032 NUMERICAL SIMULATION OF CO₂ INJECTION IN A HEAVY OIL FRACTURED RESERVOIR — CASE STUDY OF BATI-RAMAN FIELD, TURKEY

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Introduction

Immiscible CO₂ injection has been successfully applied since 1986 by the Turkish Petroleum Corporation (TPAO) in the fissured heavy-oil field of Bati Raman. Because of the low reservoir energy and of the unfavorable oil properties, the expected ultimate recovery through primary production was less than 2 % of the initial 1.85 billion STB oil in place and the field oil rate had declined to 1500 STB/D by 1985 after 25 years of production. CO₂ injection allowed to establish a plateau oil production rate of 12000 STB/D from 1990 and to double the cumulative oil production within 10 years. An integrated reservoir study including a detailed numerical simulation work has been performed to provide a quantitative understanding of the oil recovery mechanisms and of the sweep efficiency by the gas.

Reservoir characteristics. The Bati Raman field is a 10.5 x 2.5 miles east-west elongated anticline in southeast Turkey. It produces from Cretaceous carbonates of reefal origin : the Garzan limestones extending over 10700 acres with a gross thickness of 210 ft at an average depth of 4300 ft. The reservoir rock is a heterogeneous fissured vuggy limestone. Matrix porosity varies from 10 to 25 % and permeability from 1 to 50 md with significant areal and vertical variations. The estimated secondary porosity varies from 0.5 to 2 % and permeability from 400 to 2000 md. The secondary porosity and permeability system is believed to be better developed in the western and central parts of the field. From the core description, the fissure density in those areas was estimated to be equivalent to cubic matrix block sizes of 3 to 30 ft.

Fluid properties. The heavy oil is undersaturated with a very low solution gas-oil ratio (GOR) between 10 and 46 scf/bbl and an average saturation pressure at 160 psi. The API gravity varies from 9 to 15 °API with the lowest values towards the flanks of the structure. At initial reservoir conditions (1800 psi, 150 °F), the oil viscosity varies between 500 and 1500 cp.

Past production. Production started in 1961 (Fig. 1) but the intensive drilling of the field occurred between 1968 and 1970. Before 1986, the main recovery mechanisms were rock and monophasic fluid expansion, complemented by a weak aquifer influence in the northern flank of the structure. Due to the low oil compressibility, a significant pressure decline was experienced and production levels decreased from 9000 STB/D in 1969 to 1500 STB/D in 1985. A limited water injection was implemented from 1971 to 1979 in the most depleted part of the central area. The analysis of the injection performance indicates a limited spontaneous imbibition of the water in the matrix allowing to recover a few percent of the matrix oil. Combined to emulsion problems in the water producing wells, the mitigated results led to abandoning the water injection.

Gas injection was initiated in 1986. The gas source is the Dodan field which produces gas with an average 88 % CO₂ content. A cyclic injection-production process was initially tested. The rapid spreading of the gas in the fissure network was found to prevent a sufficient pressure increase in the vicinity of the injecting wells for "huff and puff" application. The initial process was changed into a continuous gasdrive process starting with a repeated five spot pattern including 17 injectors in three rows with an average 30 acres spacing in the western area of the field. Despite a rapid breakthrough of

the gas into the producing wells, the injection proved successful. GOR's rapidly stabilized at about 2000 scf/bbl and a steady increase of the average oil rate per well was observed, in relation to a general pressure increase over the application area and to improved oil characteristics.

The gas injection area was progressively extended in a less regular pattern towards the central and eastern parts of the field. The number of operating injectors peaked at 60 with an average ratio of 3.5 producers per injector. The oil rate rose to an average 12000 STB/D in 1990 and no significant decline was observed at end of 1995. The gas injection rate during that period averaged 35 million scf/D.

Analysis of the injection performance

Immiscible CO₂ injection. Due to the high molecular weight of Bati Raman oil and to the low reservoir pressure, CO₂ injection acts as an immiscible process, taking advantage of the oil-swelling and viscosity reduction effect of CO₂ going into solution in the oil. At 1800 psi, the solubility of CO₂ in the Bati Raman oil amounts to 450 scf/bbl, increasing the oil formation volume from initial 1.04 to 1.20 RB/STB. The viscosity of the saturated oil decreases drastically from an average 1000 cp to less than 100 cp.

