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Bati Raman Field Immiscible CO_2 Application: Status Quo and Future Plans

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Abstract

The Bati Raman field is the largest oil field in Turkey and contains some 1.85 billion barrels of oil initially in place. The oil is heavy (12 ^{o}API) with high viscosity and low solution gas. Primary recovery has been inefficient, less than 2% of OOIP.

Over the period of primary recovery, from 1961 to 1986, the reservoir underwent extensive pressure depletion from 1,800 psig to as low as 400 psig in some regions, with a related production decline from a peak of approximately 9,000 Bbls/day to 1600 Bbls/day.

In March 1986, a CO_2 injection pilot scheme in a 1200 acre area containing 33 wells was initiated in the west portion of the field. The gas injection was initially cyclic; “huff and puff” method was applied. Later, in 1988, the gas injection scheme was converted to a CO_2 flood process. Later, the process was widespread to cover the whole field.

A peak daily production rate 13000 STB/d was achieved in 1993 in comparison to what would have been less than 1600 STB/d without CO_2 application. However, since 1995, the field has undergone a progressive production decline to recent levels at approximately 5,500 Bbls/day. Polymer gel treatments were carried out to increase the CO_2 sweep efficiency and arrest the decline. Multilateral and horizontal well technology was also applied on pilot scale to reach the bypassed oil. WAG is applied widespread now. Current production is 7000 Bbls/day.

This paper documents TPAO’s 25$^+$ years of experience on the design and operation of full field immiscible CO_2 injection recovery project conducted in the B.Raman heavy oil field, in Turkey. The objective is to give an up-to-date status of the performance of the application; reservoir/field problems that TPAO had, unexpected occurrences and results and just a general idea of how successful the project has been.

Introduction

The Bati Raman field, which is the known highest oil accumulation in Turkey, contains very viscous and low gravity oil in a very challenging geological environment. Due to the fact that the recovery factor by primary recovery was limited, several EOR techniques had been proposed and tested in pilot level in the 70s and 80s. Based on the success in the lab tests and vast amount of CO_2 available in a neighboring field which is just 55 miles away from the Bati Raman field, field scale huff-and puff injection was started in the early 80s. Due to the early breakthrough of CO_2 in offset wells in a short period of time, the project was converted to field scale random pattern continuous injection. Over more than 20 years of injection, the recovery peaked at ~13,000 bbls and began to decline reaching today’s ~7,000 bbl value.

In the case of Bati Raman, at this mature state of the process, the injected agent is increasingly bypassing the remaining oil and production is curtailed by excessive high gas oil ratios (GOR). The naturally fractured characteristics of the reservoir rock has been a challenge for establishing a successful 3D conformance from the beginning and its impact is even more pronounced in the later stages of the process. Because of that reason, the subject field requires modification on the reservoir management scheme to improve recovery factors as well as improving productivity of the current wells.

BATI RAMAN FIELD

Bati Raman was discovered in 1961 in Southeastern Turkey with the completion of BR-1 (Fig-l). The producing formation is the Garzan Limestone, a very heterogeneous carbonate of Cretaceous age. The reservoir fluid is a very heavy crude oil, having an API gravity ranging from 9.7 to 15.1 and a viscosity ranging from 450 to 1000 centipoises at reservoir conditions.

The structural trap is a long; partly asymmetric anticline oriented in the east-west direction which measures about 17 km. long and 2 to 4 km. wide. It is limited by an oil/water contact at 600 meters subsea in the north and west, by a fault system in the southwest and south, and by a permeability barrier in the southern and southeastern part of the field. Formation has a gross thickness of 210 ft (64m). The oil column from the top of structure to the OWC is about 690 ft.

The Garzan limestone has a reefal origin and exhibits rather pronounced heterogeneity both areally and vertically. The studies point out the evidence of several depositional facies in Garzan limestone. Reservoir average porosity is 18% and mainly vugular and fissured in type. It has a clean porous matrix, but the permeability is low. The typical matrix permeability by core analysis is 10 to 100 md; however, well tests show effective permeabilities in the range of 200 to 500 md, confirming the contribution of secondary porosity (fractures, vugs, and connecting cracks).

In the eastern half, the formation is chalky. Although some fissuration is observed, these are not believed to constitute an effective secondary porosity. By contrast, in the central and western part, a well developed system of secondary porosity and permeability is believed to exist. In these areas, a secondary vugular porosity interconnected by fissures appears to be superimposed over a low primary porosity matrix.

The main production mechanism is rock and fluid expansion. There is a very weak aquifer influence which is barely evident at some of the central northern flank wells, only. The original reservoir pressure is 1800 psi, the solution GOR is 18 SCF/STB resulting in a low bubble point pressure, just above 160 psig at an average depth of 4300 ft. Taking into consideration the unfavorable properties of the oil (such as low gravity, low solution gas and high viscosity), low reservoir energy and the type of the driving mechanism, primary recovery prospects are naturally very low. It is estimated that, ultimately, 1.5% of the 1.85 billion barrels of initial oil in place can be produced from Bati Raman field through primary production and that is nearly the case.

Field Development, Early Studies and Tests on Secondary Production and EOR Techniques

The field, at the beginning, was developed on 62-acre spacing. The field reached its peak production rate, about 9000 B/D, in 1969 after which production decline began. Initial well producing rates ranged up to 400 B/D.

The trend in primary recovery and the rapid decline in reservoir pressure suggested the need for a suitable EOR method to produce a significant fraction of the vast reserve. Numerous EOR techniques have been evaluated at various times through field history. A series of laboratory studies and comparative engineering analysis(1) as well as some field tests to enhance recovery, including water injection, steam cycling, steam-drive, and air injection (for in-situ combustion) were carried out at the early life of the field. Several techniques such as polymer and surfactant flooding were ruled out because the chemicals available at that time would have degraded rapidly at the high reservoir temperatures and high salinity characteristic of the formation water. Of these, only the five-spot waterflood project proved to be conclusive. About 3.2 million bbl of water were injected in the central area of the field between 1971 and 1978. This process resulted in a marked increase in oil production over the decline trend (Fig-2) from wells on the entire central area, but indicated that only a moderately increased recovery up to 5 % of the oil in place could be achieved.

But, as it can be predicted easily, water injection in heavy oil reservoir generates severe troubles causing the operators a lot of tiring efforts. Accomplishing this range of recovery with water injection, alone, has a limited chance in terms of applicability and endurance. BR-17 which is located at the center of the five-spot waterflood pattern was temporarily abandoned for a long time subsequent to the breakthrough due to waterflood application. Despite of the constructive contribution of CO_2 injection at a later phase, the well could hardly be put back on production.

As a part of the EOR analysis of the B.Raman field, the use of steam displacement and in situ combustion have been examined as well. Although the theoretical recovery data were encouraging, in situ combustion has not been recommended primarily because of high risks, uncertain technology and operational problems so it was eliminated. Both CO_2 and steam applications were found favorable. However, immiscible CO_2 application appeared more feasible because of the nearby Dodan CO_2 gas reserve and the high initial investment cost of steam injection.

