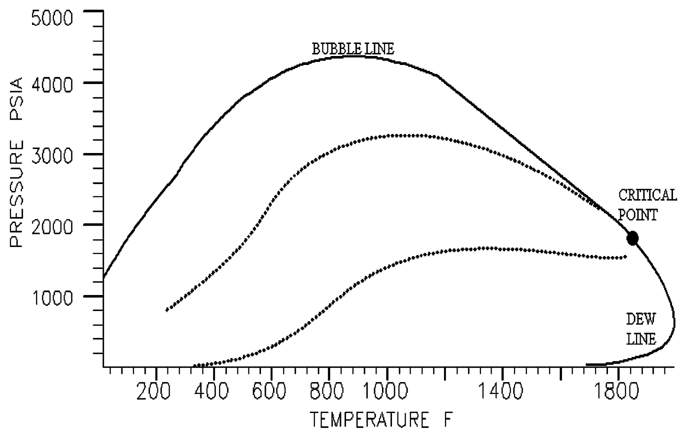

Figure 1. Phase envelope of the reservoir fluid.

simulated numerically. A cube with 2,115 cm length, 0.334 cm width, and 0.334 cm height was selected for this slim tube simulation using Eclipse E300 software (Tehran, Iran). Notice that the ratio of length to cross section should be high so that fingering effects are negligible. Porosity and permeability of this model are 30.9% and 8.9 Darcy, respectively. The slope of the tube was considered 5% in order to make the movement of oil by gas stable. Injection was done in the first grid and production in the last grid. Pressure decline in the tube was negligible.

This one-dimensional reservoir was firstly saturated with oil (modeled in the previous section) and then gas injection was started with a rate of 5 cc/hr. Pore volume is 73 cc; after 17.52 hr the injected volume reached 1.2 of pore volume. (It should be mentioned that the critical rate of injection for the miscibility with this oil is 51 cc/hr.) This work was performed for different pressures and the ultimate recovery was calculated. MMP was determined from the plot of ultimate recovery versus pressure (this graph for CO_2 is shown in Figure 2). MMP is the point where there is a break in the graph or the

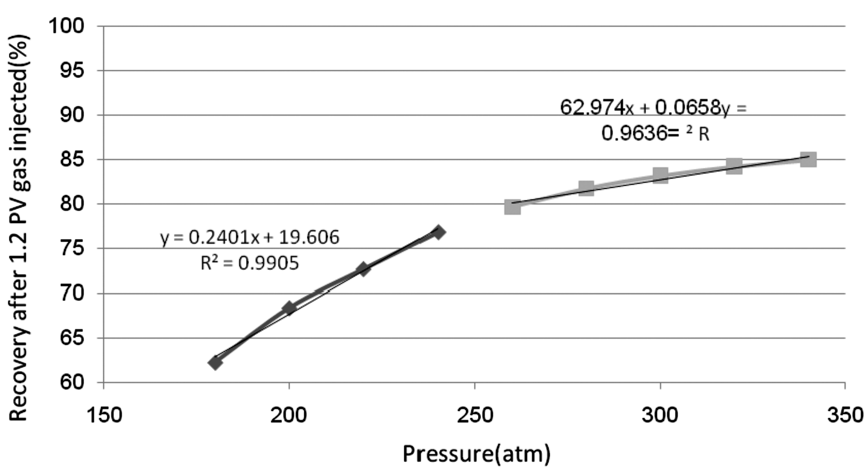

Figure 2. MMP calculation for carbon dioxide.

Table 2
Composition of natural gas of a close gas reservoir

Components	Mole fraction, %
N_2	26
CO_2	7.8
C_1	66.06
C_2	0.14

Table 3
Minimum miscibility pressure for different gases

Gas type	MMP, psi
Separator gas	4,520
Natural gas	5,021
N_2	5,934
CO_2	3,643

intersection of two regressed lines. Table 2 shows the composition of natural gas. Table 3 compares the calculated MMP for these four gases. As can be seen, CO_2 has the lowest MMP values and nitrogen has the highest.

4. Validation of Slim Tube Modeling

When the pressure reaches MMP, the further increase of the pressure ease has a slight impact on the total oil production. Figure 3 shows the cumulative oil production of the tube for the case of nitrogen. As can be seen, at the MMP value or higher pressures the total oil production trends are near each other.

