EVALUATION OF WATER AND GAS INJECTION IN A CARBONATE RESERVOIR

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This paper was prepared for presentation at the International Symposium of the Society of Core Analysts held in Abu Dhabi, UAE, 5-9 October 2004

ABSTRACT
Most of the oil production in the Middle East comes from carbonate reservoirs, the majority of which are fractured. These reservoirs tend to produce at high rates in their early production period followed by low rates later on, leading to low overall recovery. The challenge is to manage the field and arrest the production decline for a long time.

A reservoir simulation study was performed on a fractured Middle Eastern carbonate field to determine the optimal production strategy. Two sector models from two parts of the field were constructed. Three possible scenarios – natural depletion, gas injection and water injection were compared. Results indicated that gas injection yields better recoveries than water injection and natural depletion, for both sector models. This is expected since the rock is intermediate to oil-wet, meaning that there was little recovery from imbibition in water flooding. The presence of connected fractures led to early breakthrough and low recoveries. The different physical mechanisms affecting oil recovery are discussed and recommendations are made for other fields with the same fracture properties and wettabilities.

INTRODUCTION
The challenge in secondary and tertiary recovery for carbonate reservoirs is that they are inherently heterogeneous. This heterogeneity caused by the depositional environment becomes more extreme through structural movements that create folds, fractures and faults during the initial burial or later regional uplift. The presence of these high permeability fractures has a major impact on the flow behaviour within the reservoir. This behaviour has to be understood carefully for the selection of the most suitable secondary recovery mechanism to increase oil production from such fields.

Another major factor controlling the distribution and flow of fluids in carbonate reservoirs is wettability. It has a significant importance in reservoir development and management because of its strong influence on capillary pressure and relative permeability. A wettability evaluation by Treiber et al. [7] on 50 carbonate rocks showed that 84% of carbonate reservoirs were oil-wet with contact angles between 105^o and 180^o.

Chilingar et al. [1] also performed contact angle measurements on 161 carbonate samples and concluded that 15% of the rocks were strongly oil-wet and 65% were oil-wet.

In this project a partially fractured carbonate reservoir in the Middle East was studied. Two sector models, fractured and non-fractured, representing two parts of the reservoir were constructed. These results could also be used to compare the impact of fractures, with the same fluid properties, relative permeability tables and PVT data. The aims of this project were

- To evaluate the impact of fractures on the recovery from the field;
- To determine the optimal secondary recovery technique for this reservoir.

MODEL CONSTRUCTION

Both sector models represented the whole width of the field with dip closure to OWCs on the NE and SW flanks. Each model contained about 50,000 cells representing somewhere between a fifth and a quarter of the overall field STOIIP. A separate geological model supplied the reservoir description data. A dual porosity/permeability representation was used in the fractured sector model. Table 1 shows the differences and similarities of both sector models.

Table 1. The major differences and similarities between two sector models.
This allows comparing the results of a different rock type, but with the same fluid PVT data.

Key Input Parameter	Comparison	Sector 1, Fractured	Sector 2, Non-fractured
Model Dimensions	Different	55×35×30=57750 cells	43×33×30 = 42570 cells
Matrix Porosity		7 – 15% in zone C	14 – 17% in zone C
Fracture Porosity		= Matrix	N/A
Matrix Permeability (K_h)		4 – 23mD in zone E1	15–124mD in zone C2
Fracture Permeability (K_h)		7mD – 4D in zone E1	N/A
Layer thicknesses		30 – 70ft zone E1	55 – 70ft zone E1
Dip Angle & Derivatives		Steeply folded over crest 20-25° dip	Shallower crestal folding 10° dip
Oil-Water Contact		12,765ft zone E	12,650ft zone E
Depths to Top		Determined by structural relief	
NTG Thickness Ratio		Average about 0.7 in both Sectors	
Well-bore Hydraulics		Four tables based on depths & tubing OD	
Fluid PVT	Same	Different between major layers, no aerial variation	
Relative Permeabilities		Different in some layers	
Permeability Ratio (K_v/K_h)		No strong G & G evidence for variations	

