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DUAL ENERGY GAMMA-RAY ABSORPTION TECHNIQUE APPLIED TO OIL RELATIVE PERMEABILITY DETERMINATION DURING A TERTIARY GAS GRAVITY DRAINAGE EXPERIMENT.

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ABSTRACT

For several years a dual energy gamma-ray absorption measurement apparatus has been routinely performing in situ three phase saturation monitoring during coreflood experiments in reservoir conditions. This paper presents this sophisticated equipment and the application of the technique to determine the three phase oil relative permeability at low oil saturations during a tertiary gas gravity drainage experiment. The test was carried out on a 58 cm long composite of a water wet reservoir sandstone. The oil relative permeability was a crucial point to validate the economic feasibility of this tertiary oil recovery process for a waterflooded reservoir in South-East Asia.

Using the gamma-ray absorption technique it was possible to visualize the fluid saturation distribution in the core as a function of the volume of gas injected. The production of tertiary oil by gravity drainage was put into evidence at the top of the core. The three phase oil relative permeability curve was deduced from the oil saturation profiles using an analytical calculation.

The experiment was finally correctly reproduced with a generalized compositional simulator, emphasis being put on the match of saturation profiles. A triphasic relative permeability model was then validated and will be used for field-scale simulation.

INTRODUCTION

The declining oil production from large waterflooded reservoirs after several decades of exploitation and the significant amount of oil still remaining in place are of great concern for oil companies and fully justify their interest in tertiary recovery processes. However these processes such as gas injection, water alternate gas (WAG) injection or gas gravity drainage in waterflooded reservoirs all involve three phase flow and, consequently, are much more complex to handle than the now well-known two phase processes.

As surveyed by R.E.Guzman et al.[1], the numerical simulation of three phase flow is often the weak point in our quest to understand and predict the phenomenon. Several theoretical three phase relative permeability models are available, Stone models being the most commonly used, but the choice between one or another more often proceeds from the experience or intuition than from the confirmation of suitable experimental data. It would not be such a serious issue if the total additional oil recovery and its dynamics predicted by the simulation were not so drastically dependent upon the three phase relative permeability model used. Decisions about the economic feasibility of field developments based on such doubtful simulations remain hazardous and may lead to unexpected results.

Special effort was devoted in our laboratory to design and perform experiments which can better support the choice of the three phase relative permeability model. Capabilities for steady-state and centrifuge measurements were greatly improved with the acquisition and development of new apparatus. As related by P.Grivot et al.[2] these methods were applied to the determination of two phase and three phase relative permeabilities.

The in situ fluid saturation monitoring became an essential tool for the interpretation of multiphase flow. It provides valuable information concerning the fluid distribution in the core and may reveal capillary end effects which are known to strongly affect the determination of relative permeability. Concerning coreflood experiments in situ imaging techniques allow to visualize the fluid displacements and to ascertain initial and final fluid saturation distributions in the core such as the irreducible water saturation profile or the residual oil saturation profile. Without these capabilities the pressure vessel in which the core is confined appears like a "black box", the tested oil recovery mechanism can then only be quantified from the material balance between what goes in and what goes out. Unfortunately, in case of non uniform fluid saturation distribution, generally due to capillary end effects, the average fluid saturation determined by the material balance may be misleading and does not reflect the real efficiency of the mechanism. This statement is particularly true for gas gravity drainage experiment for which the residual oil saturation distribution is expected to be strongly non-uniform.

This paper presents our in situ imaging capabilities, the dual energy gamma-ray absorption measurement apparatus and the application of this technique to the interpretation of a tertiary gas gravity drainage experiment. This experiment was specially designed and performed in order to address the question of the determination of the three phase oil relative permeability at low oil saturations. This parameter was indeed a crucial point in the economic evaluation of this kind of project for future developments on a waterflooded reservoir in South-East Asia.

EXPERIMENTAL EQUIPMENT

The dual energy gamma-ray absorption measurement rig was designed to study multiphase flows in reservoir representative cores. It was described by C.Barroux et al.[3] and is schematically represented in Figure 1.