Dodan Gas Field

Dodan gas field is located in the South-East part of Turkey, approximately 55 miles far from the Bati Raman Oil Field. The Dodan field consists of a number of separate producible gas bearing zones, each being mainly limestones, at depths from 2800 ft. to 7400 ft. Gas compositions vary from zone to zone or well to well. Thus various mixtures of gases are produced from time to time from the field. With the deve1opment wells drilled late in 1979 and 1980, a total gas reserve of 250 BSCF was estimated to exist in the zones with certain proportions.

The compositions of the gas contained in each formation are almost alike, predominantly consisting of carbondioxide. The gas contains H_2S in the ranges of 3000-4000 ppm. Reservoir pressure varies from 1650 psig to 2400 psig with depth. Wellhead static pressures, however, are almost the same, about 1000—1100 psig.

Carbon dioxide (CO_2) Stimulation

A CO_2 flood EOR may be characterized as the injection of carbon dioxide or a combination of water and carbon dioxide (WAG) into oil bearing zones in order to extract oil by lowering its flow through resistance (viscosity).

The displacement of oil by gas can be classified as immiscible and miscible or multicontact miscible processes, depending on the properties of the gas injected and the reservoir fluids at reservoir conditions. The pressure required for miscible or multicontact miscible displacement depends on the reservoir temperature and oil composition. Immiscible displacement occurs at pressures below minimum miscibility pressure (MMP), in which there is less interchange of components or mixing zones between the injected gas and the reservoir fluid.

Conventional use of CO_2 for improving oil recovery has been mostly confined to miscible applications. However, in B.Raman miscible drive was ruled out from the beginning since reservoir pressure is well below the minimum miscibility pressure and is not a factor in increased oil recovery.

For immiscible CO_2 application and subsequent waterflooding, the main parameters that affect the ultimate recovery significantly are fracture spacing, critical gas saturation, and diffusion rate. Injected gas dissolves in the oil to swell it, but at the same time diffuses from fracture to matrix.

CO_2 dissolves more readily in water than hydrocarbon gases. Its solubility, however, is a function of pressure, temperature and the ion content of the brine. It is also a particular interest to investigate whether the injected CO_2 mixing with connate or injected water can enhance matrix permeability. CO_2 and H_2O may simply increase the fracture conductivity which would be detrimental to the efficiency of the recovery process.

Field Test

In spite of uncertainties involved, the results of various studies showed overwhelming evidence that a substantial quantity of oil could be recovered by cyclic Dodan gas injection possibly followed by a waterflood. The best way to see this is to test it in the field. It was decided to test oil recovery by cyclic Dodan gas injection with a pilot application (in early 1980), and so that depending on early performance of the reservoir, corrective measures could be taken. The general area chosen for this demonstration project was the western part of the field, encompassing about 1200 acres with 33 adjacent wells drilled in a five spot pattern. The location map of pilot area is shown in Figure 3.

SURFACE FACILITIES

Having decided on immiscible CO_2 injection, TPAO started to prepare surface and subsurface facilities. Surface facilities for demonstration project include; Dodan field gas gathering system, Dodan gas processing and compression facilities, pipeline from Dodan to Bati Raman, Bati Raman injection and production piping network, two separator stations each consisting of one production and two test separators. Subsurface facilities include the preparation of 12 CO_2 production wells in Dodan field and 33 injection-production wells in Bati Raman field pilot test area.

Dodan Facilities

The Dodan facilities was designed to produce the equivalent of 60 MMSCFD of CO_2 rich reservoir fluid from the wells, to remove the hydrogen sulfide and water, and deliver about 55 MMSCFD of dry, H_2S free gas to the 10" Bati Raman pipeline.

Insulated, fiber-glass gathering lines were laid to transport the reservoir fluid from the wellheads to a central processing area. The production includes free water, CO_2 and other hydrocarbon gases with some other impurities. The gas is delivered to a Selexol plant for removal of H_2S. The gas from the Selexol plant is dried in a threethylene glycol system to 10 lb water/MMSCF to prevent water condensation in the pipeline at operating temperatures as low as -18°C (0°F). The gas containing less than 50 ppm H_2S by volume is then compressed up to the pipeline operating pressure.

Bati Raman Facilities

Much of the existing equipment at Bati Raman has been incorporated into the design to minimize capital cost while providing operational flexibility consistent with the needs of the project. The Western Test Area of Bati Raman was designed for cyclic CO_2 injection and production of 33 demonstration wells using existing Transfer Pump Stations 3TP1 and 3TP2 as the centers for operations.

The 3TP1 and 3TP2 pump stations include facilities to evaluate individual well performance, remove produced water and gas, and deliver the oil to AP1 main pump station for additional dehydration and desalting. After the decision of extending the CO_2 injection to the whole field in 1989, a 20 MMSCFD capacity recycle system was established in 3TP2 to recycle the withdrawal gas from the regions of 3TP1, 3TP2 and AP1.

Wells, Gathering Lines & Pipeline Design

Public perception is that there is significant experience with pipeline design and that CO_2 is relatively benign. Those in the industry know that this is not the case and that special design considerations need to be implemented when constructing facilities for processing and pipelining CO_2. At the time TPAO's pipeline was being designed, there was only one carbon dioxide pipeline in the world having any operating experience. This was the landmark gas-based EOR project, SACROC pipeline serving the Kelly-Snyder field in Texas [(2)].

The principal design criteria for the Dodan wells had been the extensive corrosive environment. The production casing is 6 5/8" J-55 and is cemented in 8 5/8" hole and into the surface pipe. The tubing is 2 7/8" in grade L-80 with epoxy coated internals. Producing formation is isolated by hydraulic set permanent packers at the top. Wellhead, gauges, needle valves, adjustable choke and master valves have been trimmed for H_2S and wet CO_2 service.

REVIEW OF THE PROJECT PERFORMANCE (EARLY PHASE)

Following resolution of various problems affecting plant startup at Dodan, CO_2 injection at B.Raman commenced on March 1986. After the start of injection, each well showed a different behavior, but the general response can be grouped in two categories. The wells located at the northwestern part of the pilot area had poor injectivity and wellhead pressures rose up to 1200-1400 psi before substantial amounts of CO_2 could be injected. On the other hand, wells located at the eastern and southern portion of the pilot were able to receive gas at rates 1-2 MMSCFD at stabilized wellhead pressures of 700 psi. The wellhead pressures in these wells never increased although injection rates were increased. The required bottomhole pressure for "huff and puff" process was never achieved. Some of these wells are still injectors with somewhat declining wellhead pressures [(3)].

During the project application, pressure development in the reservoir was observed by periodic surveys. The bottomhole pressures which were around 400 psi before the start of project application rapidly increased to around 1300-1800 psi level after a continuous injection was resumed. It was observed that the gas generally tends to migrate in porous and fractured areas towards the structurally higher portions. It is concluded that the reservoir at northwestern part of the pilot is a single porosity system while the remaining part has the characteristics of a dual porosity system with fractures and fissures forming the main flow channels.

