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Research Article

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Simulation Study of Miscible and Immiscible Injection of Carbon Dioxide into an Oil Reservoir in Iran

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ABSTRACT

After the primary and secondary recovery processes, about 50 percent of the oil remains inside the reservoir. This oil can be the source energy for a year. Although the production of the all trapped oil is a difficult task, but it is among a reservoir engineer's purposes and using the Enhanced Oil Recovery (EOR), much of this oil can be produced. One method that has a great impact on the trapped oil is the injection of carbon dioxide. This study examines the performance of carbon dioxide in one of Iran's tanks. Miscible and immiscible injection of carbon dioxide into the reservoir causes pressure consolidation and pushes the oil in the reservoir. It also causes an increase in oil recovery and is environmentally significant. In this study, using the software Eclipse 300, the natural production and injection of carbon dioxide is examined. The oil in the tank was analyzed by the software PVTi and experiments such as constant volume expansion and phase release were carried out on the oil. The software PVTi output was used as the software Eclipse 300 input. MMP was determined by three methods. The simulation of carbon dioxide injection was performed by the software Eclipse 300 the results of which showed that the six-well model has the highest natural production. The injection of carbon dioxide and that of carbon dioxide and water intermittently were performed and the latter showed a better performance than the former.
Keywords: *miscible injection, immiscible injection, carbon dioxide, oil reservoir*

INTRODUCTION

Today, fossil fuels provide 85 percent of the world's energy. Recently, we have observed the production of about 87 million barrels per day and, thus, 32 billion barrels per year in the world. This means that, to replace the depleted reservoirs, every year the oil industry finds oil twice as much as the volume of residual oil in the North Sea. Of 32 produced billion barrels per year, nearly 22 billion barrels come from sandstone reservoirs. The reserves and production rates in sandstone reservoirs takes nearly 20 years from production to evacuation, but in carbonate reservoirs, it takes 80 years from production to evacuation (1). Considering the global energy demand and consumption rate, a rapid rise is predicted over the next 20 years; therefore, we must be searching for a more practical solution to confront this growing demand. The practical solution is the continuity of oil production in existing fields because the industry cannot guarantee new explorations since they are likely to lead to deep marine oil fields where a lot of production problems are big obstacles. Also, production from non-sandstone resources, due to its EOR (Enhanced Oil Recovery) method, will be more expensive than from the existing reservoirs. The total oil discovered until 1993 was 536 billion barrels; the total production was 162 billion barrels (30% of the total discovery); and the reserves were 23 billion barrels (percent of the total discovery). This is the amount that can be economically produced by the conventional methods. The residual oil in the reservoirs is 351 billion barrels, or 66 percent of the total discovered. If EOR can increase half (i.e., 176 million barrels) of the remaining reserves, then, our recoverable reserves can be predicted twice as much now. Similarly, two trillion barrels will be added to the reserves worldwide. When the reservoir has enough energy and it produces through its natural energy, the production is called primary recovery. After a while and due to production, the energy of reservoir is reduced and, then, the production from the reservoir is not economical any more. At this point and for larger production, the necessary energy must be provided from outside the reservoir through injection; this stage is called secondary recovery. This means that we are facing with reservoirs that have not lost their potentials but do not have the energy to produce oil. Secondary recovery can be divided into two categories: gas injection and water injection. Sometimes, oil production would not be economic even through secondary recovery. For example, there is a well to which water is injected and another well from which oil is produced and water causes oil movement from the injector. But after a while, water creates a canal, i.e., the water is injected from one side and comes out from the other side. Or water-oil ratio is so high that the operation is not economic. At this point, to produce oil from the reservoir, tertiary recovery methods are used such as carbon dioxide injection and injection of material to reduce the surface tension and... .

To enhance oil recovery, there are various methods in the today's world and they differ from one another according to the characteristics of each oil reservoir. Hence, finding the optimal method to enhance oil recovery from reservoirs requires comprehensive studies. Therefore in this project we tried to examine the EOR (enhanced oil recovery) method by Smart Water. Oil recovery is traditionally divided into three categories: primary, secondary, tertiary. The first phase of production from oil reservoirs is primary recovery done by the primary energy of the producing reservoir. The second phase begins with the reduction of the reservoir primary energy. Water flooding and gas injection are common processes in this stage. Today in many sources, water flooding is considered synonymous with secondary recovery. After the secondary phase is finished, the oil production becomes non-economic. However, there is still a lot of oil left in the reservoir that can be produced. As a result, efforts have always been done to increase the recovery by means of tertiary methods. Tertiary recovery is, in fact, the third phase of production and is executed after the secondary recovery process. This phase includes EOR methods and improved oil recovery methods. The EOR methods chemically affect the reservoir and they include miscible and immiscible gas injection, chemical and thermal methods.