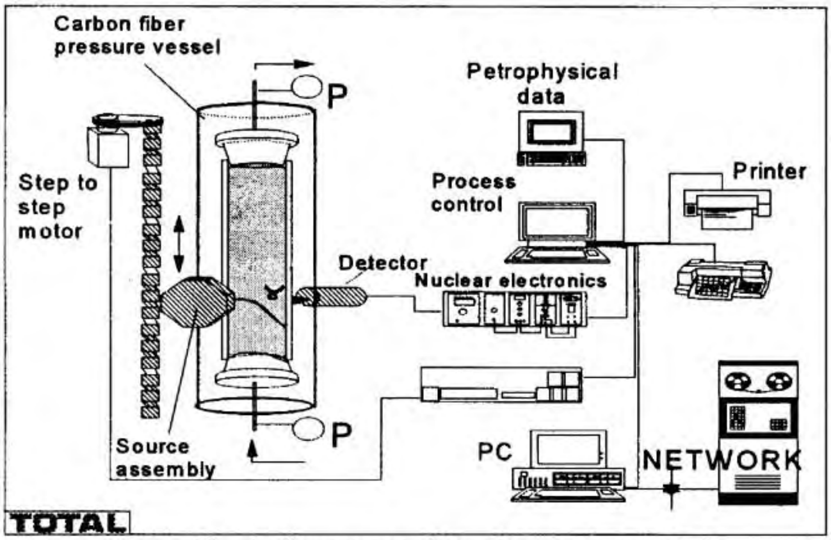

Fig. 1 : Gamma-ray absorption measurement rig

The Hassler type pressure vessel can handle cores up to 66.5 mm in diameter and 840 mm in length. The barrel of the cell is made of carbon fiber in order to minimize the gamma-ray absorption due to the core holder. The highest operating pressure and temperature conditions are 150°C and 450 bar.

The source and detector blocks move together along the core. The source block is a cylindrical tungsten-alloy shield coated with stainless steel. It contains two sealed radioactive sources :

^{241}Am (Americium), activity 360 mCi and energy 60 keV

^{137}CS (Cesium), activity 30 mCi and energy 662 keV

which can irradiate the core alternatively through a 7 mm diameter collimator. The detector block is composed of a sodium iodide crystal coupled to a photomultiplier and is also collimated. The core holder is mounted on a pivot and in situ saturation measurements can be performed horizontally or vertically.

The source/detector assembly is moved step-by-step along the core. At each station the core is irradiated by the Americium source during a previously defined but adjustable time, then the Cesium source irradiates the core. Generally each absorption measurement takes 300s to be completed. The number of emitted γ-photons per second fluctuates around an average value R and follows a Poissonian law with a standard deviation of $\sqrt{R}$. The count during a period t of time will give a value of $R\,t \pm \sqrt{R\,t}$, corresponding to a mean count rate of $R \pm \sqrt{R/t}$. It follows that the longer the acquisition time the better the precision of the measurements. However during a coreflood experiment the acquisition time should be short enough to be able to follow the phase displacements. It is then necessary to find a compromise between these two conditions in order to have accurate data and to follow, for instance, the frontal displacement in the core.

EXPERIMENTAL PROCEDURE

The experiment was designed and performed to simulate in the laboratory a tertiary gas gravity drainage in reservoir conditions on a long reservoir core. The objective was to ascertain the three phase oil relative permeability during this process.

Care was taken in the choice of the fluids. The oil was a synthetic mixture (66.1%C1-33.9%C7) and the gas (93.6%C1-6.4%C7) was the equilibrium gas at experimental conditions (230 bar and 71°C). This choice was made in order to avoid uncertainties on fluid properties and to reduce the gas/oil interfacial tension. It was indeed essential to maintain the IFT as low as possible so that the capillary end effects did not disturb the tertiary oil production. With low IFT it was expected to actually visualize the residual oil saturation profile with very low oil saturation at the top of the core. Moreover numerical simulations revealed that the injection of non-equilibrium gas may not be recommended because the expected reduction of oil saturation at the top of the core would be totally masked by significant compositional exchanges.