Validation of the slim tube model can be tested more precisely by comparing the obtained MMP of the model with the MMP obtained by the correlations. MMP value in the case of N2 was calculated by some correlations and the results are given in Table 4. As can be seen, the average error percentage is less than 5%, which validates the simulated results.

5. Reservoir Description

M-field is located in the wrinkle area of Zagros in the direction of northwest to southeast in the northwest of giant Ahwaz field. This field consists of two formations: Asmari and Bangestan. No oil from Bangestan formation has been produced.

K-reservoir, which consists only of Asmari formation and was studied in this article, started production in February 1978. Initial reservoir pressure was 5,550 psi. K-reservoir has a strong aquifer and it is undersaturated with no gas cap. This reservoir is conventional and there are no signs of fractures in the reservoir.

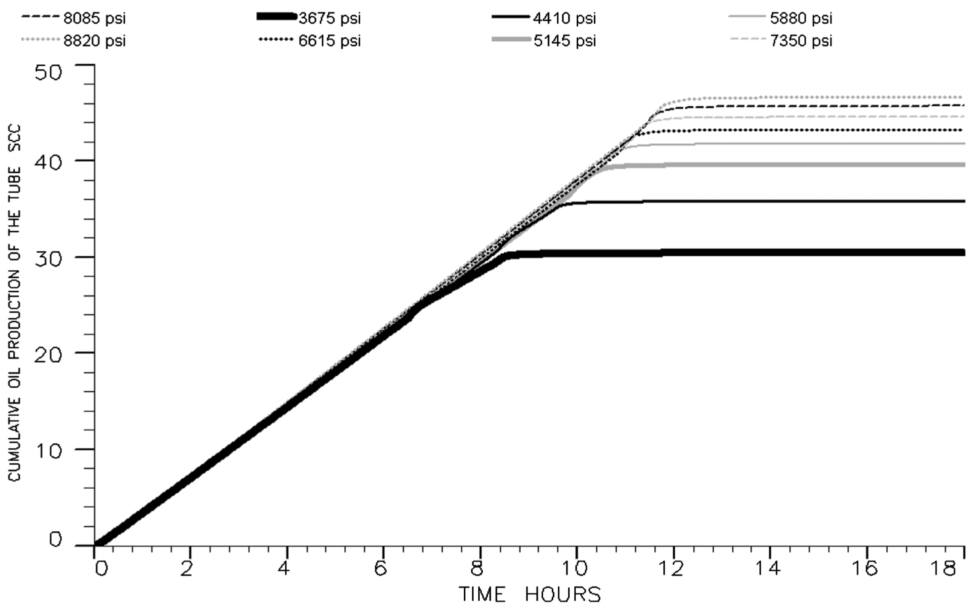

Figure 3. Total oil production of the tube vs. time for the case of nitrogen.

Table 4
Calculated MMP by the experimental correlations and the error percentage

Correlation	MMP, psia	Error, %
Firoozabadi and Aziz (1986)	5,850	1.42
Glass (1985)	6,424	8.26
Hudgins et al. (1988; Green and Willihite, 1998)	5,700	3.94
Sebastian and Lawrence (1992)	6,191	4.33
Average		4.49

K-reservoir has nine wells. Six of these wells are now under production and two are newly drilled and horizontal. The reported value for the maximum production from this reservoir is 41,000 barrel oil production per day (BOPD) and the average production is 30,000 BOPD. The reservoir rock consists of limestone, sandstone, dolomite, and shale.

K-reservoir has 40 grids in the *i* direction, 120 grids in the *j* direction, and 50 grids in the *k* direction. Due to this gridding, the total number of blocks is 240,000; 53,912 blocks are active.

6. Reservoir Simulation Scenarios

To study the miscible injection scenarios, 14 components were considered for the reservoir fluid. It is clear that the full-field simulation takes a long time and for more accurate