If gas is injected into the oil layer, the method is known as EOR and can be done in two ways: miscible and immiscible gas injection. In the miscible method, natural gas is enriched by adding mid hydrocarbon compounds C2 to C6 so that the enriched part of the gas injected at the beginning is mixed with the oil in reservoir and leads it through the pores of the reservoir rock into the production wells. In this method, there is the highest percentage of increase in recovery efficiency. In case the reservoir rock has homogeneous properties and also a suitable permeability, 65 to 70 percent of residual oil can be achieved. In immiscible method, gas is injected into oil reservoirs. The injected gas is compressed in the gas cap or in the oil column and the pressure of reservoir increases. Immiscible injection in the oil layer is applied in the reservoirs with thin oil columns and low slope in order to provide pressure and to displace oil towards the production wells. In the reservoirs where natural production is affected by soluble gas drive mechanism, this method is more frequently used. Injection is also applied in the gas cap of the reservoirs with high permeability and low-viscosity oil. Miscibility or immiscibility of the injection process depends on the pressure conditions and composition of the oil in the reservoir and also on the pressure and composition of injected gas. And in case miscible gas injection is performed, it is necessary to know the mechanism of fusion of the injected fluid and vaporization or condensation. It is noteworthy that gas injection is considered as a convenient method to stabilize the pressure; to produce oil, as well as a suitable method to recover the residual oil after water injection. Restrictions of gas injection mechanism include poor sweeping efficiency of gas (because gas mobility ratio is higher than that of oil and it is much bigger than one); the high cost of the compressor (compared to pumping water); and the possibility of using gas as a new and cheap fuel source. On the other hand, gas availability; its low cost; and environmental issues related to the oil industry have attracted more attention to gas injection processes. Studying the injection of carbon dioxide at the temperature 101 ° C and in pressure 41/12 mPa, Zain and his colleagues (2) pointed out that although in the operating conditions, perfect miscibility cannot be achieved, extra oil production is possible. Anyway, according to these experiments, carbon dioxide has the ability to extract the hydrocarbon components heavier than C7. In the multi-contact miscibility of carbon dioxide injection, the middle and heavy hydrocarbon components are extracted in the enriched carbon dioxide phase. Under these conditions, the enriched phase of carbon dioxide can be miscible with the oil in the reservoir. Miscibility in the condition of carbon dioxide injection results in enhanced oil recovery: However, due to high mobility of carbon dioxide, low sweeping efficiency has been reported. Nevertheless different injection strategies can help solve this problem (3). Miscible and immiscible injection methods are highly important and applicable in oil industry in the recent years due to gas availability; ease of operating conditions; and availability of equipment. CO2 is one of the gases that have recently been taken into consideration due to its low miscible pressure; its ease of access; as well as fewer environmental problems. Therefore, this research studied the miscible and immiscible injection of CO2 into one of the reservoirs in the southern Iran.

Methods:

The first step in simulation of oil reservoirs is providing the basic properties of rock and fluid. This means that the dynamic and static properties of the reservoir have to be determined so as to predict the future of the reservoir. For reservoir simulation studies, a three-dimensional reservoir model was made based on a real model. The definition of the model is based on a real production field. Given that the permeability and porosity data have been entered into the software as a map, the model is a realistic one with heterogeneity which according to its specifications can be a good description of the actual reservoir behavior in the future. The initial reservoir pressure is 4500 psi. In this model, the structure Corner Point Grid has been used. Also, reservoir empty space volume is almost 622 MMrb and the initial average oil saturation is about 78/0 because the studied part of the reservoir is located in the oil region. The distribution of primary oil has been shown in the figure below. This model includes 10×34 ×30 grid blocks in which all blocks are active. The dimensions of each grid block in directions x and y is not clear according to the Corner Point. The built fluid model was used to simulate carbon dioxide injection experiments including inflating oil; determining miscibility pressure on the first contact; and determining miscibility pressure during next contacts. In order to identify the fluid, various experimental tests have been carried out on the reservoir fluid. Among the performed tests are constant composition expansion (CCE), detailed liberalization (DL), the constant volume distension (CVD) and flash vaporization. Miscibility in carbon dioxide gas injection process usually does not occur in the first contact especially in the real reservoirs where miscibility is achieved in multiple contacts and in the process of simultaneous drifting of liquefied and evaporated gas (4.5). Minimum miscibility pressure (MMP) has been calculated by experimental, analytical and, numerical methods. It should be noted that using experimental relation method is considered as the primary estimation in calculating the MMP. The best statistical parameters were achieved in Holm and Jozendal relations that estimate MMP with an error of 493 psia. Using the Yuan relation in analytical method, the amount of MMP has been calculated 3103 psia.