A dopant (ortho-iodotoluene) was put (50g/l) into the oil phase in order to enhance the contrast between oil and water for good gamma-ray absorption differentiation. A comprehensive calibration procedure was carried out to ascertain the γ-absorption coefficients of each fluid before the experiment. These coefficients were precisely deduced from the measurement of the attenuation of the gamma-ray beam across a glass bead column, 100% saturated with one fluid.

Core preparation

A 58 cm long core was assembled from 4 water-wet sandstone reservoir core pieces. The core was coated with a two layer composite of non metallic resins. This assembly was resistant to water, solvents and hydrocarbons, gas impermeable and could support high temperature and pressure for a long time without any damage.

After cleaning with usual solvents (chloroform, toluene and alcohol), the core was vacuum saturated with brine up to the experimental pressure 230 bar and the absolute permeability to water measured. The core was then flooded with refined viscous oils to connate water saturation and the oil mixture was eventually injected in reservoir conditions 230 bar and 71°C to replace the viscous refined oil. The main results are given in Table 1. The porosity and the irreducible water saturation distribution along the core were ascertained by the gamma-ray absorption technique and are illustrated in Figures 2 and 3. The calculation of fluid saturations from gamma-ray absorption measurements was explained by C. Barroux et al. [3].

TABLE 1 : Core characteristics

Length	58.6 cm	
Diameter	6.5 cm	
Pore Volume	517 cm3	
Kw	100 mD	
Ko (Swi)	110 mD	
	by mass balance	by in situ measurement
(mean) Porosity	26.40%	27%
(mean) Swi	32%	31%

Secondary water flooding

The synthetic brine was injected vertically upwards at a constant rate Q=10 cm3/h until the production of oil totally ceased. The fluids were produced at the top of the core into an ambient condition separator.

Tertiary gas gravity drainage

The synthetic equilibrium gas was injected vertically downwards following a sequence which was optimized from numerical simulations. At first the gas was injected at a high rate Q = 40 cm3/h during 3 hours in order to contact a large quantity of oil avoiding gas breakthrough. The advance of the gas front was controlled by gamma-ray monitoring which revealed that the maximal oil volume was indeed contacted by the gas without gas breakthrough. Then the gas injection was stopped and the core isolated for 15 hours. The gas was expected to flow upwards during this period and create a gas cap. Finally the gas injection was resumed at a slow rate Q = 1cm3/h in order to produce oil and feed the gas cap. This gas injection sequence is quite different from the usual gas gravity drainage procedure. The idea of the rapid injection phase was to produce water as fast as possible.

EXPERIMENTAL RESULTS AND DISCUSSION

Secondary water flooding

The production of oil and water is shown in Figure 4. The water breakthrough occurred at 0.49 Pore Volume of water injected with an oil recovery of 66% IOIP (Initial Oil In Place). After 1.9 PV the production of oil had totally ceased with a production water-cut between 99% and 100% and the water injection was stopped. The average residual oil saturation was calculated to be Sorw = 20.4%. The total oil recovery was then 70% IOIP. This very high oil recovery is probably related to the low oil viscosity (0.07 cP).

During the water injection the fluid displacement was monitored by the in situ imaging technique. The evolution of the oil saturation distribution in the core is illustrated in Figure 5. It corresponds to a piston like displacement whose front was followed until water breakthrough. The residual oil saturation profile is not uniform even if its average value (18%) is close to the Sorw obtained by material balance. The oil saturation reaches 35% in the upper part of the core while it is only 10% in the lower part. Capillary end effects are then significant and were revealed by the in situ saturation measurement.

Tertiary gas gravity drainage

At the beginning of the rapid gas injection (Q = 40 cm3/h) a significant compression of the injectant gas occurred and the inlet pressure increased up to 242 bar. Then the pressure slowly dropped down to the experimental pressure 230 bar as the gas started to penetrate into the core. During this phase only water was produced. The injection was then stopped for 15 hours, allowing fluid segregation to take place in the core. However the in situ saturation profiles (Figure 6) obtained during this period do not show any significant segregation.