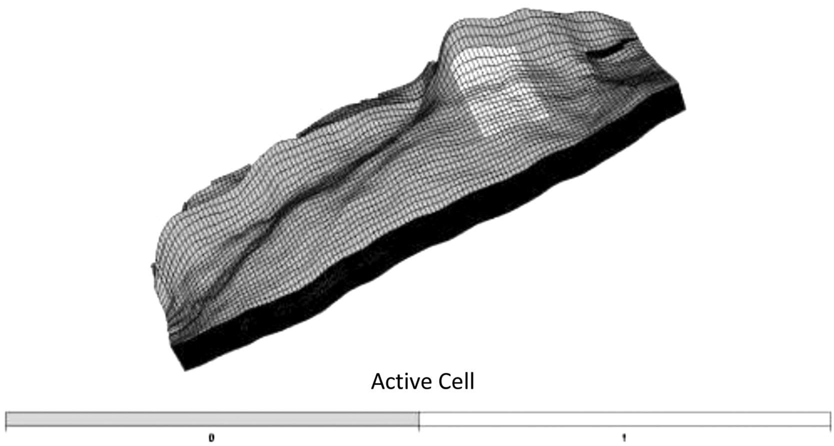

Figure 4. Position of the sector in K-reservoir.

investigation of various processes and parameters of K-reservoir, a sector of this reservoir was considered. Figure 4 shows the position of this sector in the reservoir. Three of the production wells are located in this sector, one of which is horizontal. One injection well was considered in the model. The locations of injection and production wells of the sector are shown in Figure 5.

Because the reservoir has a strong aquifer, we observed that the current production is in the plateau period. As Figure 6 shows in the case of natural depletion, oil production drops in 2014 and, therefore, different injection scenarios will start in 2013. At this time, the reservoir pressure is expected to be 3,650 psi and the only miscible gas between four tested gases in slim tube test simulation is carbon dioxide. Therefore, this gas was considered for injection in gas injection scenarios.

To perform the simulation, the E300 feature of Eclipse was used and the simulation was run up to 2040.

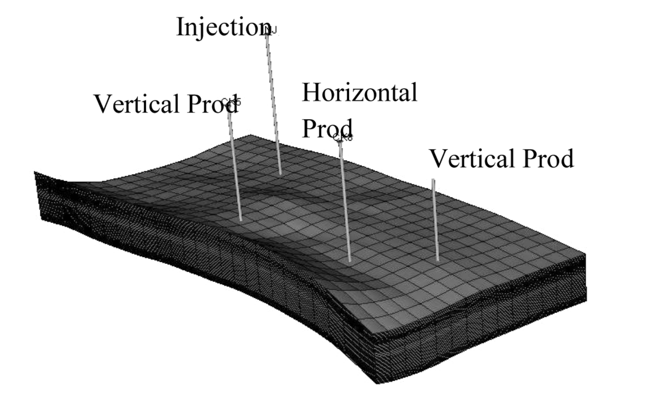

Figure 5. Position of injection and production wells in the reservoir (CK5, CK7, and CK8 are production wells. CK8 is horizontal.)

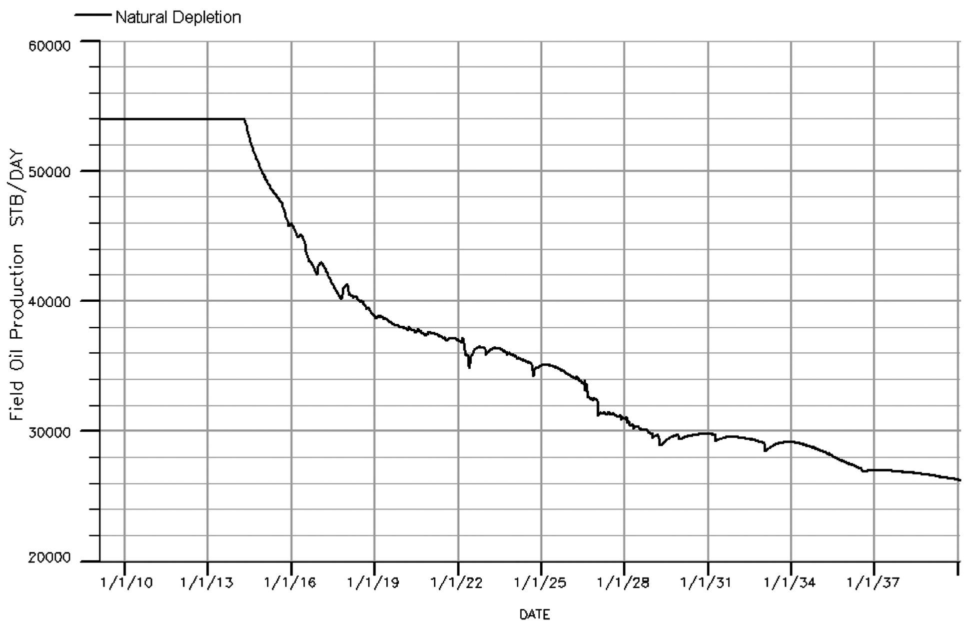

Figure 6. Oil production rate in natural depletion.

