

Research Article

Technical Evaluation of Miscible Gas Injection Methods; Case Study in an Iranian Heterogeneous Carbonate Reservoir

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Abstract

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The reservoir under study is a reservoir with high amount of H₂S and asphaltene. It has more than 1 billion of Original oil in place as static geological model estimated but the problem is the only drive mechanism is Solution gas drive and it has no active aquifer so although it had good flow potential but what if it drops lower than bubble point pressure? Dynamic model showed it was to deplete quickly. By using new reservoir management techniques and enhanced oil recovery in order to pressure maintenance one can recover a lot more oil. The scope of this project was to evaluate in terms of impact of surface facilities, reserves and recovery factor of using gas injection and then different fluid composition for this field's gas injection (Rich gas corresponding to the associated separator gas to be re-injected to reservoir & Lean gas corresponding to the associated separator gas to be re-injected to reservoir after condensate removal). There are 40 wells in this fields and this was possible to change function of production well to injector if needed. After comprehensive study and technical evaluation it was found that. Miscible gas injection was the best scenario to Natural depletion.

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1. Introduction

Secondary recovery plays an important role in green fields. The goal of this study is investigation of several secondary recovery strategies in order to optimize of a carbonate reservoir with short production history.

Oil reservoirs, following discovery, undergo production of oil by primary recovery. In primary recovery, the energy and pressures inherent in the reservoir are used to force the oil through the complex pore network toward the producing wells. The primary recovery mechanism can differ from

one reservoir to another, depending on the type of reservoir and the properties of the rock and the hydrocarbons present. Following the primary stage, the reservoir energy is supplemented by the injection of water and/or gas in a “secondary recovery” stage. The ultimate oil recovery by primary and secondary recovery usually ranges from 25–45% of OOIP. As the secondary recovery approaches its economic limit of operation, the “tertiary recovery” process begins.

2. Field Background

This oilfield is a ramp type of carbonate reservoir that located in the Kuzestan Province in the petroliferous area of Dezful Embayment. The field structure is an almost symmetrical 4 ways dip anticline elongated in N-S direction with a smooth 5 degree inclination. Its closure, at the formation top (Target formation), is 22 km long and 8.4 km wide. The producing formation is composed of Limestone with alternations of porous zones (3 reservoir layers) and interbedded with mudstone and shaly limestone (interlayers). The deposition of the Formation occurred in the Berriasian-Valanginian Stage. The productive layers are mostly mud supported limestones, ranging from mudstone to wackstone. There are some sorted packstone-grainstone, fine peloidal packstone, root molds and alveolar septal fabric and mud supported limestone partially or totally dolomitised.

The original reservoir pressure was about 9500 psi with 300oF temperature. Twenty three high-pressure high-temperatures producing wells have been drilled in this field. In Figure 2 reservoir zonation are shown based on sedimentological structure. In each A, B and C layers there are leached zone at the top (light yellow) and one tight facies beneath (with dark yellow). In layer C, a water lens is also shown in Figure 2 (light blue) which is supported by no saline water production data from wells. The lens shape leached layer C is also verified in well logs. This leaching makes some secondary porosity which is called karstification. Under the karstified region the layers are dense with low hydrocarbon saturation. The pressure measurement shows that, the lower layers in some wells still have the original reservoir pressure, while the other layers have been depleted.

3. Reservoir Description

Core averages for porosity and permeability are 7.7% and 6 md but includes substantial zones greater than 30 md. The oil relatively light with API of about 34 degrees, viscosity of about 0.32 centipoises and solution GOR of 1100-1300 SCF/STB. The aquifer (water lens) is not very active and it can not maintain reservoir pressure during the course of depletion. In addition the reservoir pressure is higher than than the saturation pressure of the oil. Therefore the reservoir will become saturated after some

period of time, turning the reservoir from an undersaturated one phase fluid state to a saturated two phase fluid and solution gas will be liberated into the reservoir and a secondary gas cap will be developed. The expansion of this secondary gas cap will most likely adversely affect the ultimate recovery from the reservoir.

4. Field History

The field started to produce from 2003 with 25,000 bbl/day and currently is producing 100,000 bbl/day. The reservoir pressure currently has reached to 8500 psi down hole static pressure after more than 100 million bbl of oil production.

5. Process Description

Oil Field Development 2nd Phase consists the comprehensive plan to develop Field, to transport hydrocarbons from the production wellheads to the Plant for treatment and processing. oil, gas and water are obtained from incoming crude oil. Oil is delivered to export pipeline. Gas is re-injected. the facilities to re-inject water have to be foreseen but they will be installed in the future, when the water cut from wells will become relevant.