The injection of gas was then resumed at low rate. After 37% Pore Volume of gas injected the tertiary oil started to be produced and the gas broke through simultaneously. The fluid production is illustrated in Figure 7. The oil production continued regularly until the time when the plugging of the core occurred at 1.3 PV of gas injected, probably due to the accumulation of fines at the outlet face of the core. The production of oil was still significant when the plugging forced the gas injection to stop. At that time the tertiary oil recovery was 57% TOIP (Tertiary Oil In Place) and the average oil saturation 8.5%.

For that kind of oil recovery mechanism where fluid saturation distribution is expected to be strongly non-uniform, it is essential to have in situ saturation measurements to get the correct assessment of the efficiency of the process. Figures 8, 9 and 10 show the evolution of the oil, gas and water saturations during the gas injection. The tertiary oil was produced from the top of the core. In the upper part of the column, the oil saturation regularly decreased to very low value. However a capillary retention zone seems to exist at the very top of the core where the oil saturation stabilized at around 10% while 20 cm below the top the oil saturation was down to zero. In the bottom half of the core the capillary end effects also are significant. There it can be noticed that, at first, the oil saturation increased and then decreased again. This can be interpreted as the accumulation of oil coming from the upper part, corresponding to the build-up of an oil bank, and followed by the production of this oil. The existence of the capillary retention zone at the bottom of the core suggests that only a very small amount of oil, if any, could be produced from that part.

Even after the core was isolated the in situ saturation measurements continued for one month and showed that the oil was still slowly accumulating at the outlet face of the core.

Three phase oil relative permeability

Three phase relative permeabilities may be deduced from the oil saturation profiles. Several analytical calculations have been proposed by authors. In a first attempt to ascertain the oil relative permeability during the gas gravity drainage, the method developed by Foulser et al.[4] was used. This method relies on two main assumptions ; the gas/oil capillary pressure can be neglected and the viscous forces are negligible with respect to the gravity forces. These conditions were fulfilled in the experiment since the gas/oil IFT was only 0.63 mN/m and the gravity number was Ng = 9 (>1). However as revealed by the in situ saturation measurements, the capillary end effects were significant at both ends and their influence on the Kro determination was not yet investigated. The calculation was applied to the very top of the core and gave consistent results. The Kro decreased from 10^{-3} to 10^{-5} as the oil saturation dropped from 25% to 10%.

NUMERICAL SIMULATION

The experiment was simulated using a generalized compositional simulator COMP4. The purpose was to validate a three phase relative permeability model. This validation was based on the match of experimental data. The main constraints to respect were the production curves as a function of pore volume injected, the differential pressure across the core and the in situ fluid saturation distributions.

The two phase relative permeabilities were put into the model as obtained from special core analysis. The up-scaling was made to reproduce the end-points measured on the long core. The drainage capillary pressure curves were also obtained from the SCAL study and up-scaled for the experimental conditions.

The long core was modeled by 21 grid cells, with two dead cells at each end, in the vertical direction. The rate of injection was imposed and the producer operated at a fixed pressure corresponding to the displacement pressure (230 bar). Good agreement was achieved for the secondary waterflood as illustrated in Figures 11 and 12. Irreducible water saturation distribution and residual oil saturation profile were used as input.

The initial conditions for the tertiary displacement simulation corresponded to those prevailing at the end of the waterflood. The main parameter for matching the gas gravity drainage was the three phase oil relative permeability. The rapid gas injection phase (40cm3/h) proved to be difficult to reproduce in the simulation because of the significant compression of the gas which occurred at the beginning of the injection. The volume of gas injected during this phase was however respected and the increase in pressure reproduced thanks to the reduction of the transmittivity between the injector well cell and the first cell of the modeled core. The low rate gas injection phase was simulated and the agreement between simulated and experimental results was obtained using the Stone 1 model for three phase oil relative permeability, as illustrated in Figures 11 and 13.

This procedure of validation, based on the simulation of a well-described experiment, seems to be an appropriate way to obtain reliable and consistent relative permeability model, which could eventually be used in field-scale predictive simulation with some confidence.

CONCLUSIONS

A tertiary gas gravity drainage experiment was performed in reservoir conditions in order to ascertain the dynamics of oil production at low oil saturation. Dual energy gamma-ray absorption measurement technique was used to follow the in situ fluid saturations.