Water injection was initiated into four wells in the east of the Demonstration area on September 22, 1986 in order to help the injected CO_2 to be kept in pilot area (Fig-3) and further to build up reservoir pressure. Most of the wells that were previously shut down because of the low reservoir pressure in the pilot and vicinity areas were put back on production as fluid levels increased due to gas injection. But, the rises in fluid levels did not create a proportional production increase because of inefficient performance of subsurface pumps [3].

Because of the fill up time required to pressurize the depleted reservoir, the ratio of injected CO_2 to incremental oil production was very high initially. It started to come down as production started to increase. The GOR between 3 and 5 MSCF/STB indicates an efficient and the most economical process.

From the field observations and the simulation studies carried out by using the performance data, the following were interpreted as the early remarks: (1) A considerable amount of oil is produced due to the high flooding effect of gas. (2) The reservoir behavior is clearly dual porosity (3). Diffusion of carbon dioxide into the oil is an effecting mechanism.

Expansion Plans

Having evaluated carefully two year performance of CO_2 injection both as "huff and puff" and "CO_2 flood" application, TPAO decided to extend the process to the rest of the field in stages. A definite injection pattern was not followed.

All the wells in the pilot area were completed with packers because of proposed "Huff and Puff application. Gaseous pumps were used to avoid gas-lock problem but these pumps did not perform well in case of free CO_2 gas flow from formation to wellbore. In April 1990, it is started to deepen the wells and place the pump intakes (perforated tubings) below the perforations. By this way, most of the problems in pumping were avoided [3].

To extend the application we had to construct the third separation station and expand injection pipeline network. It took less than a year to expand injection pipeline network. As soon as the injection lines were completed and injection wells were prepared, CO_2 injection started from injectors even though the separator station was not ready and it took two years to complete the construction of separator station (AP1). The region was pressurized and production of the wells increased by combined effect of increased pressure and improved oil characteristics. We observed production wells very closely and did not let gas to breakthrough in any production well by controlling injection rates until AP1 separation station was ready in mid 1990. GOR data, pressurizing program of the new injection regions and pressure surveys of the field were used to determine the optimum total injection rates [3].

In early 1988, TPAO decided to recycle the produced gas. Design, order, manufacture, construction and start up activities of recycling facilities took more than three years. 20 MMSCFD capacity recycling and dehydration facility was completed and put in operation in mid 1991. The recycling cost for 1 SCF of CO_2 is almost the same with Dodan facilities operational cost.

Overall Performance of the Field

As of January 1993; application was expanded to whole field in terms of injection and today, 95% of the field's production wells were affected by injection. Full field application including separation systems has been entirely accomplished by 2000.

In early 1986 before CO_2 injection started, average production rate per well was around 25 BPD. As the production wells were affected by injection, average well production of the field increased. Especially after lowering pump intakes below perforations, most of the wells reached 100 BPD in mid 1991. Some of the wells were produced as high as 200-300 BPD for a short term. But now average production is around 40 BPD (Fig- 4).

Having observed production rate increase in every well affected by injection, TPAO started to open infill wells to increase production and to reduce spacing to 31 acres. By the end of 2006, 102 infill wells have been drilled and put on production since 1987. Production performance of the infills drilled in western part of the field is usually not sufficient, and either those new infills or some of the nearby wells were obliged to be shut down for the reason that the high GOR from time to time. In that case, the process reducing the spacing less than 31 acres was terminated in western.

Figure 5 shows CO_2 breakthrough trend of the field. GOR of some wells goes up to 20-30 MSCF/STB, but is controlled by injection rate adjustment of effecting injectors. If GOR of any producer can not be lowered to a desirable level, the producer and/or injector are shutted-in for a period of time. However from the beginning of 1992 producing and injecting GOR of the field started to increase. A GOR in the ranges of 10 MSCF/STB is implicitly recognized as an upper limit to be allowed at individual well stream and operators in the field perform accordingly.

At the beginning of injection; reservoir pressure was around 400 psi and at this pressure level there was weak water influence from the aquifers with three different salinities. After injection commenced, due to pressure increase in the reservoir, water cut of the wells decreased especially in the western part of the field (Fig-2). In 1992 due to slight pressure drop because of increasing GOR, a slightly increasing trend in water cuts started. This trend inclined up with reinitiating of WAG in year of 2000.

During no injection or interruption of CO_2 injection, water cut in north, and southwest of field, generally increased and quite a lot of mechanical problems in pumping system was recognized indicating active water influx. Incremental oil rate declined at the same time. Daily oil production on the whole field increased noticeably for about 15-20 days, following the resumption of injection and then decreased to the steady trend. From the foregoing, it is inferred that termination of injection for short periods do not let significant production loss and the loss of production at that time compromised by the excessive increase on resuming injection. It can be concluded that the dissolved gas in matrix in a relatively higher pressure forces oil to flow through the fractures, following the reduction in pressure in the secondary porosity medium(3).

A simulation study performed in 1996, also including the parameters obtained by the wells drilled in 1986 and the dynamic reservoir data recorded during the entire operating life of the field, and it showed existence of an active water influx in the field but, besides that the total gas reserve is higher than that the calculated previously. It is calculated that there is a 337 BSCF gas in Dodan field.

As of December 2006, a total of 274,4 BSCF of CO_2 has been injected, 195,0 BSCF has been produced back and 75,7 BSCF of gas has been recycled since 1991 (Fig-6). Daily production of the field is about 7000 STB from 204 producers. Totally, 94 million STB of oil have been recovered, representing 5 % of the estimated OOIP. The portion of 57,9 million STB of it is incremental.

CURRENT APPLICATION PROBLEMS

Dodan CO_2 Reservoir and Surface Facilities

Some time after startup of Dodan facilities, it was noticed that there was considerable wax floating on the collected hydrocarbon condensate from production and test separators. This wax was seen when the CO_2 production wells were blown at the wellhead. When the lines were disconnected at the wellhead, it was noted that the gathering lines had a wax coating. One well was completely plugged. Hot water was injected to the gathering lines from the facility. Paraffin inhibitor was injected to the gathering lines to dissolve the wax and a larger filter was placed to the downstream of separators to prevent the wax carry over.

Regular inspection of Dodan equipment for corrosion monitoring is performed and metal thickness of the critical equipments is measured. A number of interior cracks at shell of H_2S absorption towers were detected during the first periodic inspection in 1988. The cracks were repaired cautiously.

Existence of H_2S in well stream causes extremely rapid and augmented corrosion in tubings and casings in wells. TPAO installed in the Dodan wells J-55 carbon steel tubing and packers internally coated with epoxy resin. A punctual corrosion was observed in the wells having string with holidays in the coatings or leakage at packers.

CO_2 Pipeline between Dodan and B.Raman

A corrosion inhibitor injection system has been provided as a precaution. Extruded polyethylene coating and cathodic protection were specified for the pipeline. Inhibitor between two pigs is injected to the pipeline at a regular basis, figures regarding with the cathodic protection are recorded regularly and remedial procedures were performed in case it is needed.