A primary recovery development option, using interventions on existing wells, additional infill wells and artificial lift, were used as the basis for formulating secondary recovery schemes with gas injection and water flooding. Separate development options incorporating either crestal gas injection or pattern flooding with gas using five-spots were simulated and compared. Development options using flank water injection with and without moving line drive were also simulated and compared. Operational events, such as well re-completions and well conversions, were scheduled in the simulations to provide more realism. All the simulations were run over a thirty-year period from year 2000 to 2030, unless for primary depletion case in non-fractured section, where simulations were run for 40 years.

SIMULATION RESULTS

Primary Depletion

In this option, only the natural energy of the reservoir is used as the drive mechanism to continue the field development. This is a combination of pressure depletion, oil expansion, rock compression and some flank aquifer influx. These mechanisms act together in both models to varying degrees. These simulations showed that oil recovery on a whole field basis would be about 6.5% STOIIP for Sector 1 (fractured) and 9% for Sector 2 (non-fractured) after the historical and more than 30 years of new production.

Figure 1 shows the production profiles that demonstrate an increase in oil production for both sector models. This is due to infill drilling. Initial oil production in the fractured sector is a slightly greater than in the non-fractured region, because still oil is more

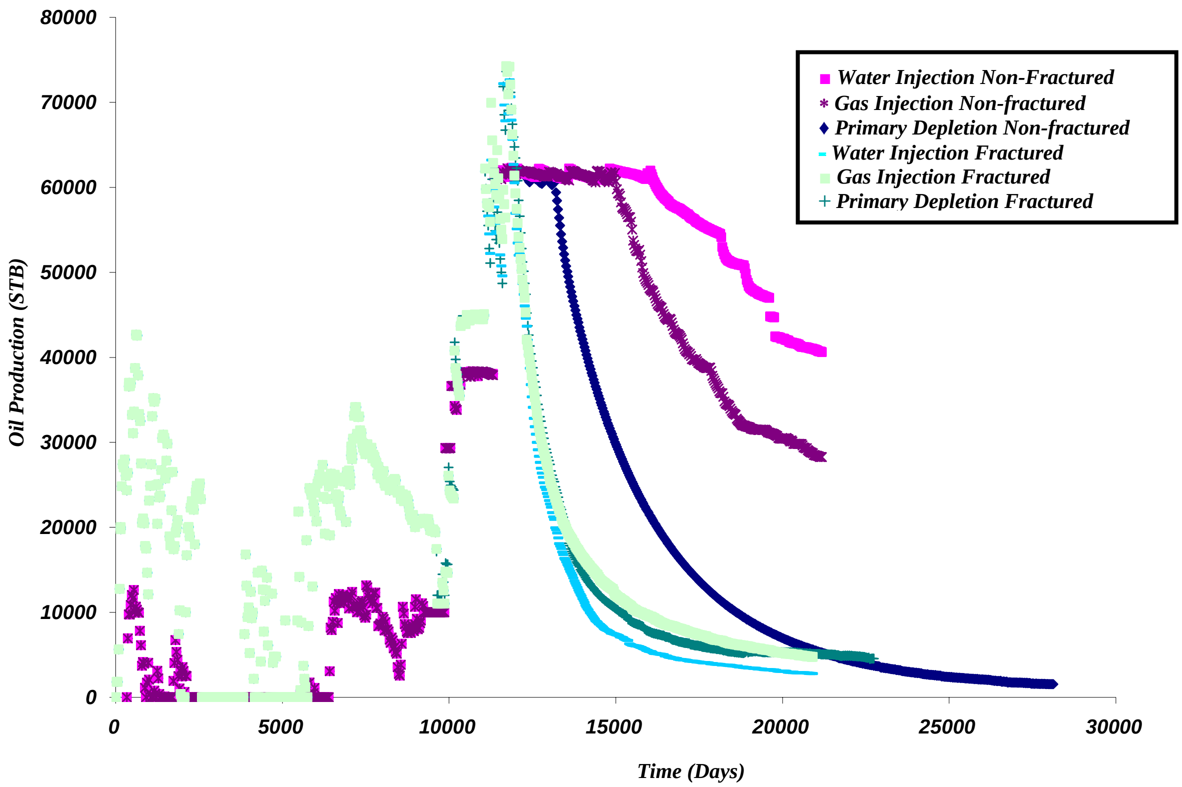

Figure 1: Oil production profiles for all scenarios

Oil production is increased in both fractured and non-fractured sector models due to infill drilling. Gas injection shows better recovery than water injection.

