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Modeling of Different CO_2 Injection Scenarios in One of the Iranian Oil Reservoirs

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Abstract: This studys aims to investigate and compare different gas injection methods in one of Iranian oil reservoirs that are done using Eclipse 300 Software. This study investigates recovery factor, cumulative recovery and the effective parameters of gas injection during different procedures of CO_2 gas injection and Water Alternating Gas (WAG) injection. At last, recovery factor and cumulative recovery are studied and compared during different WAG injection scenarios to specify an optimized pattern of injection. Laboratory data of reservoir rock and fluid are matched in PVTi Software and the results are imported into Eclipse for modeling miscible CO_2 injection and WAG injection. The results showed that oil recovery during WAG injection in reservoir and miscible CO_2 injection is 31.8 and 25.8%, respectively. In case if WAG injection is highly suggested instead of miscible CO_2 injection.

Key words: Miscible CO_2 injection, Water Alternating Gas (WAG) injection, enhanced oil recovery, suggested

INTRODUCTION

Gas injection is done as miscible and immiscible methods. Natural gas is enriched with middle hydrocarbons like C_2-C_6 at miscible injection method. Recovery increase rate is the maximum at this method and nit can cause a recovery of about 65-75% of residual oil, if reservoir rock has homogeneous characteristics and good permeability (Kulkarni and Rao, 2005). At CO_2 injection lots of this gas is injected into reservoir along with some fraction of light hydrocarbons for miscible sweeping. This method usually is used for the reservoirs that reservoir initial pressure is decreased during initial production or waterflooding. In this method, water is injected into reservoir until pressure reaches to an acceptable amount. Then, CO_2 is injected through injection wells. During this injection a miscible area of CO_2 and light hydrocarbons is created which is soluble in oil and speeds its movement toward production wells. Another injection method is Water Alternating Gas (WAG) injection which is done in large scales in oil fields for controlling oil mobility. WAG injection was first attempted at 1957 in Alberta and the results were reported as successful (Quijada, 2005). After this and because of its numerous privileges comparing to water or gas injection separately it has been applied around the worldwide like USA, Canada, North sea, Russia, Turkey and Venezuela. The mentioned privileges include high capability for controlling mobility ratio of displaced and displacing phases, preventing immature fingering in production wells, capability of recovery of un-swept oil during water or gas injection, creating a controllable and stable front and capability to use operational tools of water and gas injection for different oil fields. During these years researchers investigated different aspects of WAG injection for better understanding of the facts and the changes of reservoir properties during injection period. Cobanoglu (2001) investigated immiscible gas and WAG injection in BatyKozulca in Turkey with designing and comparing different scenarios of injection rates, cycles and number of producing and injecting wells using Eclipse 100. The results of their study showed that immiscible WAG injection led to more oil recovery comparing to immiscible gas injection. Klov and Hustod (2003) investigated WAG injection and compared its results to injection of gas and water separately in high permeability layers of North Sea field. They claimed that fingering of gas and water at high permeability layers and immobility at low permeability layers causes a low recovery during these methods. Their studies showed that WAG injection prevents the movement of gas in high permeability layers and creating a 3 phase area and

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stability of mobility front. Therefore, this method shows a higher recovery comparing to injection of water or gas. Jaturakhanawanit and Wannakomol (2011) studied gas and WAG injection in Phitanulok field at North of Thailand. They claimed that with an optimum injection rate of 700 bbl/day of water and 700 Mf^3/day of gas with a 12 month cycle of water and 1 month gas, the achieved recovery would be 65 and 28% for WAG and gas injection, respectively. Christensen *et al.* (2001) investigated a 30 year period of seelington field at Texas. They introduced an immiscible simultaneous injection of water and gas as an optimum method for the mentioned reservoir. Maracaibo field was studied by Manrique (2000). The results showed that WAG injection will increase oil recovery about 17% at that field. Shi *et al.* (2008) investigated kuparuk field at North of Alaska by using data from a 20 years period of WAG injection. They claimed that although gas injection is used as EOR method in this field but because of immature fingering and GOR increase, WAG injection was suggested and replaced w andith that method to prevent those problems. That also increased oil recovery. Instefjord and Todnem (2002) studied a 10 years period of WAG injection in Gullfaks field. His studies showed that during injection in this field, oil production was almost 2 MMSTB more than natural production. He claimed that WAG injection in this filed led to increase of recovery, sweep efficiency and water cut. Other than these mentioned reports, there are so many successful reports published about WAG injection and its privileges comparing to EOR other methods (Rogers and Grigg, 2000). In the last decade almost 40% of gas injection projects at different countries like Turkey, Russia, Canada, Norway and, etc. were as WAG injection and 80% of them are reported as successful (Rehman, 2008).