Since the beginning of the project, two different cracks were detected in the pipeline. The reason of the first failure was the landslide. A weld defect/lack of fusion at the pipe was the cause of the second failure. Repairment of pipeline was performed in accordance with the applicable original standards and specifications.

Bati Raman Field

It was anticipated that the injected CO_2 slug could cause a variety of problems including corrosion and pump problems, wellbore annular freezing, reservoir channeling and low injectivity in the existence of water in the environment. CO_2 related corrosion problems in production wells are minimal, possibly due to viscous heavy oil coating of steel material by the B.Raman crude. Erosion/corrosion of rod boxes and subsurface pumps has been severe in the areas where there is even a moderate water cut. This field experiment has confirmed a considerable, speedy corrosion in gas, water and waste water injection wells having communication between the tubing and the casing.

Both in producers and injectors, communication between casing and tubing should be corrected as early as possible and the casing/tubing annulus needs to be treated with a suitable inhibitor. Corrosion problems have been minimized through chemical injection and proper selection of materials.

The CO_2 injectivity index in all the injection wells improved with cumulative CO_2 injection and the wellhead pressures decreased during the life of the project. One of the problems encountered during CO_2 injection was ice plugs forming in the injection lines and tubings. Annular wellbore freezing occurred while injecting CO_2 in the wells at which wellhead injection pressures were extremely low. Occasionally, abnormal annular pressures at some of the wells have been recorded.

Sucker rod pumps have remained the optimum artificial lift method for most wells. Increased gas volume decreased the overall efficiency of the downhole pumps. Special design gas anchors have been used in the field. Using properly selected Progressive Cavity Pump (PCP) even in the wells having quite viscous emulsion seems attractive and some remarkable results have been encountered recently. These pumps efficiently handle heavy viscous oil and fluids with high content of water and/or moderately low content of gas.

Horizontal and Multilateral wells

Horizontal and multilateral wells have become one of the leading technologies in the oil and gas industry today. They have the potential to increase dramatically the efficiency of hydrocarbon recovery through extended and flexible reach to the formation where conventional wells have limitations. A range of geometrical configurations is available to provide the optimum economic benefit in reservoir scenarios. To achieve the best results from a multilateral well, compatible completion equipment and method of completion must be properly selected as well.

Principle advantage of those wells are higher productivity indices, decreased water and gas coning, increased exposure to natural fracture systems, and better sweep efficiencies. On the other hand, there are a number of published papers calling attention to the remarks controversial with these considerations. F.C.J. Mijnssen at al (SPE 84939) indicates that new horizontal wells produced significantly more oil than the original vertical wells at the beginning. However, later on horizontal wells produced similar amount of oil as the vertical wells, but with much water cut. It is concluded that high density horizontal infill drilling has resulted in sub-optimal sweep. It is a situation roughly analogous to such an EOR system comprising high specififc gravity oil and horizontal wells; at least, an extensive breakthrough and recycling of CO_2 through the horizontal legs are anticipated.

Effect of new well architectures on sweep efficiency is poorly understood. TPAO is investigating the performance of both the new and old horizontals thoroughly. One important thing that makes us hesitate to drill the conventional horizontals is the pump off effect due to CO_2 that causes pump failures. The wells with more frequent failures are intensifying in the high GOR areas. For minimizing this problem, placing pump intake below the productive Garzan formation- as deeper as it can- is the common application in the field; both, for verticals and horizontals. So, this would be another, but the most important parameter for us to keep in mind when designing a well profile. In horizontals drilled in 90's, pump intakes (perforated tubings) could have not been placed below the perforations due to the technical and economical circumstances of the age. Furthermore, we were obliged to set intakes high above the Garzan formation to stay away from latent mechanical problems which might be initiated by high dog leg severity. With the latest technology and economics, new horizontals, having a vertical leg, were designed and drilled to overcome this effect in 2005 (Fig-7). But now a new problem on stimulating or making individual operation on each leg arose. Logging the horizontal sections and presetting the permanent diverting shoes in the course of drilling were itemized costly. Using coil tubing and implementing special treatments (e.g., stimulation with self diverting acid) is really expensive for a field having production rate of 40 bpd/w. Entering the horizontal legs and stimulation of the wells are being achieved with trial and error method.

Stimulation of the wells delivered a slight production increase. But, with these figures, horizontal/multi-lateral/slanted wells drilled in B.Raman do not contribute to the production far too much, for the time being. Studies on horizontal well design and a better placement are still under process.

Review- Status Quo

Most of produced gas with the oil is currently recycled with this system of 1991 vintage, releasing excess amounts to the atmosphere. Therefore a new recycling system now was purchased intending to recycle the excess breakthrough gas which will increase gradually over the oil field life time. Electrical motor with variable frequency drive (VFD) system will be used as driver. VFD system will allow the compressor more flexibility for the rate control and cost reduction of recycling gas. The gas will be made available from the oil-gas separators in eastern region of the field. Second recycling system is slotted for 2007.

Percent Oil Recovered (POR) versus Injected Gas Volume (IGV) figures are given at Figure 8 and 9 for full field and for the western region of the field, correspondingly. Because of the fill-up time required to pressurize the depleted reservoir, the volume required to produce incremental oil is high initially, and a high inclination occurs in POR versus IGV figures. Gas injection in each region of the field initiated at different phases of the project, from 1986 to 1993. In parallel to the establishment of the gathering stations with separators, injection with full performance were made late up to year of 2000 in east of the field. POR versus IGV or POR versus Time figures for each region tend to follow similar paths, but they are shifting in parallel with the commencement of injection with full performance. A semi-log correlation can be used to model this relation. It is obvious that these correlations will not have validity for a long run due to the reason of declining performance of CO_2. It is necessary to inject a huge amount of gas to the reservoir to be able to reach the expected recovery, up to 10%, even by assuming that all the variables regarding with the application preserved at the same level. This coarse correlation clearly dictates that Dodan resource must be conserved and applied to maximum advantage. To achieve these goals, maximum conformance control and reaching to a higher recycle capacity are the vital project to do's.

IMPROVEMENT OF BATI RAMAN OIL RECOVERY PERFORMANCE

With the implementation of the CO_2 flood, recovery has been expected to potentially reach up to 10% of OOIP (185 million Bbls). Recoveries to date appear to be at roughly one half of this level.

Bati Raman is a naturally fractured carbonate reservoir where the heterogeneities and the unfavorable mobility ratios between CO_2 and the heavy oil cause inefficient sweep of the reservoir. Extensive breakthrough and recycling of CO_2 volumes through the fracture and vug system has occurred, severely jeopardizing recovery.

During primary production, reservoir pressure in the west part of field decreased too much. Average pressure has been increased after carbon dioxide injection, but a large volume of CO_2 was needed to be injected at permanent injectors to raise and maintain reservoir pressure in subsequent era. Recently, over the course of field operations, the large recycle volumes of CO_2 resulted in many areas of the field being operated at comparatively lower reservoir pressures. However, the solubility of CO_2 within the oil is a significant factor for the successful operation of a CO_2 flood and it is highly sensitive to reservoir operating pressure. So, increasing the reservoir pressure has a vital importance on managing the recycled gas volume. Within the context of current field operations, the major reservoir performance issue has to be overcome is poor conformance. The problem of conformance is especially urgent, in the area where sharp pressure drop is observed.