6.1. Water-Flooding Scenario

In this case, water was injected with the rate of 22,000 stock tank oil barrels (STB)/day starting in 2013. The water-flooding scenario improves the ultimate oil recovery in 2040 by 2% compared to the recovery obtained from natural depletion (i.e., 75% compared to 73%).

6.2. Water Alternating Gas Injection Scenario

Two main operational aspects that affect the economics of a WAG project are slug size of the half cycle and WAG ratio. Sensitivity analysis was done on these two parameters. WAG ratios of 1:2, 1:1, 3:2, and 2:1 were chosen. WAG half cycles of 0.5, 1, 1.5, and 2 years were considered.

These 16 scenarios were investigated and the results were compared. Recovery factors for different half cycles per WAG ratio are shown in Figure 7. As can be seen, the best case is the one with a half cycle of 1.5 years and WAG ratio of 1. For this scenario oil production is 84%, which is much more than the recovery from natural depletion (73%).

6.3. Hybrid WAG Scenario

This method is a continuous gas injection followed by the alternate injection of water and gas. In hybrid WAG up to 40% pore volume (PV) of gas is injected and is followed by the alternate injection of water and gas.

In this article, 40% PV of carbon dioxide, which is miscible with oil in reservoir conditions, was injected followed by water alternating gas injection. Gas injection rate

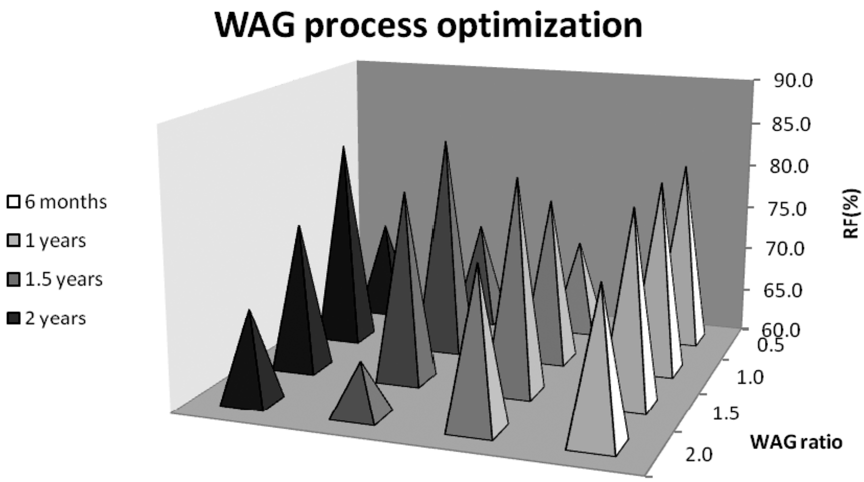

Figure 7. Recovery factor for different half cycles for different WAG ratios.

vs. date for this scenario is shown in Figure 8. Ultimate oil recovery of this scenario in 2040 is 74% and compared to the recovery from the natural depletion that may be economically invaluable.

From Figure 8, the rate of injection prior to WAG is very high (in order to inject 40% of pore volume). Therefore, there is not enough time for gas to become miscible with oil (i.e., the rate of injection is higher than the critical rate); as a result, the recovery is reduced.