readily drained and displaced by aquifer water from the fractures than it is from the rock matrix. More water production in the fractured model is apparent, because of early breakthrough occurring in the high permeability fractures.

Water Injection

For this option, down dip water injection provided a stable displacement process because of the high angles of dip (≈20^o) prevalent in the field. Water injection is seen as complimentary to the well re-completions, artificial lift and infill wells of the primary program. The simulations showed that the cumulative oil recovered from the field would be less than 6% STOIIP for the fractured sector model, and about 16% for the non-fractured one. Water injection in the fractured model resulted in slightly less recovery than primary production alone. This was expected, because of the intermediate to oil-wet wettability in this reservoir. Water does not enter the matrix by imbibition and only displaces oil from the fractures, resulting in an unfavourable recovery.

Gas Injection

For this option crestal gas injection (CGI) is performed in addition to the well re-completions, artificial lift and infill wells of the primary development option. With the high angles of dip CGI should be a favourable displacement process, displacing oil to down-dip producers, creating the gas cap in the topside of the reservoir. However, along the strike of the field (NW-SE) there is little or no dip and gas will move readily in this direction. The simulations showed that oil recovery on a field basis, including previously produced oil, is likely to be about 6.5% and 14% STOIIP from the fractured and non-fractured models respectively. The recovery from the fractured sector is little better than primary production, indicating that gravity drainage is not an effective displacement mechanism in this case. The decrease in the recovery factor in the non-fractured sector for the gas injection in comparison with water injection is simply because less gas is injected in comparison to water. As a function of pore volume of fluid injected gas injection shows better recoveries. In this case, due to the wettability of the field, gas injection is favoured over water injection for both fractured and non-fractured portions of the field.

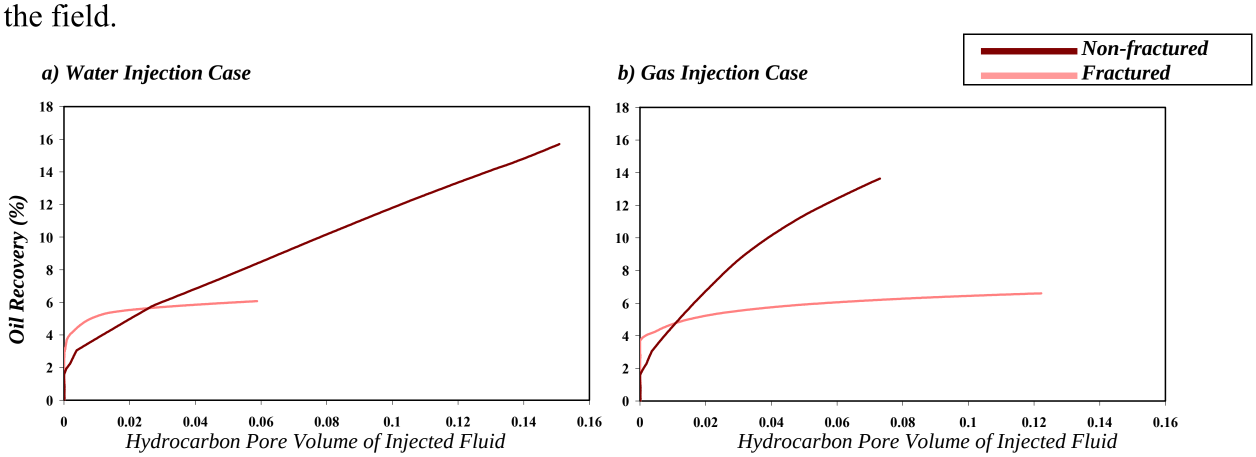

Figure 2: Water and Gas injection in the fractured and non-fractured sector models

In both cases, the fractured sector model showed an early high production but less ultimate recovery.