Within July 2002 and August 2004, TPAO performed two pilot applications of a conformance improvement fracture-plugging (flowing) polymer gel system in three wells and four wells, consequently. With flowing gel treatments, it was attempted to plug the fracture system within the vicinity of injection wells. This provided a favorable, short term response, further confirming that the predominant limitation with the current CO_2 flood is bypassing of the reservoir matrix through the fractures, greatly reducing the sweep efficiency of the CO_2.

Monitoring the injectors and the offset wells showed that the gelled volume around the well is influenced and demolished by CO_2 injected following gel application at a certain pressure and the CO_2 discovers new flow channels in the region for a while and later on meets the old channels. Although the long term stability in wellhead injection pressure of injectors was observed , it is concluded that a significant drop in GOR of offset wells and a considerable increase in incremental oil could be achieved only in short term with these applications (Fig-10).

It is also desired to give support to the CO_2 injection with viscosity augmented water injection. This would result in minimizing the by-passed and shielded areas. Additionally, CO_2 displacement process can be improved if the mobility of the CO_2 can be decreased. One of the ways to do this is to disperse the CO_2 as foam in a continuous phase. By considering that the foams are so effective in controlling gas mobility, TPAO has started to investigate this issue and contacted several manufacturers of foam chemicals to be able to start the lab tests and decide to purchase suitable one for field pilot application. A couple of laboratory tests have been executed to investigate the best fitting water viscosity enhancing compound and/or foaming agent, but unfortunately all the shots implemented up to now have failed for a commercial application. They do not seem promising and, as a consequence, conventional WAG and/or peripheral water injection are in progress for now.

Another issue might be considered in CO_2 application is the continuous pattern modification approach in order to create new injection profiles that reduce the adverse effect of preferential flow of injected gas through high permeability zones. But, it is extremely important to determine the prospective wells to be employed for this objective and decide on when the right time is to switch the well form production to injection or, visa versa, to reach the highest possible value of ultimate recovery at the end of application.

CONCLUSION

Bati Raman immiscible CO_2 injection project has been acknowledged as one of the most successful EOR applications in the history of heavy oil in fractured limestone reservoirs. Taber at al (SPE 35385) have lowered the oil gravity requirement to >12 ^{o}API for immiscible CO_2 flood to include this successful 12-13 ^{0}API project in Turkey. On the other hand, notwithstanding what may appear as a dramatic increase in oil production, it is far below what the simulation studies predicted.

Despite ongoing problems, the Bati Raman reservoir clearly presents a significant development opportunity for recovery improvement. With existing infrastructure in place, even a 1 - 2% increase in ultimate field recovery can result in the order of a billion dollar increase in cash generation from production. Over more than 20 years of injection, the recovery peaked at ~13,000 bbls and began to decline reaching today's ~7,000 bbl value. This decline indicates that the CO_2 injection needs further support to sustain at least this productivity or even increase it to higher amounts.

The current needs and the amount of potential would be gained from this field require the evaluation of the issues at two stages: (1) short term, and (2) long term. The objectives of TPAO's efforts cover both aspects and look for solution methodologies.

With the objective of rejuvenating the Bati Raman asset, TPAO built a multidisciplinary field optimization team to meet the objectives of project on a technically and cost efficient basis.

The multidisciplinary approach started by performing a series of meetings to define the challenges in that mature stage of application, identify the applicable solution, restore the declining oil production and carry out studies to investigate various "what –if" scenarios. This approach, throughout the project execution, will bring the first level of optimization. The subsequent objective is to generate plans for designing and implementing new reservoir management scheme to improve the ultimate recovery by the application of supplementary recovery systems such as steam. This will provide ways to establish a systematic field management environment for the field as well. The recent higher rates of decline impeded and production ranged up to 7000 BPD from 5500 BPD, as an early fruitful result of the new reservoir management scheme.

Strategies for Immediate Term

Primary objectives to be focused on:

(1) How the application could be optimized for achieving the higher oil production rates and slighter GOR as early as possible?

(2) What is the optimized well placement? How could the interwell spacing be optimized? What are the potential implications of further downspacing?

(3) What is the successful engineering and application work done up to date in order to give ideas on routes for establishing the future framework of the project?

(4) What techniques could be applied in zones that are totally or partially swept where no longer any benefit from the CO_2 injection is expected? What kind of injection strategies can be proposed in unswept zones?

Strategies for a longer timeframe

TPAO targets the following goals:

(1) Improve the current knowledge about the field to be sufficient for implementing the next phase of the EOR process.

(2) Establish a better understanding of the reservoir, especially for fracture characterization and oil PVT characteristics to investigate the benefits of steam injection.

(3) Interconnect all project activities to each other by a strong base of well documented, well developed representative field "living model" where the guiding models are used for designing field implementation plans and in return the response from the field activity is fed back to the "living model" for fine tuning.

Acknowledgement

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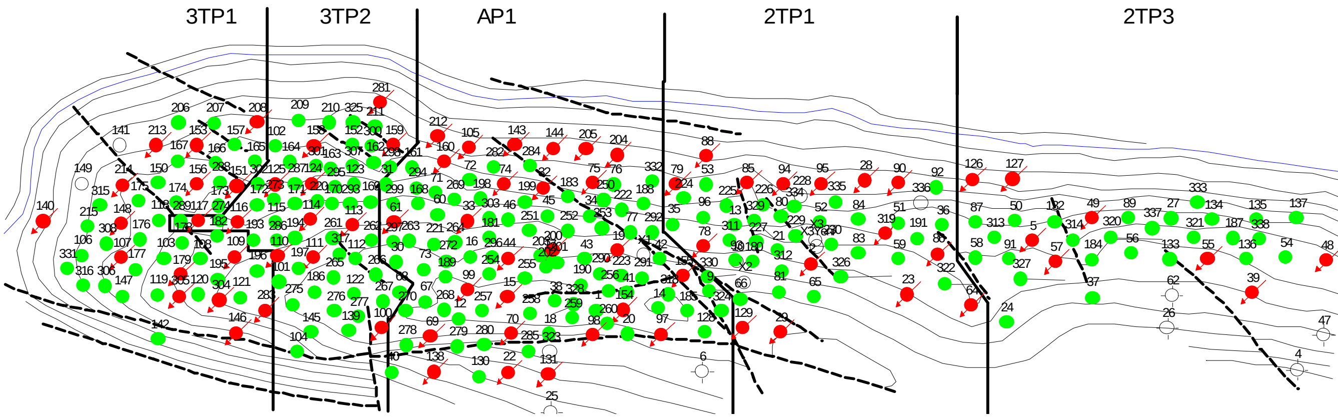