MATERIALS AND METHODS

Reservoir modeling: The first step for reservoir simulation is to obtain the data that are needed for reservoir modeling. Initial conditions of the reservoir are:

- Initial water Saturation (S_w): 15%
- Reservoir initial Pressure (P_i): 4335 psi
- Reservoir Temperature (T) 302 F
- Bubble Pressure (P_b): 2673 psi
- Water Oil Contact (WOC): 6849 ft
- Gas Oil Contact (BOC): 2000 ft

For the simulation, the studied field should be converted to a model for importing to Eclipse 300 simulator. A cubical model is created for this purpose.

Table 1: Information of the studied reservoir

Parameters	Unit	Amount
Reservoir depth	ft	6167.1
Reservoir length	ft	135000
Reservoir width	ft	150000
Reservoir thickness	ft	100000
Permeability of x and y direction	mD	179.23
Permeability of z direction	mD	17.943
Porosity	Percent	25.560
Lightness	API	46.000
GOR	SCDF/STB	240000
B_o	Rb/STB	2.9000

After analyzing the effect of grid numbers on simulation result, the following numbers for grids are chosen:

- Grid numbers at x direction: 21
- Grid numbers at y direction: 24
- Grid numbers at z direction: 4

The relative file for field grids is GRID. GRDECL that is created by FloGrid Software. The PERMX. GRDECL is the file for permeability information at x direction and as the same, PERMY. GRDECL is for permeability at y direction.

Table 1 shows petro physical characteristics and the information obtained from PVT test in simulator. The layer has a low thickness of 100 ft that shows the reservoir has several layer. The permeability in x and y direction is 10 times of the permeability of z direction ($K_x = K_y = 10K_z$).

Operational conditions of model: For prediction of reservoir operation for simulator, it is necessary to define some limitations and conditions. These limitations for economical production and of probable limitations of wellhead facilities and preventing their damages are considered during simulation and applied for all scenarios. They include:

- Minimum economic production from each well: 100,000 bbl
- Maximum GOR of each well 3,000 SCF/STB
- Maximum water cut: 50%
- Abandonment pressure: 1500 psi

The production is from 9 producing wells at the start. EOR process and field development will not take place until 10 years and during this time the only production mechanism is natural production. For continuing field development 1 well will be drilled each 2 year until 20 year; one well as producing well and one as injection well. Cross sectional view and position of 20 producing and 10 injection wells are shown in Fig. 1.

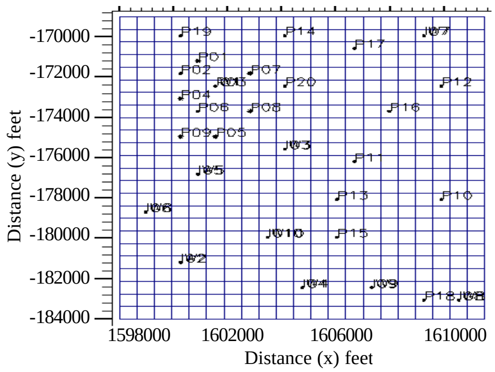

Fig. 1: Position of producing and injection wells

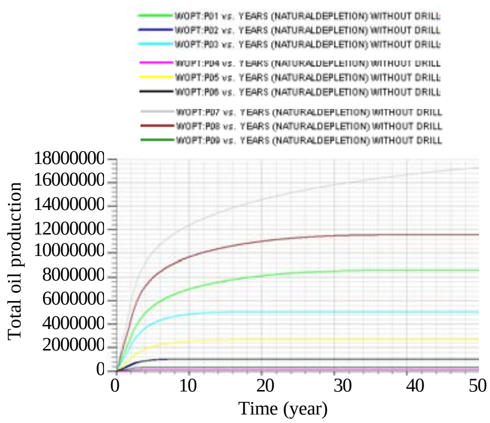

Fig. 2: Economical production limit of field wells

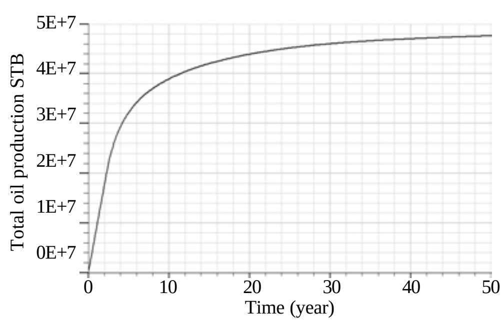

Fig. 3: Cumulative production during natural depletion mechanism without drilling new production wells and EOR operation