At field scale, the success of the injection process is directly related to the amount of oil contacted by the injection gas. The percentage of backproduced gas during the first seven years of injection varied from 40 % (during first year) to 80 % in the western area, and from 16 to 60 % in the central area. A material balance analysis performed in the application area during this period demonstrates that most of the gas remaining in the reservoir (difference between the injected and produced gas over the application area) must be in solution in the reservoir oil. Furthermore, considering the gas solubility at the average reservoir pressure and the volume of gas in solution, it can be found that 10 to 30 % of the reservoir oil has been contacted by gas. The understanding of such a high efficiency despite a very adverse mobility ratio has to be related to the fissured nature of the reservoir.

Fracture/matrix system. The existence of a fracture/matrix system over the major part of the field is clear from the core examination and from the high values of effective permeabilities in the wells as compared to matrix permeabilities measured on core plugs. The effectiveness of a dual-porosity behaviour was confirmed by the results of the first injection tests. In most injection wells, a limited pressure increase and a rapid spreading of the gas towards the surrounding wells were observed, indicating that the gas moved rapidly through the fissure network. Only a few wells in the westernmost area showed a matrixal behaviour with a rapid pressure increase as the gas dissolving in oil is confined near the wellbore by the low mobility of the oil distant from the wellbore. Numerical simulations confirmed the interpretation of these two different behaviours.

Diffusion process. In the dual porosity system, the success of the injection process relies on the diffusion of gas in the fissures into oil in the matrix. The gas rapidly moves through the fissures, saturating the fissure oil in the swept areas. Due to the very adverse mobility ratio, the amount of free gas in the fissures remains very low. But the difference in concentration of dissolved gas between the oil in fissures and matrix allows for a significant diffusion of gas inside the oil phase. As the gas concentration increases, the matrix oil swells and is expelled into the fissure network.

The speed of the diffusion process is directly related to the density of the fissure network. The observed performances of the gas injection in the field reflect this interaction. In the central area where the fissure network is assumed to be denser, the GOR in the producers increases progressively, reaching an average 2000 stb/bbl after three years. The percent of backproduced gas does not exceed 60 %. This behaviour indicates a relatively high diffusion rate which delays the movement of the gas in the fracture network. In the western area where the fissure density is lower, the GOR increases rapidly after the breakthrough and stabilizes at 2000 to 4000 scf/bbl, and the percent of backproduced gas reaches 80 %. This indicates that a fair amount of invasion of the fissure network by the gas is required to yield a significant contribution of the matrix to oil production because of a lower diffusion rate.

Numerical simulation

The numerical simulations were performed using the simulator ATHOS developed by IFP (French Petroleum Institute) and Beicip-Franlab. The dual porosity formulation with matrix-fissure diffusion was used. The fluid properties were represented by a two-component PVT set reproducing the mixture of Bati Raman oil and Dodan gas and accounting for the solubility of the gas in the formation water. Because of the very low initial gas content of the oil, the associated gas was not represented as a separate component.

The model was validated at three different scales to ensure the reliability of the calculations : simulation of laboratory experiments, fine grid simulation of injection patterns, full field simulations.

Simulation of diffusion experiments. Experimental studies of the gas diffusion in cores saturated with oil and connate water were performed by IFP on different length core samples to investigate the relationship between the transfer coefficient and the matrix block size. In these experiments, the cores are put in contact with a given volume of gas at both ends under a 2175 psi pressure. The evolution of the pressure drop while gas diffuses into oil is measured.

These experiments were simulated using a single cell dual-porosity model where the core sample was represented by one matrix block and the gas cells at both ends were represented by the fissures. The model formulation to represent the diffusion from the gas bearing fissure into the oil bearing matrix is illustrated in Fig. 2. It is assumed that a thermodynamic equilibrium exists at the face of the block between the matrix oil and the fissure gas, so that the gas diffusion occurs between the saturated oil at the face of the block and the undersaturated oil inside the block.

The value of the diffusion coefficient was adjusted to reproduce the experimental pressure measurements. The model yields an excellent match of the experimental pressures (Fig. 3) with values of the diffusion coefficient in close agreement with the calculated values derived from the experiments. The coefficient of $6 \times 10^{-5} \text{ cm}^2/\text{s}$ derived from the experiment performed with the maximum core length of 1.3 ft was later successfully used for all the field scale simulations.

Simulation of injection patterns. Finely gridded sector models representing symmetry elements of regular injection patterns in two representative zones of the western and central areas of the field have been simulated. Each model consisted in one quadrant including a corner injection well and a diagonal producer with a large external area accounting for the effect of unconfined injection. The average injection and production per well in each zone was simulated and the sensitivity of the calculated production GOR to the reservoir properties was investigated.