Fig. 1: Garzan Structure Map

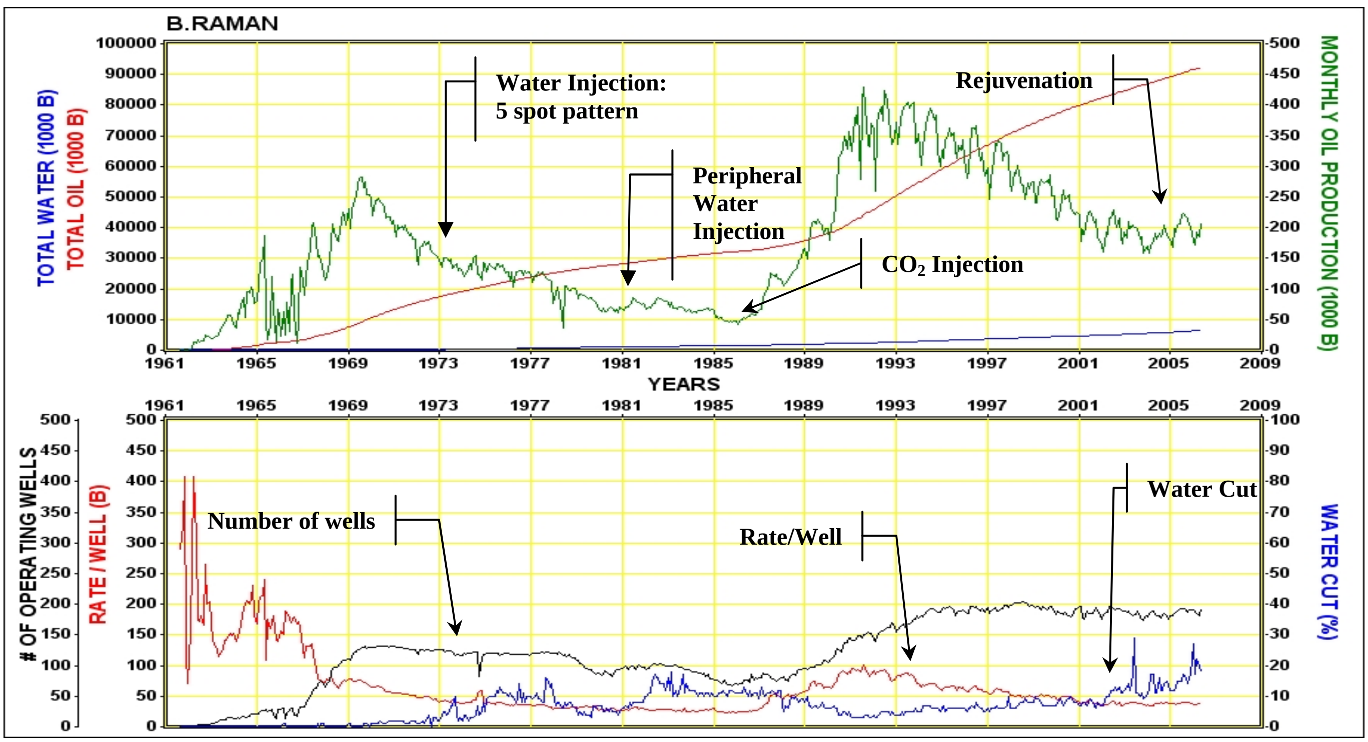

Fig. 2: Bati Raman Field Production History

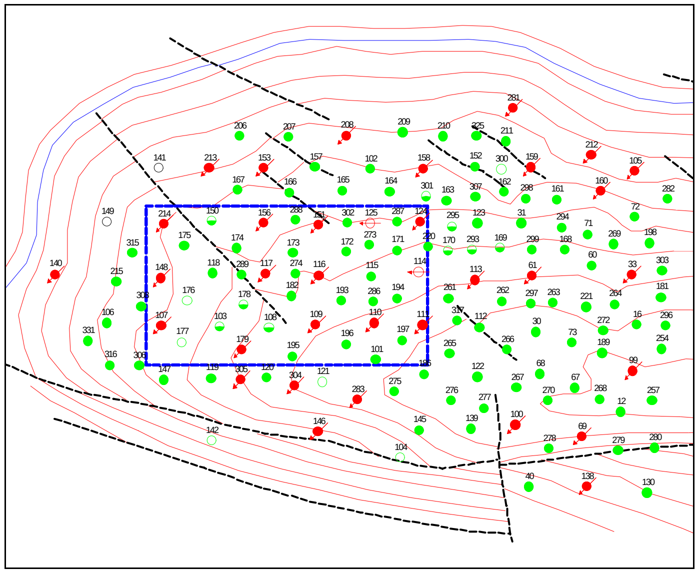

Fig. 3: Pilot Area