The second 10 years period is divides to 4 scenarios that 3 of them are investigated in this study. The second step will be studied in future works. These for scenarios include:

- Continuing production without drilling new wells and without EOR operation
- Continuing production with drilling new wells and without EOR operation

Table 2: Summary of 50 years of production from reservoir without drilling new wells and EOR operation

Parameters	Unit	Amount
IOIP MMbbl	438.16	
Oil recovered	MMbbl	47.610
Oil recovery factor	Percent	10.860

- Continuing production with drilling new wells and CO_2 gas injection
- Continuing production with drilling new wells and WAG injection

Production as natural depletion mechanism without drilling new wells and EOR operation: As mention earlier economical production from each well is 100,000 bbl per day. Figure 2 shows that all wells are reached to this limit and well #7 is best well. Bottomhole pressure is set to 1500 psi for ensuring that oil reaches to wellhead facilities and average production rate of each well is set as controlling rate. Figure 3 shows the results of running the simulator for 50 years of production. The results for 50 year of production with this mechanism are summarized in Table 2.

RESULTS AND DISCUSSION

Recovery with CO_2 gas injection: Gas injection is a common method of EOR operations. Displacement factor highly depends on minimum miscible pressure; a pressure that less than this pressure, the injected fluid is not miscible with oil. In this study, miscibility or immiscibility of operation is determined using PVTi software and reservoir data. Minimum miscibility pressure is determined via slim tube method of Eclipse software and this pressure is compared with maximum injection pressure that is determined by formation break pressure (Fig. 4).

According to empirical equations from well loggings of layers show that formation break pressure gradient is about 0.75 psi/ft for this formation. So, it would be about 4625 psi. Therefore, injection operation should be done in pressures lower than this amount.

Another effecting parameter is gas injection rate and in Fig. 5, it is shown that with increasing inection rate from 1000-4000 Mmcuft/day the recovery will increase from 26-33%.

In this study, we continue the simulation with 1000 Mmcuft/day to keep the calculations of GOR and other limitations for future studies. Figure 6 is results of this operation. Table 3 shows the summarized results of CO_2 gas injection scenario in reservoir.

Production during WAG injection scenario: The effect of each parameter isn't known very well in WAG injection operation. In this study, several parameters such as water/gas ratio, injection rate and types of injection are investigated.

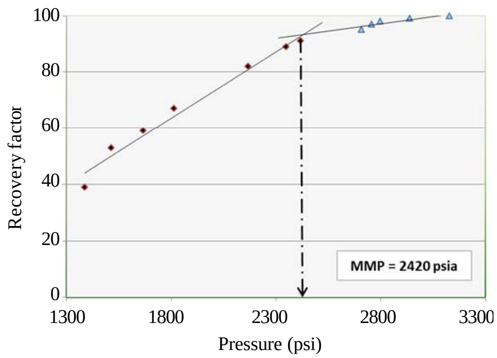

Fig. 4: Diagram of slim tube simulator for calculating minimum miscibility pressure. This minimum miscibility pressure is about 2420 psi for CO_2

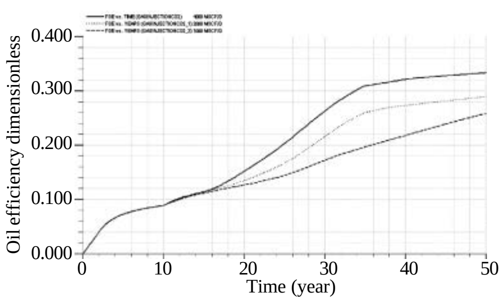

Fig. 5: Effect of different CO_2 injection rates on oil recovery

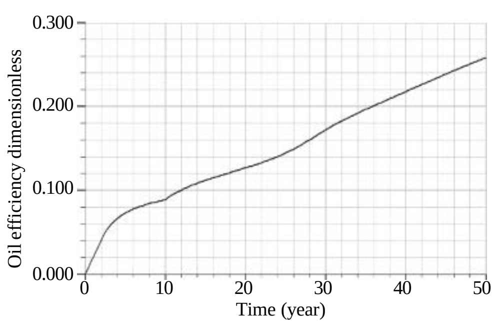

Fig. 6: Oil recovery during CO_2 gas injection scenario

Table 3: Summary of results of CO_2 gas injection scenario

Parameters	Unit	Amount
IOIP	MMbbl	438.16
Oil recovered	MMbbl	109.37
Oil recovery factor	Percent	25.840

Water/gas ratio: WAG ratio means the ratio of total injected volume of water and gas and its optimum amount depends on rock wettability.