The average absolute error of this relation is about 10% which occurs within the error percentage of slim tube experiment (38). Another method is the use of state equations. To this end, the software is used in which calculations are done based on one of the valid state equations. We calculated the multi-contact miscibility pressure using software PVTi. The condensing multi-contact miscibility pressure was calculated 5369 psia by the software. Of the most important numerical methods to determine MMP, combined and one-dimensional simulations such as slim tube experiment can be mentioned. The slim tube model was designed 10 feet long and with 100 cells. Each cell was 0.1 long, and the current difference between the two heads of the model was assumed negligible. At different pressures, the injection uptake was calculated 1.2 pv, and eventually the multi-contact miscibility pressure was computed 5260 psia. Multi-contact miscibility pressure was obtained through three experimental, analytical and numerical methods and under reservoir conditions. The results are shown in Table 1.

Table 1: Results of multi-contact miscibility pressure tests

Methods	Miscibility pressure (psia)
Experimental	5580
Analytical	5369
Numerical	5260

According to the results, miscibility definitely occurs at pressures above the 5600 psia.

Findings:

In this study, using the software Eclipse 300, we undertook to predict the future of oil reservoir in the southern Iran through the miscible and immiscible gas injection methods. In all of the defined scenarios, the reservoir first produces naturally for 10 years. To determine the carbon dioxide injection scenarios, first, the following factors have to be measured in comparison to the normal production: reservoir conditions in terms of the ultimate recycling; production rate; the number of wells; and reservoir pressure. Then, it has to be decided how to perform the carbon dioxide injection scenario. Production was carried out using the natural energy of the reservoir and through 5 different production patterns. The double square and hexagonal 3, 4, 5 and 6-well patterns were used.

Natural Discharge of Reservoir

Natural discharge was performed by natural energy of the reservoir and the well bottom pressure of 1000 psia through five listed patterns. According to the findings, the highest cumulative production was achieved through the double square 6-well pattern producing about 14 million barrels of oil. One of the reasons for higher production in this pattern was the number of wells which affects a further depleting radius in the reservoir. Moreover, with decline in the energy of reservoir, the producing rate also falls. In the natural depletion of reservoir, the producing rate decline is inevitable because the reservoir pressure begins to decrease. But, among the natural discharge patterns, the greatest decrease of flowrate pattern was associated with the square six-well pattern; however, despite this flowrate decline, it still had the highest rate of production among all patterns and at the end of 60 years of simulation, the flowrate was about 440 stb / day. According to the findings, the lowest pressure drop was related to the three-well pattern and at the end of simulation; the reservoir pressure, from 4080 psia, reached 4360 psia. And the highest pressure drop was related to the six-well pattern in which the reservoir pressure reached 3890 psia. Due to the high pressure drop of the reservoir at end of the simulation, process of carbon dioxide injection should be started in the early years of natural discharge because the reservoir pressure has not yet dropped a lot and the miscibility can be successful. The highest production or the highest decline in residual oil of the reservoir occurred in the double square six-well pattern.