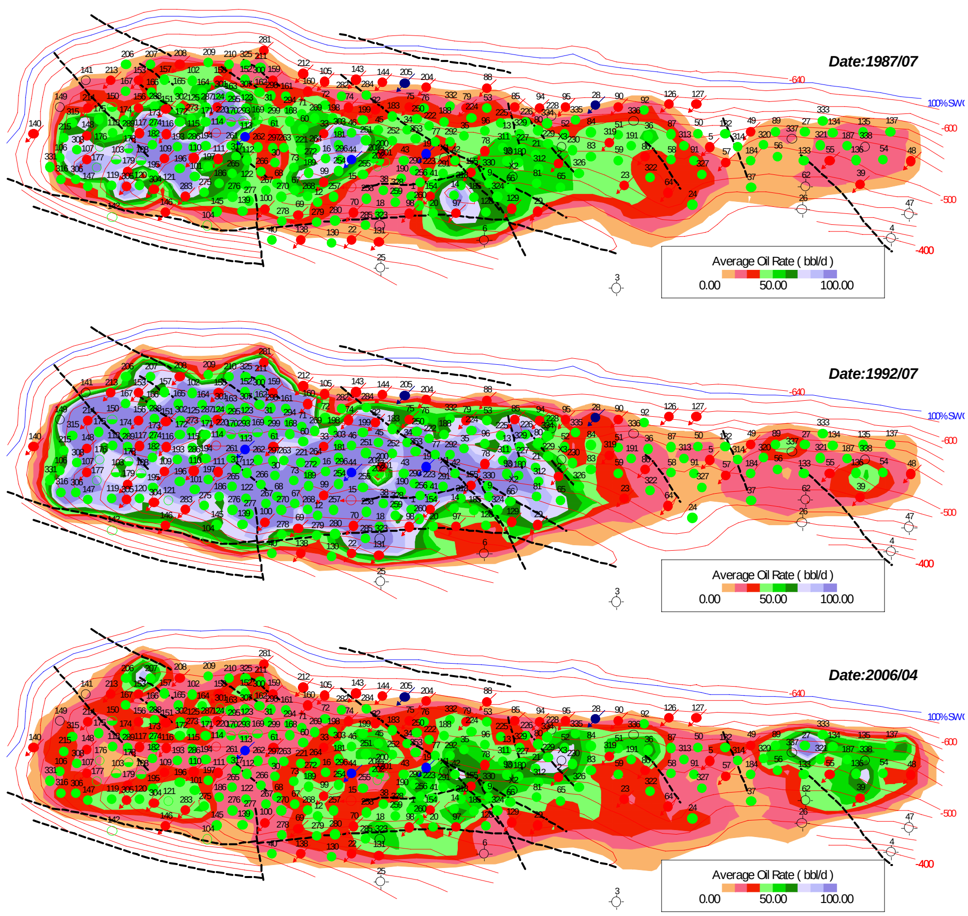

Fig. 4: B.Raman Field Average Well Production Rate

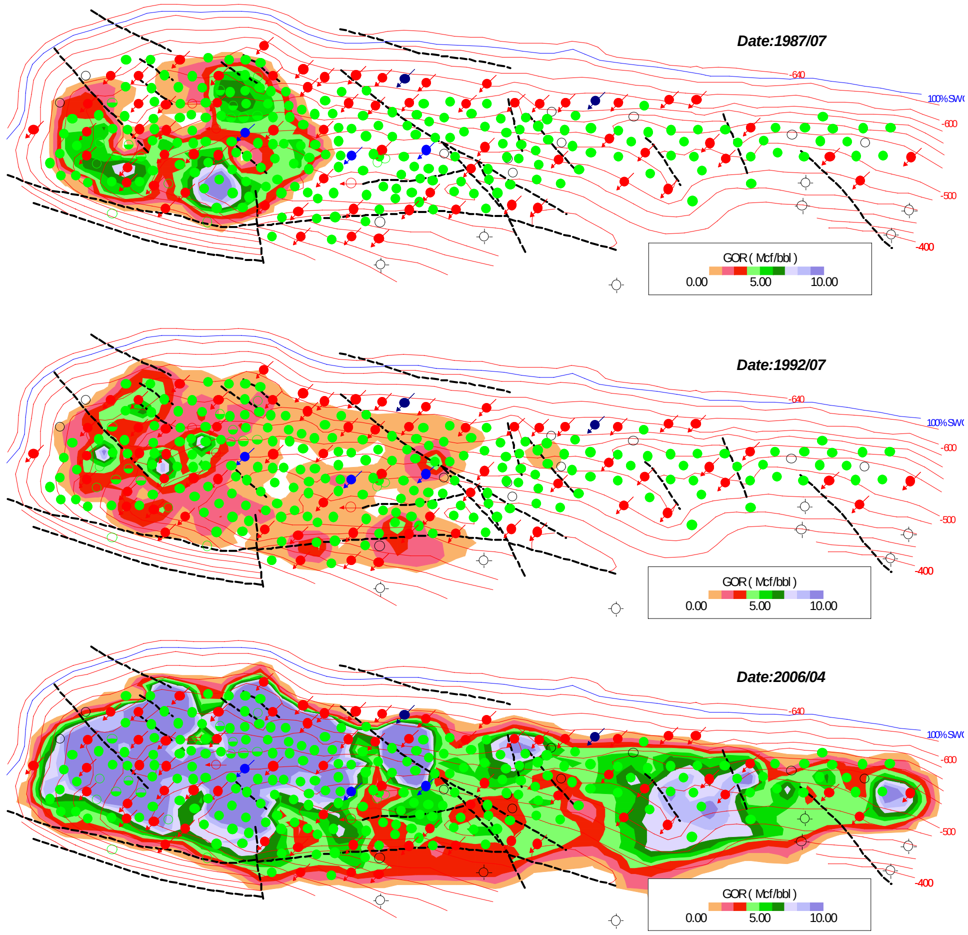

Fig. 5: B.Raman Field GOR (Gas Oil Ratio)