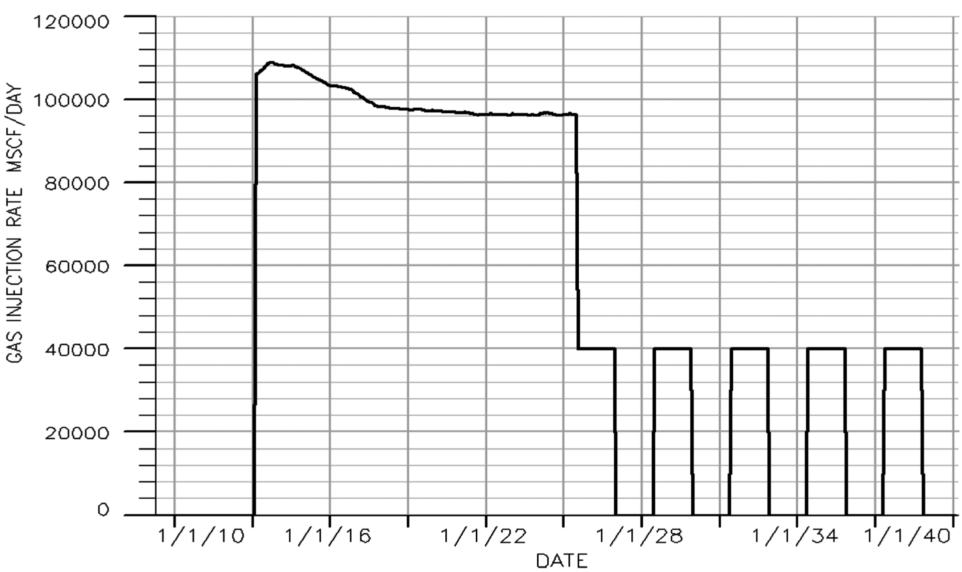

Figure 8. Injection rate of CO_2 vs. date for hybrid WAG scenario.

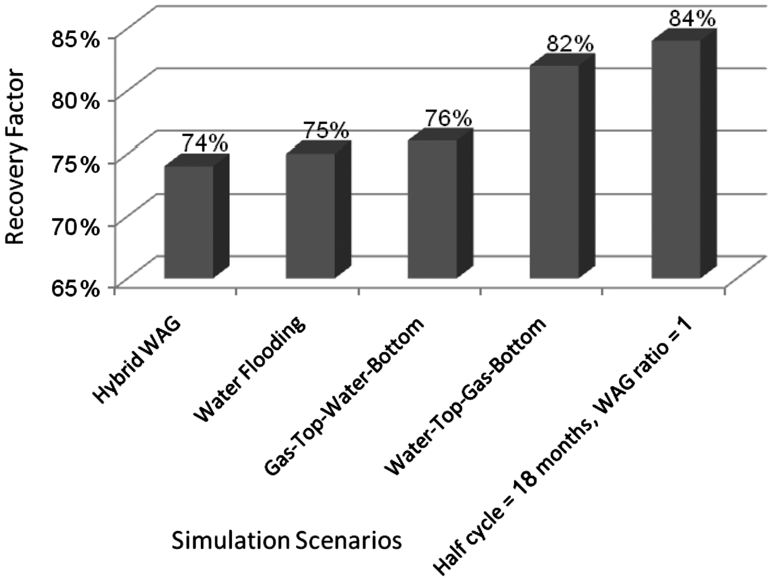

Figure 9. Recovery factor for different scenarios.

6.4. *Separate Injection of Gas and Water in the Top and Bottom of the Reservoir Scenarios*

Two cases, injection of water in the top and injection of gas in the bottom of the reservoir and vice versa, were studied. In the water-top–gas-bottom scenario, because of the gravity difference between water and gas, water moves downward and gas moves upward. This movement helps sweeping the pores. Therefore, in 2040, the water-top–gas-bottom scenario gives a recovery factor of 82%, whereas the gas-top–water-bottom scenario gives a recovery factor of 76%.

7. Comparison of Various Scenarios

Figure 9 shows the ultimate oil recovery in 2040 for the various studied scenarios. As can be seen, WAG has the highest recovery factor and hybrid WAG has the lowest. It should be mentioned that all of the injection scenarios gave higher recovery factors compared to the recovery from natural depletion (RF = 73%).

8. Economical Evaluation

Making a sound business decision requires that a project is economically viable. Economical assessment (Sattar and Thakur, 1994) based on the net present value (NPV) was done for the studied scenarios. Because the sector has three production wells and one injection well, we take into account these and other parameters for economical investigation. Operational costs and revenues were determined from 2013 to 2040. Table 5 shows the considered revenues and costs for WAG (half cycle: 18 months, WAG ratio: 1) as an example from 2013 to 2016. Similar calculations were performed for five other scenarios and NPV for these scenarios by assuming the interest rate of 10% as shown in Table 6.