Continuous Miscible Injection of Carbon Dioxide

The miscible injection of carbon dioxide was performed continuously. For one-contact miscibility, an extraordinary primary energy is needed in the reservoir and in the examined reservoir, due to the initial pressure of 4360 psia; there is not sufficient pressure for one-contact miscibility. This important goal can be achieved by means of pressure stabilization methods, but the objective of this study is two-contact miscibility. In the scenario of miscible and continuous carbon dioxide injection, first, natural production was carried out for 10 years. And then, using the dual 5-point pattern and due to the better discharge of reservoir in the six-well scenario, carbon dioxide injection was conducted with a pressure of 7000 psia and continued for 50 years. According to the findings, at the end of the simulation, the pressure of grids has become more than 5600 psia and it represents the two-contact miscibility at the end of the simulation. So at pressures higher than 7000 psia, two-contact miscibility will definitely occur in the simulation. The injection was conducted within the pressures from 7000 to 15000 psia. First, the natural production from the reservoir was continued for 10 years and, then, carbon dioxide miscible injection was conducted for 50 years. The results showed that by increasing the pressure, cumulative production increased and the increase in oil production continued up to the pressure of 11000 psia and, then, it got nearly constant despite the growing pressure. Thus, the highest cumulative production is related to the pressure of 11000 psia. In all injection pressures, by increasing the injection pressure, production rate is also increased, but after a certain time, the rate is reduced. In this study, the further the injection pressure was increased, the more the production rate got, but at the same time, the sooner it reached to the decline time of rate. The production rate graph matched perfectly with the gas-oil ratio graph. In oil and gas production graph, the higher the injection pressure is increased, the sooner the wells are fumigated. So, it can be said that with increasing injection pressure, the wells are faster fumigated and, as a result, the oil production rate is faster decreased.

The Impact of Carbon Dioxide Injection Rate

One of the most important parameters in gas injection into the reservoir is the injection rate and it has a direct impact on recovery. That's why we must seek to optimize injection rate. Through a dual 5-point pattern, Carbon dioxide continuously and with different flow rates was injected into the reservoir. First six wells with bottom well pressure of 1000 psia were extracted for 10 years and then carbon dioxide was injected into them for 50 years. Table 2 shows the miscibility conditions at different rates.

Table 2: The Miscibility Conditions at Different Rates.

Injection rate (Mscf / day)	Type of miscibility
1000	immiscible
5000	immiscible
9000	miscible
13000	miscible
17000	miscible
21000	miscible

According to Table 2, at rates higher than 5000 Mscf/day, miscibility occurs. Based on the research findings, by increasing the rate the cumulative production increases. As anticipated, at rates that miscibility of carbon dioxide occurs, graphs are slightly different from each other. It can also be said that at the rate 7800 Mscf/day, miscibility happens. At the highest injection rate, i.e., the rate 21000 Mscf/day, the maximum cumulative production of 29 million barrels occurred; in other words, almost 19.6 percent of the residual oil was produced at this injection rate. Because of the high miscibility of carbon dioxide at rates higher than 7800 Mscf/day and restrictions of high rates, the most frequently chosen rate was 21000 Mscf/day. By increasing the carbon dioxide injection rate, production rate also increased, but the production rate increase was not stable. The production rate increases over time and until certain time and, then, it decreases again and the higher the injection rate is, the sooner the maximum rate is achieved and so is the rate decline. At all rates, first at a fixed gas-oil ratio, production occurs, but the higher the injection rate is, the sooner the gas breaking happens. Figure 5-18 shows this issue.

Carbon Dioxide Miscible Injection after Water Injection

One method of miscible injection into the reservoir is to inject water first to stabilize the reservoir pressure and then inject the gas. In order to stabilize the reservoir pressure, in any scenario, after 10 years of natural production for 25 years, water injection was carried out with a bottom well pressure of 11000 psia. The pattern of injection and production wells was dual 5-point pattern. Based on the results, the gas injection pressure, in injection grid, was greater than the miscibility pressure. Also due to the miscibility of carbon dioxide injection at all pressures, cumulative production figures are slightly different. The maximum cumulative production occurred at the injection pressure of 19000 psi containing 25 million barrels of oil. According to the findings, the production rate at high pressures produced at two different times: First, at the time of rate rise and, then, at that of rate decline, which is again dependent on oil and gas production graph. In natural production and water injection, the produced gas-oil ratio is constant; however, as we increase the gas injection pressure, the gas moves more quickly and the injected carbon dioxide reaches the producing wells and gas breaking occurs. Therefore, the higher the gas pressure is, the faster the gas breaking occurs and, as a result, the more gas is produced.