In this phase the produced water if any will be stored in an existing tank and removed by tankers. The plant shall be designed to produce stabilised oil. The plant will include all processing units, utilities, offsite facilities and associated infrastructures necessary to produce and export the oil and to re-inject associated gas and water in to the reservoir.

The facilities, product qualities and rates defined for “First Train Minimum Configuration” information as summarised below.

- Each train facilities are designed to produce 55000 STB/D (60000 STB/D peak rate – 50000 STB/D normal rate) from the feed composition indicated below.
- Condensate recovery and gas injection block flow diagram
- Rich Gas coming from Oil Treatment Unit is routed to Flash Gas Compressor and compressed up to about 75 barg;
- Compressed gas is treated in order to remove H₂S and then dehydrated before Condensate Recovery;
- Heavy fraction are (C₄+) are recovered, stabilised and cooled and then stored/exported;
- The lean gas resulting from condensate recovery is routed to Injection Compressors, compressed up to about 520 barg and reinjected into oil wells;

- The acid gas coming from Acid Gas Removal Unit is routed to Sulphur Recovery Unit where the sulphuric fraction is converted to Sulphur, which is stored/exported

Pressure losses in the tubing string were calculated at the different conditions on the basis of the Vertical Lift Curves as generated by Prosper software.

6. Drive Mechanism Analysis

Many sensitivity tests have been carried out in order to determine and to evaluate ultimate reserves and relevant production profiles according to different reservoir drive mechanism.

- Natural Depletion
- Gas injection with crestal injector wells
- Rich gas corresponding to the associated separator gas to be re-injected to reservoir
- Lean gas corresponding to the associated separator gas to be re-injected to reservoir after condensate removal

The objective of sensitivity runs was to determine the best drive mechanism to maximise the oil recovery. Therefore 40 years of field production life were considered.

6.1. Natural Depletion

Oil field depletion refers to the decline in an oil field's production over time, when a field's recoverable resources become exhausted and production is reduced due to the physical limitations of the reservoir. Depletion is a natural process by which an oil field produces an increasing volume of oil, that volume stops increasing and production hits a peak, after which the volume that can be pumped out of that field gradually declines. The analysis of depletion rates is a key element rates is a key element in forecasting the future production of oil reservoirs.

6.2. Water Injection

The goal of water injection was to prepare energy for the reservoir to produce oil by maintaining the pressure around the bubble point (with lowest possible viscosity or by sweeping oil with water when natural depletion could not occur. Important parameter in water injection study is Microscopic and Macroscopic Efficiencies, mobilities, injection scheme, optimum pressure and time for injection.

Water injection below water table and in oil column is possible and efficiency of injection in water wet reservoir is considerably higher than oil wet reservoir.

From the microscopic point of view some of oil drops will be remained in large pores because of the interfacial tension between water and oil (water wet rocks) and if the reservoir is oil wet some of water drops will be trapped in larger pores.

6.3. Gas Injection

Gas injection is one of the most important methods in increasing oil recovery from a reservoir and is applied to move oil or maintain pressure in a reservoir. In any gas injection project there are some options between the type of gases and the periods of injections. Before the start of injection an estimation of number of barrels of oil per thousand of standard cubic feet of gas, injection costs, useful periods, physical and chemical characteristics and equipment costs should be prepared. There are two types of gas injection (based on gas composition): Hydrocarbon gases: enriched or lean and non-hydrocarbon gases like Nitrogen, Air or Flue gas.

7. Technical Gas Injection Evaluation

The scope of this section is to evaluate the impact in terms of surface facilities, reserves and recovery factor of using different fluid composition for the studied field gas injection:

- Rich gas, corresponding to the associated separator gas to be injected.
- Lean gas-case 1, corresponding to C1+C2
- Lean gas-case 2, corresponding to C1+C2+C3+C4

The reservoir is characterized by largely under saturated oil, with a bubble point pressure of about 5500 psi and a reservoir initial pressure of about 9500 psi. With the above mentioned reservoir characteristics, a secondary recovery by miscible gas injection is very beneficial to keep the original reservoir energy and to consequently maximize the production plateau duration and final hydrocarbon recovery.

The “Rich gas” injection compositional model run assumes that the rich gas injected stream comes from the sum of the gas streams from the first, second and third stage separators.

The “Lean gas” injection compositional model run assumes that the injected gas stream comes from the associated separator gas to be injected after condensate removal.

The gas injection composition is affecting the Minimum Miscibility Pressure (MMP) that represents the threshold pressure to which miscibility is achieved. Lower is the MMP greater are the benefit of miscible gas injection.

The (MMP) Minimum Miscibility Pressure in case of Lean Gas Injection will be about 400 psi higher than the MMP in case of Rich Gas injection, which will lead to accelerate the peak gas production and the gas breakthrough in some wells. Examination of the output from the compositional model giving separator gas composition was used to determine the composition of the injected lean gas, and the volume lost for re-injection (in addition to the 10% assumed for fuel gas), by recovery of the higher ends.