1. The experiment was conducted on a reservoir water wet sandstone with a positive spreading coefficient for the fluids. In these conditions the gas gravity drainage proved to be very efficient.

2. Very low oil saturations were observed in the upper part of the core. However significant capillary end effects were in evidence, both on the outlet and the inlet face. In such a case, the in situ saturation monitoring was essential to correctly judge of the efficiency of the process.

3. The experiment was simulated with a generalized compositional simulator. Oil, water and gas production curves were matched and the in situ saturation profiles correctly reproduced. The agreement between simulated and experimental results was achieved using the Stone 1 model for three phase oil relative permeability. The validation of this model on this experiment supports its use for field scale predictive simulations.

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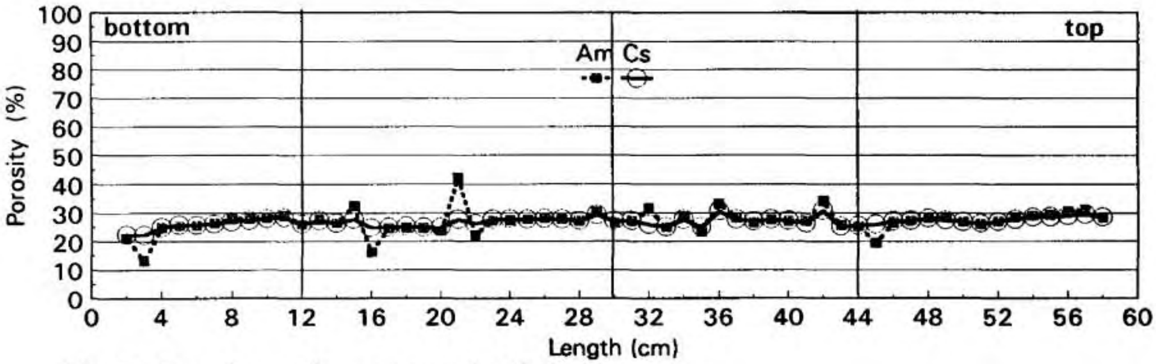