However, 1:1 ratio is the most common ratio that is used. High amounts of this parameter have a great effect on recovery from water wet reservoirs. Its optimum amount during WAG injection depends to injected gas slug volume. With injection of slugs with a volume of 60% of pore space (0.6 PV) the recovery would be great. However, injection slug with a volume of 0.2 PV will be more economical. For oil wetting rocks the suggested ratio is 0:1 (continual gas injection) and for water wet rocks is 1:1 WAG injection. For investigating the effect of water/gas ratio injection rate of 4000 MSCF/day is selected and the diagram of oil recovery changes for water/gas ratios of 0.5, 1 and 1.5 (water injection rates are 2000, 4000 and 6000 bbl/day, respectively) are calculated. Figure 7 shows the oil recovery for different injections during optimum 1:1 injection.

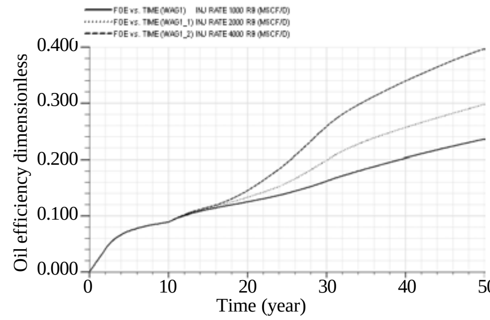

Fig. 7: Effect of injection rate on oil recovery

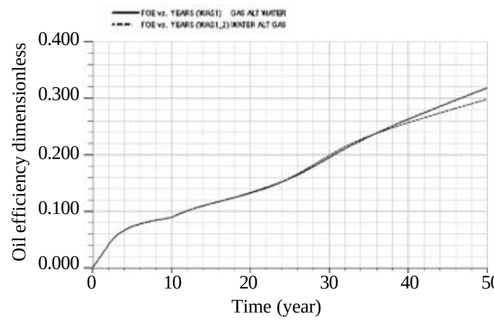

Fig. 8: Effect of injection type on oil recovery

Effect of types of injection: According to reservoir rock properties, two types injection can be applied. For the first method, gas injected into reservoir earlier than water and for the second method it is water earlier than gas. When water injected firstly (second method) oil would be trapped in pores if the reservoir is water wet and it will decrease recovered oil. Figure 8 shows oil recovery in case that gas is injected earlier that water (first method). The reason for this can be because of water wetting behavior of reservoir rock. According to analyzing sensitivity measurements the effective parameters on EOR are optimized as following:

- Water/gas ratio: 1:1
- Injection rate: 2000 bbl/day water and 2000 MSCF/day gas
- Injection type: gas earlier than water (first method)

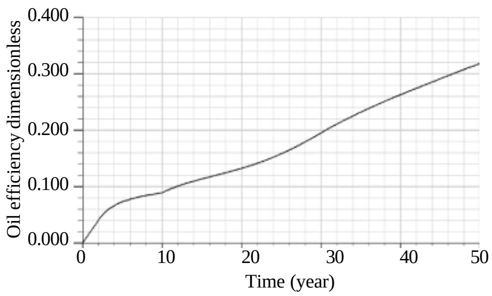

Fig. 9: Oil production during WAG scenario

Table 4: Results of WAG injection scenario

Parameters	Unit	Amount
IOIP	MM bbl	438.16
Recovered oil	MM bbl	136.72
Oil recovery factor	Percent	31.80

The results of optimized parameters are shown in Fig. 9 for injection cycle of 6 months and they are summarized in Table 4.

CONCLUSION

In this study, one of Iranian oil fields is studied. For predicting reservoir fluid properties PVTi is used for making reservoir fluid model. After that, using Eclipse 300 Software a cubical model with compositional simulation approach is created. Operational conditions and different scenarios for production from reservoir are introduced:

- Results of the simulation shows that WAG injection is strongly suggested comparing to continual injection of gas
- Results of sensitivity analysis for CO_2 gas injection rate showed that with increasing injection rate oil recovery increases but this injection rate increase is allowed until it is possible and economical
- Sensitivity analysis of WAG injection studied by parameters such as water/gas ratio, injection rate and injection type. The 1:1 ratio with injection rate of 2000 bbl/day water and injection of gas earlier than water (Gas alternating water) were the results of this analysis
- According to the results from investigation of this field and considering low oil recovery during natural depletion (about 12%) EOR methods should be applied

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