DISCUSSION

Suitable Secondary Recovery Technique

Wettability and presence of fractures are major factors controlling the distribution and flow of fluids in a reservoir. Wettability has a strong influence on capillary pressure and relative permeability. In this study, the reservoir was assumed to be intermediate to oil-wet. Hence during water injection, water imbibition into the matrix was low. However, during gas injection, the injected gas displaced more oil than waterflooding, as shown in Figure 3a, although the overall recovery remained low due to presence of fractures.

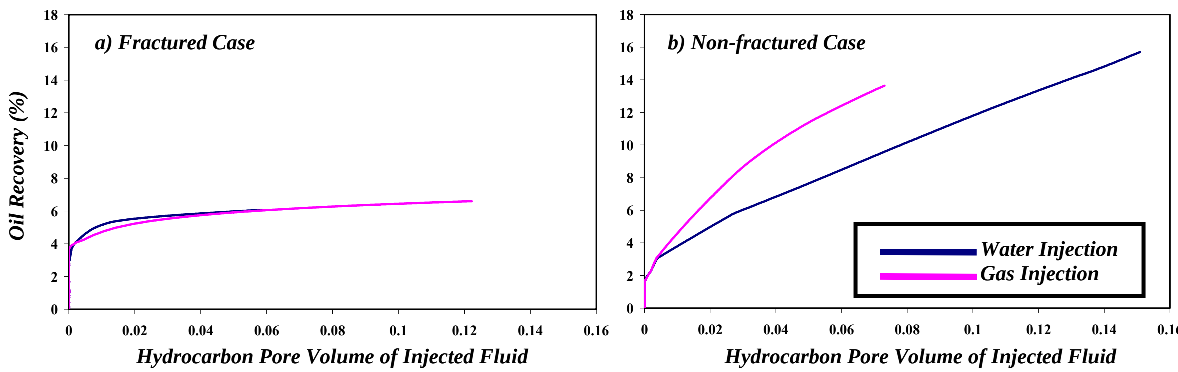

Figure 3: Fractured and Non-fractured sector models with water and gas injection

In both cases, gas injection yields better recoveries than water injection because of rock wettability

However, in the non-fractured sector model, both schemes of secondary recovery showed high recoveries with respect to natural depletion. Figure 3b shows the oil recovery for both cases versus hydrocarbon pore volume of fluid injected. This graph shows that gas injection yielded higher oil recoveries than water injection. Ultimately, gas injection appears to be the preferred secondary recovery mechanism for this field.

The Impact of Fractures on Recovery

Fractures play an important role in oil recovery especially in low permeability reservoirs by creating a high permeability conduit from the matrix towards the wells. Thus, high permeability fractures are responsible for high production rates. Unfortunately they create some disadvantages; first, once a fracture is depleted of oil there is a substantial drop in oil production. Second, during injection process fractures accelerate the flow of the injected fluid towards the production wells. Figure 2 shows a comparison of gas injection in both sector models.

CONCLUSIONS

The simulations of this Middle East carbonate reservoir have provided insights into how this field and similar ones might be further developed using secondary recovery techniques.

1- At early times, fractures increased the oil recovery compared with non-fractured case, since they allowed higher production rates.

2- Water injection did not improve recovery over primary production in the fractured regions of the field. This appears to be due to low water imbibition into the matrix due to its intermediate to oil-wet wettability.
3- Gas injection seems to be the preferred technique for secondary recovery, since there was additional displacement of oil by gas in the fractured regions.

ACKNOWLEDGEMENTS

The authors would like to thank BP plc, in Sunbury for providing the dataset and their financial support in carrying this study.

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* Due to the BP Company confidentiality the name of field was withheld.