From the analysis of the model response, it was found that the incremental production probably results from the combination of diffusion and gravity mechanisms. The diffusion process is mainly responsible for the early oil flow related to the swelling of the matrix oil during gas dissolution. It governs the initial GOR profile. The efficiency of the diffusion process depends on the matrix block size. The gravity drainage process allows for the entry of free gas into the matrix blocks where the oil has been saturated through diffusion. It contributes to the later oil recovery and governs the late GOR profile. The efficiency of the gravity drainage process depends on the matrix block size and on the vertical permeability of the matrix.

The sensitivities to the matrix block size proved quite consistent with the understanding of the areal and vertical variations in the fissure network. In particular, the already described differences between the observed behaviours of the western and eastern areas were matched in accordance with the typical features of each area. The model adjustment yielded realistic block sizes varying between 7 to 15 ft in the most fractured units and 15 to 30 ft in the less fractured ones.

Due to the strongly adverse mobility ratio, the time between the start of injection and the gas breakthrough in the producers is short (3 to 6 months with an average 1000 to 1300 feet distance between wells) and poorly sensitive to the diffusion process. The free gas saturation in the fissures after breakthrough remains very low with an approximative average of 0.3 %. Considering the adverse mobility ratio, the areal and vertical efficiency of the displacement appears to be quite good and indicates very homogeneous properties of the fissure network.

Gridding effects. Considering the field dimensions and the number of wells, a minimum cell dimension of 328 x 328 ft (100 x 100 meters) was selected for the full field model (Fig. 4), yielding in average 3 to 4 cells between adjacent producing and injecting wells. Five layers were represented. Significant grid effects, and particularly orientation effects, were expected while simulating gas injection in such a grid. Comparisons between the fine grid sector models and equivalent models honouring the field model gridding showed that the use of a nine-point scheme calculation was sufficient to correct most gridding effects without using any pseudo-functions.

This statement calls for some explanations. It should first be noted that very short breakthrough times are simulated with respect to the total duration of the simulated injection, and that the main production process occurs when the free gas saturation in the fissures is established. In addition, two antagonist effects of the grid coarsening may have balanced one another. Large cell sizes in horizontal direction contribute to accelerate the calculated gas encroachment, while thick layers do not reproduce the effect of segregation and heterogeneities and contribute to decrease the calculated speed of displacement.

Full field simulation. The field modelling was based on a 3D geological model separating six facies on the basis of both matrix and fissure properties. The two sets of properties are in fact closely related as the rock is found to become more strongly fissured when the matrix becomes tighter. The matrix permeabilities and matrix block sizes were distributed according to this facies distribution, initially assuming a single average value for each facies. This description was slightly improved during the history match to account for an apparent improvement of the matrix properties at the top of the reservoir. The selected average values per facies were based on the results of the sector model simulations. Uniform fissure properties were assumed over the main production zone. The flank permeabilities and the aquifer size and properties were adjusted during the preliminary history matching of the primary production period prior to gas injection.

It is remarkable that a satisfactory history match of the gas production was obtained for most wells using this rather simple description with very few local adjustments. This has to be related to the seemingly very homogeneous fissure properties.

Full field predictions were simulated to validate the planned drilling and production policy over the next ten years. The simulations demonstrated the benefit of monitoring the GOR variations to control gas cycling. This led to the recommendation that the injection should be rapidly decreased in the zones where a rapid increase in GOR is observed, and the available injection gas should be redistributed to other zones to keep a balanced gas cycling over the reservoir. Few development possibilities remain in the field, but the present oil rate can be maintained with a very limited decline for at least 10 years. An overall ultimate recovery factor of 8 to 9 % is expected according to the predicted performances in the western part of the field where the production is most advanced.

Conclusions

A complex CO₂ immiscible injection process in a fissured reservoir was successfully simulated using a dual porosity model with fracture-matrix diffusion. The model was validated by the simulation of core diffusion experiments and of finely gridded sector models before it was used for the full field simulation of a large reservoir with 280 wells. The correction of grid effects in a highly unstable flood by the use of nine point calculation permitted to limit the cell number to an acceptable size for running on a workstation. The simulations helped to understand the respective contributions of diffusion and gravity drainage to the oil recovery. A consistent description relying on the distribution of matrix block size according to geological facies allowed to reproduce the observed variations of injection performance over the field. The history matched full field model provides a valuable reservoir management tool for the estimation and optimization of the future field performance.

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Fig. 1 - History Match of the Field Production Profile

Fig. 2 - Diffusion in an Oil Saturated Matrix Block in Contact with Gas Saturated Fissures

Fig. 3 - Numerical Simulation of the Diffusion Laboratory Tests

Fig. 4 - Full Field Model Gridding