The Alternate Miscible Injection of Carbon Dioxide and Water

By removing the shortcomings of other methods such as immiscible gas injection and water flooding, water and gas alternate injection, i.e., a combination of water and gas injection, improves the production efficiency. That's why water and gas alternate injection has always been among the favored methods to develop and increase production in the most oilfields. The alternate carbon dioxide and water injection is performed because of the possibility of controlling movements and dynamics. When carbon dioxide gas is injected into the reservoir, it quickly turns around oil and reaches the production well, but the alternate miscible carbon dioxide and water injection decreases the injected gas mobility and, thus, has the highest efficiency and productivity. The alternate miscible carbon dioxide and water injection was done. First, the natural production was carried out for 10 years and, then, water and carbon dioxide were alternatively injected with different bottom-well pressures within two years. Results showed the alteration of the injected fluid during injection and the pressure increase above 5600 psia represents miscibility at this pressure. The pressure was also increased to the considerable amount of 27000 psia. The potential provided for this substantial increased pressure is due to the alternation of water and gas injection. The highest cumulative production was related to the pressure of 27000 psia that was the remarkable number of 36 million barrels of oil. The results of producing rate variations affected by increasing injection pressure were similar to those of the previous scenarios except that the maximum rate and, then, rate decline occurred within longer time from production and this could be due to gas mobility control. As a result, the gas breaking is delayed and the gas starts its internal production later.

Comparison of the Optimum Injection Scenarios

The most important stage of the simulation is to determine the best scenario for carbon dioxide injection. Carbon dioxide injection simulation was carried out through the following scenarios: the constant and miscible injection of carbon dioxide with different pressures; miscible and immiscible injection with different flow rates; carbon dioxide injection after water injection; and alternate miscible injection of carbon dioxide and water. The performance and productivity of the scenarios are compared in Table 3 and Figure 1 to 3. According to Table 3 and Figure 1, the best scenario for cumulative production was the alternate miscible injection of carbon dioxide and water which can be due to controlling the dynamism and mobility of the gas and, thus, producing less gas.

Table 3: Comparison of cumulative production in different scenarios

Scenario	Cumulative production (million barrels)
Natural discharge	3670.9
Miscible injection at different pressures	2847.29
Carbon dioxide injection at different rates	0346.29
Carbon dioxide injection after water	1201.25
Alternate carbon dioxide and water injection	1530.36

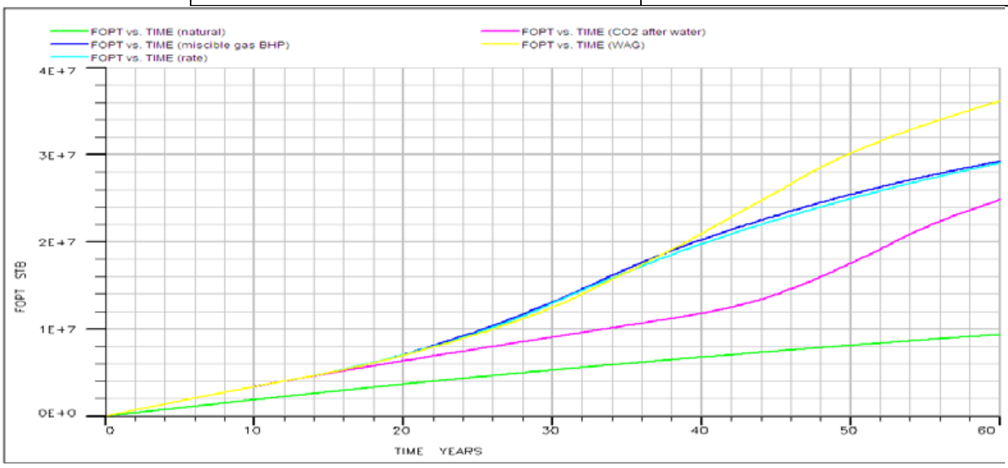

Figure1. Cumulative production in different scenarios

Figure 2 shows the reservoir production rate in different scenarios. According to the figure, the maximum production rate of about 2600 Mscf/day was related to the alternate carbon dioxide and water injection. Even when the rate dropped at the end of the simulation, it had a rate more than other scenarios and only the scenario of carbon dioxide injection after pressure stabilization with water at the end of the simulation had a more rate. Figure 3 demonstrates gas to oil production graph for various scenarios. According to the figure, after natural production, the scenario of alternate carbon dioxide and water injection had the lowest gas production. This is justifiable due to the water having been injected before gas.