The results of the PVT analysis carried out on the fluid samples from appraisal wells have substantially confirmed the thermodynamic characteristic of the reservoir fluids and their miscibility behaviour with the injection gas. The geochemical analysis performed on appraisal wells samples are in perfect agreement with each other and with assumptions. The (MMP) Minimum Miscibility Pressure in case of Lean Gas Injection has been calculated to be about 400 psi higher than the MMP in case of Rich Gas injection. A comparison between the profiles for rich gas injection case compared to the lean gas injection cases are illustrated in Table 1 and figure 1.

Table. 1: comparison between gas injection cases.

Case	Plateau duration years	Reserves at 40 years Bstb	Recovery Factor %
Rich gas injection	17.1	1.72	35.2
Lean gas-case 1	14	1.61	32.5
Lean gas-case 2	16.1	1.66	33.9

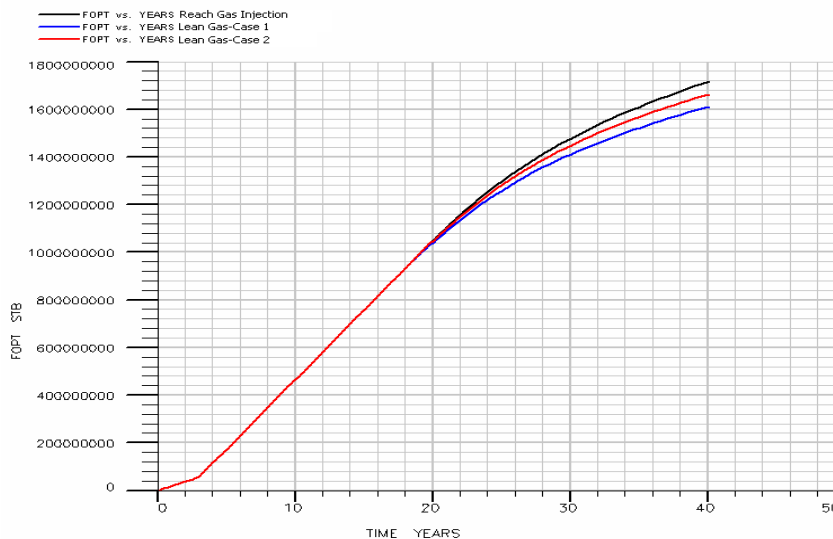


Fig. 1: Lean gas injection-impact on total oil production.

8. Results

Natural depletion model results

The “Natural depletion” compositional model run assumes that no pressure maintenance is performed in the reservoir development. The main results of the “Natural depletion” compositional model are as follows:

Reserves @ 40 years, Recovery Factor and Plateau period

- The ultimate oil reserves are equal to 1.06 BStb.
- The associated oil recovery factor is 21.7 %.
- The expected duration of the plateau production rate is 8.1 years.

Rich gas injection model results

The main results of the compositional model “Rich gas” injection case are as follows:

Reserves @ 40 years, Recovery Factor and Plateau period

- The ultimate oil reserves are equal to 1.72 BStb.
- The associated oil recovery factor is 35.2 %.
- The expected duration of the plateau production rate is 17.1 years.

Lean gas injection model results

Assuming that the associated separator gas after condensate removal, is injected, the main results of the May 2004 compositional “Lean gas” injection case are as follows:

Reserves @ 40 years, Recovery Factor and Plateau period

- The ultimate oil reserves are equal to 1.66 BStb (reduction of 0.06 BStb).
- The associated oil recovery factor is 33.9 %.
- The expected duration of the plateau production rate is 16.1 years.

9. Conclusions

The secondary recovery by miscible “Rich Gas” injection is very beneficial allowing a 0.66 BStb recovery increase and 9 years longer plateau compared to the “Natural Depletion” scenario. Assuming Condensate is recovered from the separator gas before injection, the condensate yield, which will drop out of the associated gas, was calculated to be about 12 Stb/MMScf corresponding to a peak daily condensate production of approximately 2900 Stb. However, the “Lean Gas” injection after the condensate removal will imply the following disadvantages:

- Loss of more than 53 MMStb of Oil Reserves.
- 1.3% Field Recovery Factor reduction.
- 1-year shorter plateau.
- Increased risk of Gas break through
- Approximately, 230 MMUSD additional facilities cost
- Increased operating cost to manage the new gas treatment and condensate recovery facilities.
- Increased environmental impact.

For the above-mentioned reasons, it is recommended to utilize the “Rich gas”, corresponding to the associated separator gas to implement the miscible gas injection and enhance the final oil recovery in formations.

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