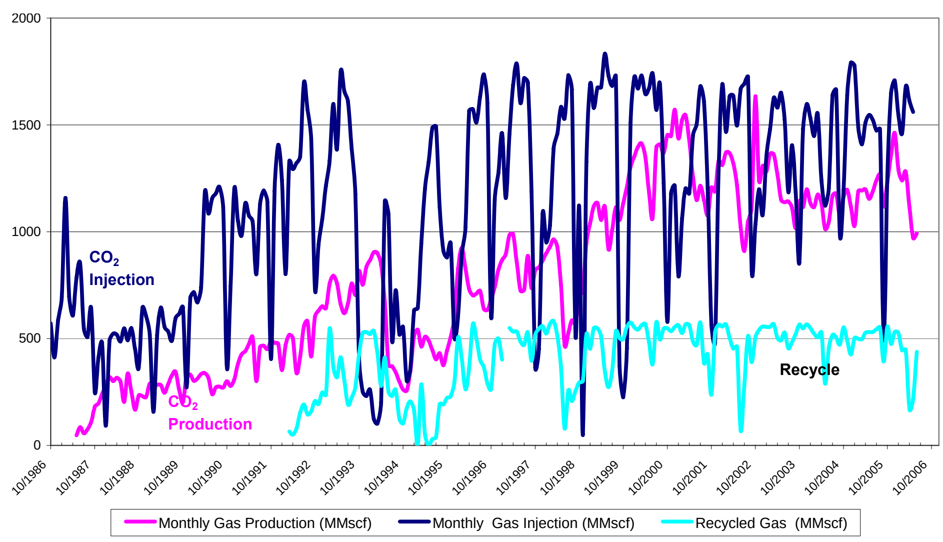

Fig. 6: B.Raman CO_2 injection efficiency

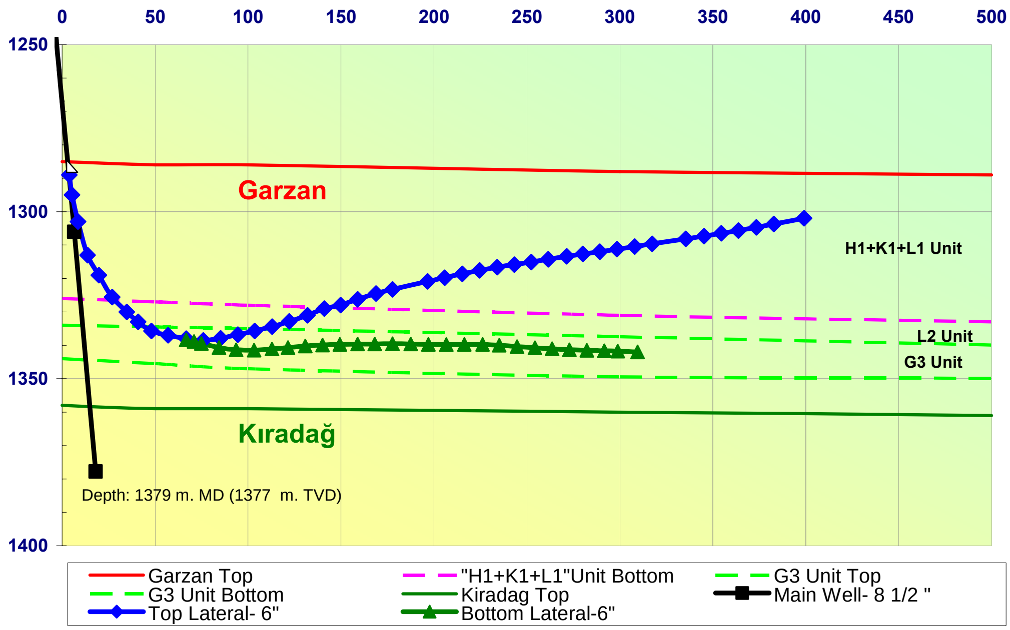

Fig. 7: Multilateral well configuration

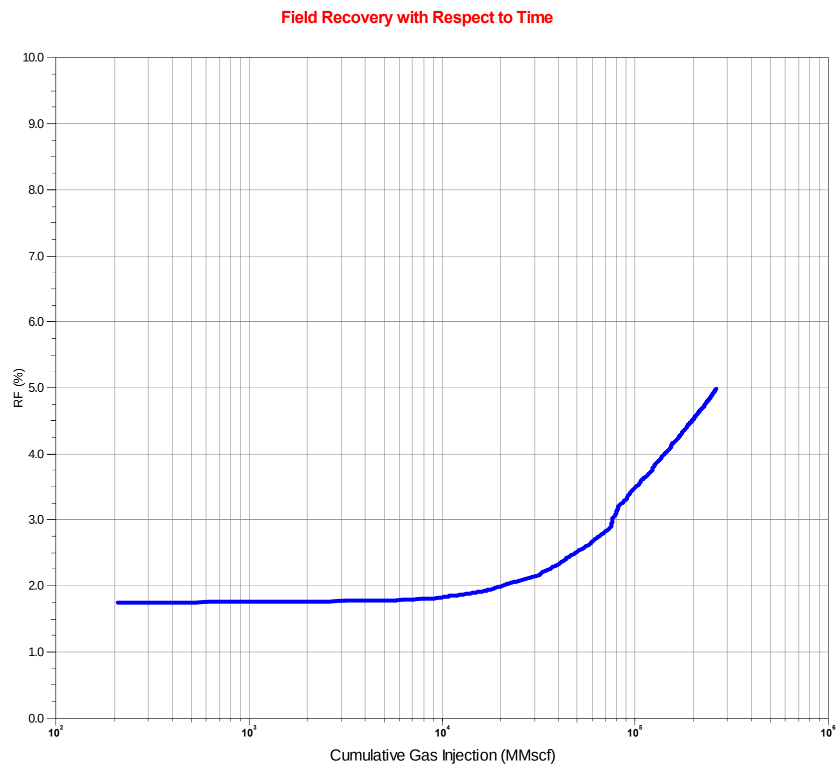

Fig. 8: Field Recovery vs Cumulative injection Volume

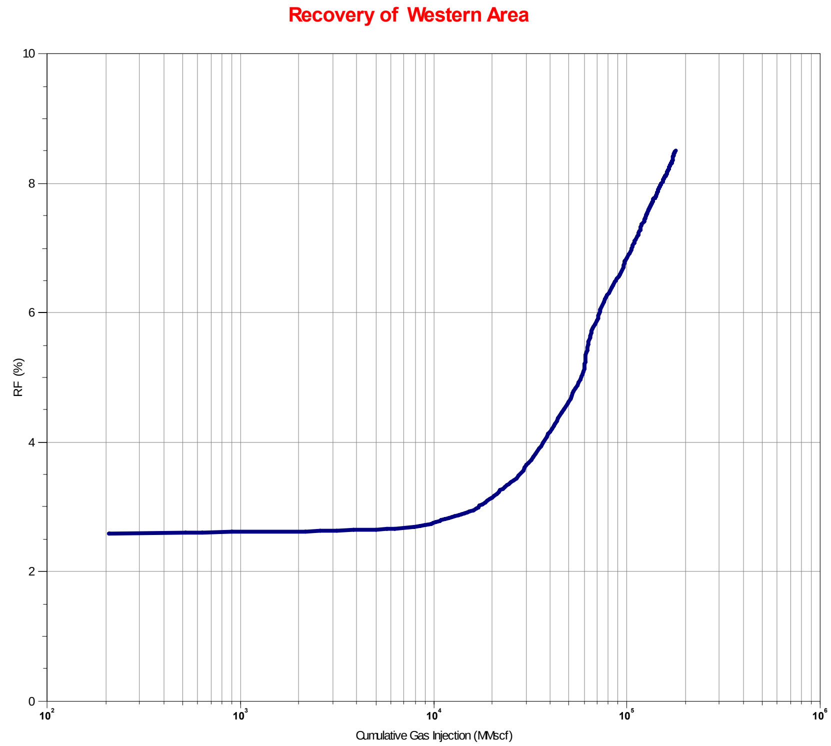

Fig. 9: Field Recovery (west) vs Cumulative injection Volume

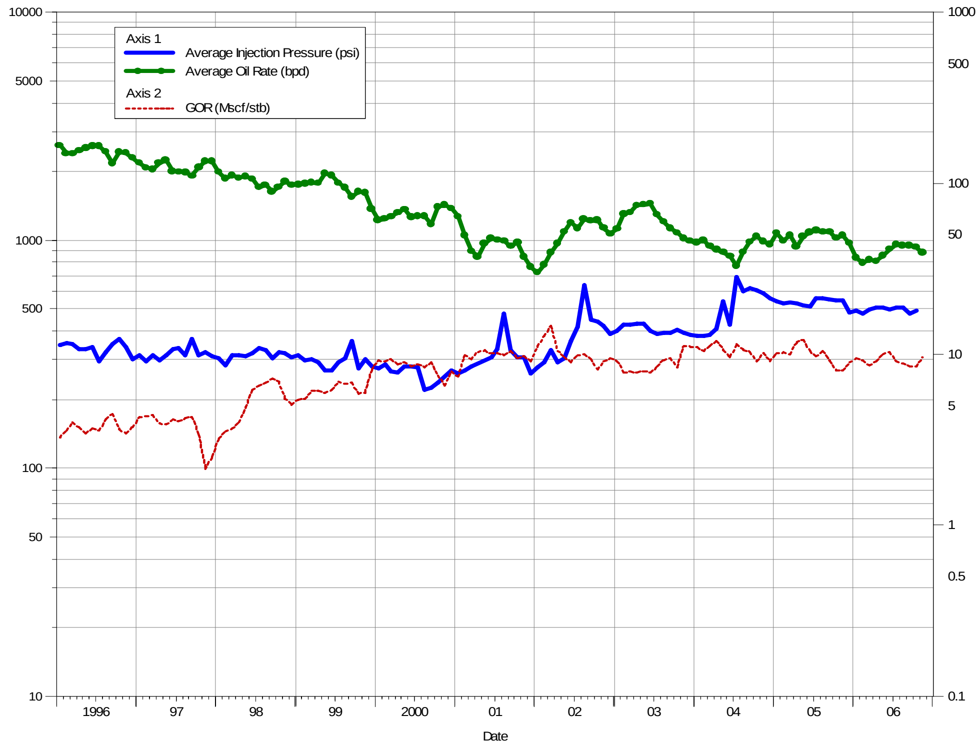

Fig. 10: Gas injection rate and pressure behavior after the gel treatment operation