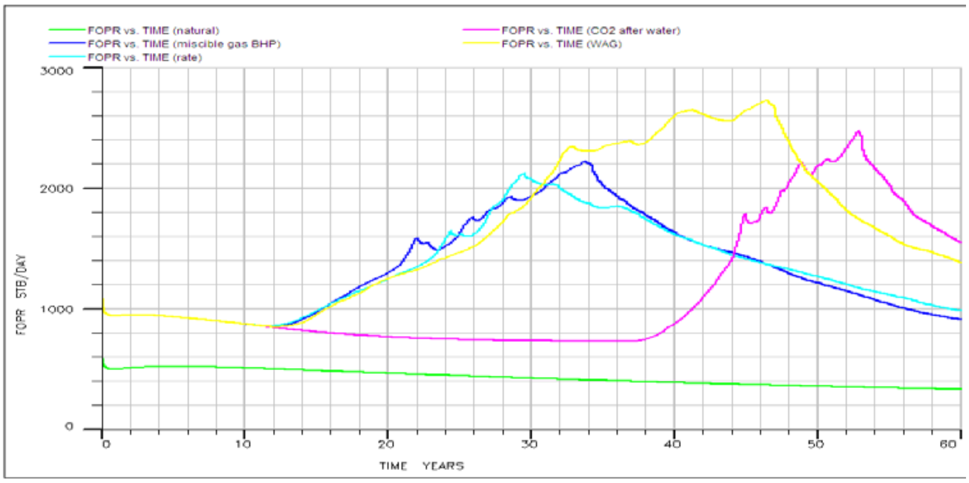

Figure2. The oil production rates for different scenarios

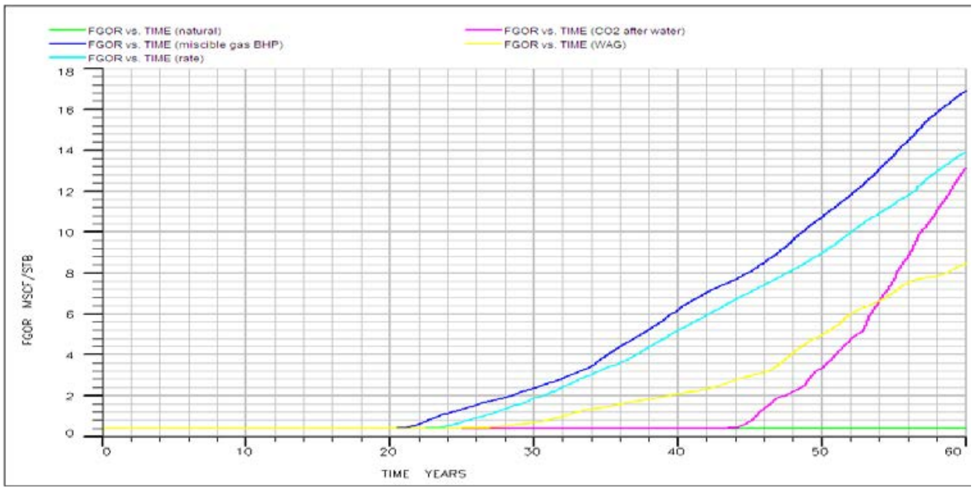

Figure3. Gas-oil ratio

Conclusion:

Miscible and immiscible carbon dioxide injection an EOR method used in oil reservoirs. Miscible and immiscible injection of carbon dioxide was performed in one of the reservoirs in southern Iran. It was successful and the following results were obtained. The oil in the reservoir was relatively light and the miscibility pressure (MMP) of carbon dioxide was almost 5600 psia. The increase in bottom-well pressure of carbon dioxide injection caused an increase in the oil recovery: This process continued up to the bottom-well pressure of 11000 psia and, then, cumulative production was nearly constant. In all scenarios of the carbon dioxide injection, the production rate graph would increase to a maximum point and, then, it would begin to drop. The rate decline was noticeable at high pressures. By increasing the injection pressure, the process of gas breaking took a shorter time. The rate of 7800 Mscf/day was chosen as minimum miscible rate (MMR). The increase in injection rate resulted in an increase in cumulative production. One way to stabilize the reservoir pressure is water injection. After natural production, water injection was performed to stabilize the reservoir pressure and, then, the miscible injection of carbon dioxide was performed. Increase in injection pressure of carbon dioxide enhanced the oil recovery. To control the carbon dioxide dynamics and mobility, the alternate injection of carbon dioxide and water was carried out which produced less gas. The alternate injection of water and gas was the best scenario that enhanced oil recovery the most.

Injection of carbon dioxide into the oil reservoir increased oil recovery, but given that the carbon dioxide injection in the reservoir still needs investigating, the following topics are recommended for further study: the ways of transferring carbon dioxide from the source to the wellhead; carbon dioxide effects on asphaltene precipitation; injection of carbon dioxide into the aquifer.

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