Table 5
Capital costs, operational costs, and revenues from 2013 to 2016 for WAG scenario

No. of wells	4				
No. of compressors	1				
Well	$1,500,000				
Production facilities	$100,000				
Compressors	$1,000,000				
Daily costs	$1,000				
Oil price	$60				
Gas price	$4				
Water price	$0				
Water treatment price	$1				
Oil treatment	$3				
Years	2012	2013	2014	2015	2016
Wells	6,000,000				
Compressors	1,000,000				
Facilities	100,000				
Total investment	7,100,000				
Oil production rate		40,000	40,000	40,000	40,000
Gas production rate		22,252.73	40,462	25,763.44	39,852.7
Water production rate		54,344.98	62,380.73	75,619.01	77,381.27
Revenue	0	2,489,011	2,561,848	2,503,054	2,559,411
Gas injection rate		40,000	25,263.16	0	35,789.47
Water injection rate		0	8,105.263	22,000	2,315.789
Oil treatment	0	120,000	120,000	120,000	120,000
Water separation	0	54,344.98	62,380.73	75,619.01	77,381.27
Daily cost	1,000	1,000	1,000	1,000	1,000
Injected gas		160,000	101,052.6	0	143,157.9
Injected water		0	8.105263	22	2.315789
Total costs	1,000	335,345	284,441.5	196,641	341,541.5
Net revenue	−7,101,000	7.54E+08	7.97E+08	8.07E+08	7.76E+08

Table 6
Net present value for six different scenarios

Number	Scenario	Net present value, $
1	Natural depletion	4,403,179,207
2	Water flooding	4,493,837,239
3	Optimum WAG	5,271,305,165
4	Gas_Top_Water_Bottom	4,897,501,644
5	Water_Top_Gas_Bottom	4,960,247,925
6	Hybrid WAG	4,843,432,848

As can be seen, the WAG process and natural depletion are respectively the most and the least economically valuable scenarios.

9. Conclusions

1. Carbon dioxide has the lowest MMP compared to nitrogen, natural gas, and separator gas.

2. Simulation of the slim tube test can be validated by comparing the results with the approved correlations.
3. Sensitivity analysis of two main parameters of WAG shows that the best WAG scenario among 16 scenarios is the one with the ratio of 1 and a half cycle of 18 months.
4. Hybrid WAG with injection of 40% of pore volume at the beginning cannot achieve miscibility conditions and has a slight increase in the recovery factor.
5. Water injection in the bottom and gas injection in the top has a 6% higher recovery factor compared to the reverse situation. This is due to the gravity segregation in the reservoir.
6. Considering economical optimization for this reservoir, WAG has the highest NPV and natural depletion has the lowest NPV and all five of the investigated scenarios are more economically valuable than natural depletion.

Acknowledgments

The authors would like to thank the National Iranian Oil Company for allowing the use of their software.

References

Danesh, A. (1998). *PVT and Phase Behavior of Petroleum Reservoir Fluids*. Amsterdam: Elsevier Science.

Firoozabadi, A., and Aziz, K. (1986). Analysis and correlation of nitrogen and lean-gas miscibility pressure. *SPE Reservoir Engineering Journal* 6:575–582.

Glass, O. (1985). Generalized minimum miscibility pressure correlation. *SPE Journal* 6:927–934.

Green, D. W., and Willihite, G. P. (1998). *Enhanced Oil Recovery*. New York: Society of Petroleum Engineering.

Hudgins, D. A., Leave, F. M., and Chung, F. T. H. Nitrogen miscible displacement of light crude oil: A laboratory study. SPE paper No. 17372, *SPE/DOE Sixth Symposium on EOR of SPE and Department of Energy*, Tulsa, OK, April.

Kulkarni, M., and Rao, D. (2004). Is gravity drainage an effective alternative to WAG? *AIChE Annual Meeting*, Austin, TX, November 7–12.

Sadooni, M., Shahbazi, K., Hashemi, A., and Abdali, M. R. (2008). Evaluation of gas, water, WAG injections and infill wells for improving recovery of one of Iranian reservoirs. Paper No. SPE 116912. *Abu Dhabi International Petroleum Exhibition and Conference,* Abu Dhabi, UAE, November 3–6.

Sattar, A., and Thakur, G. (1994). *Integrated Petroleum Reservoir Management*. Tulsa, OK: PennWell Books.

Sebastian, H. M., and Lawrence, D. D. (1992). Nitrogen minimum miscibility pressure. Paper No. SPE/DOE 24134. *SPE/DOE Enhanced Oil Recovery Symposium,* Tulsa, OK, April 22–24.