Fig. 2 : Porosity profiles measured with both sources

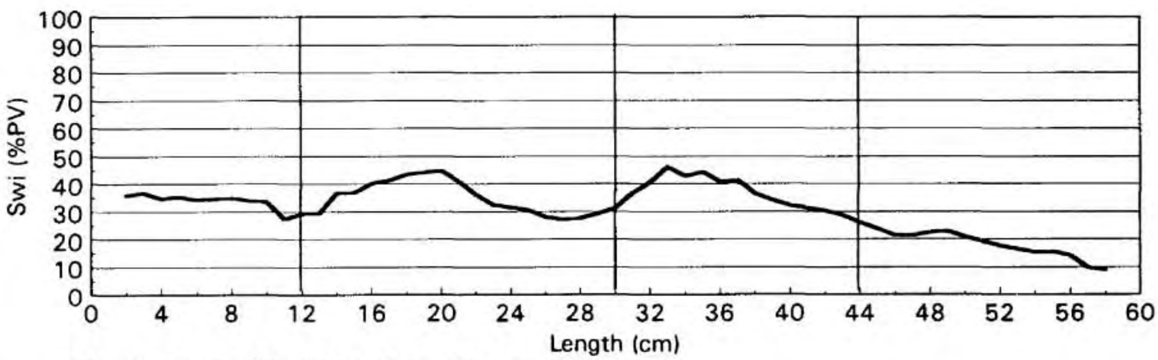

Fig. 3 : Irreducible Water Saturation profile

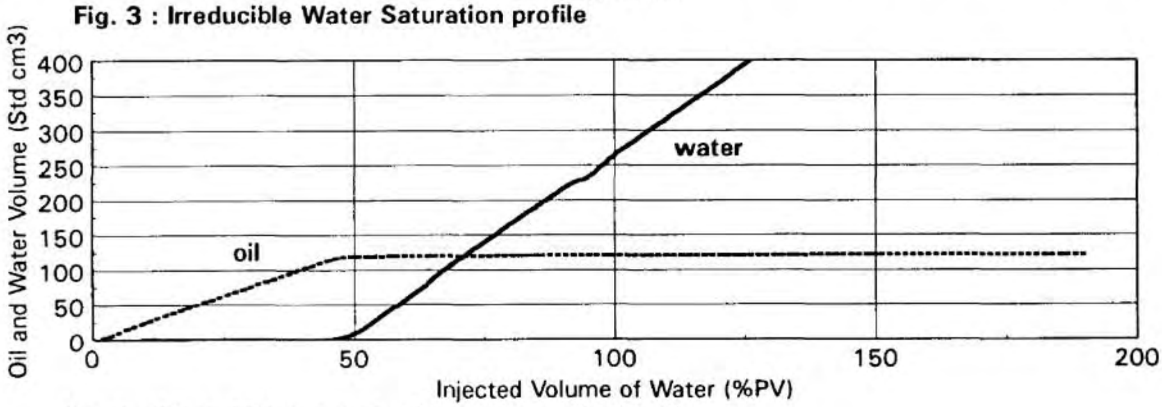

Fig. 4 : Oil and Water production during waterflooding

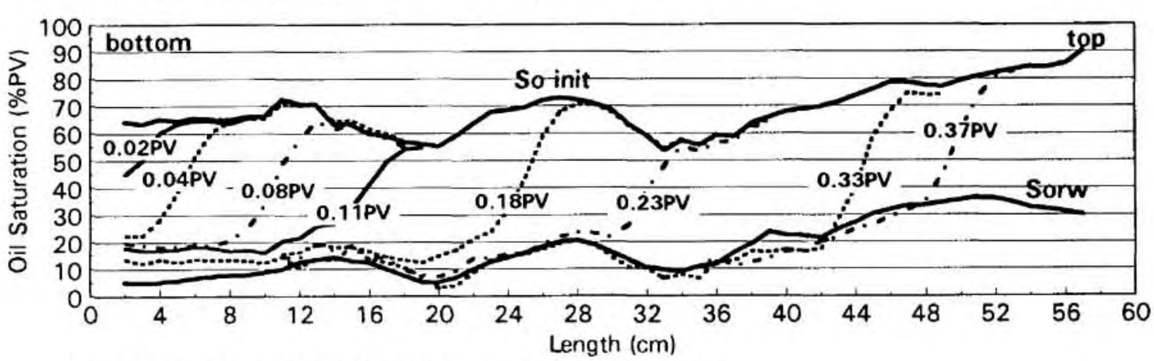

Fig. 5: Oil saturation distribution during waterflooding

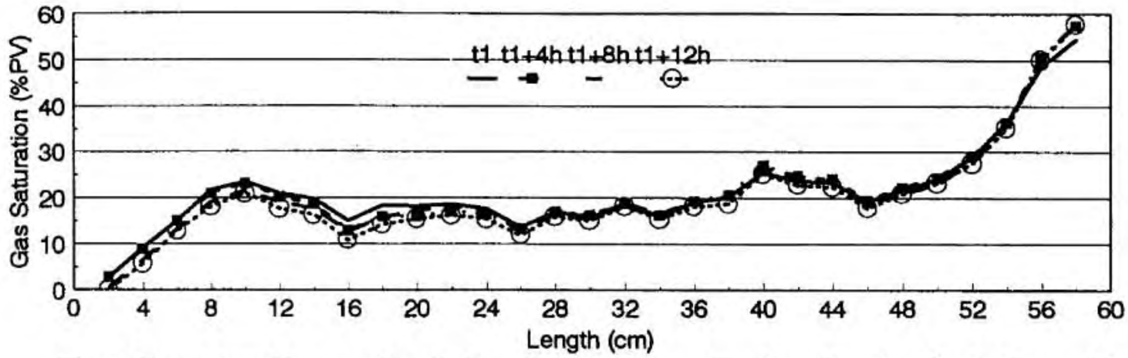

Fig. 6 :Gas saturation profiles during stand-by phase (Tertiary Gasflooding). The rapid gas injection was stopped at instant t1.

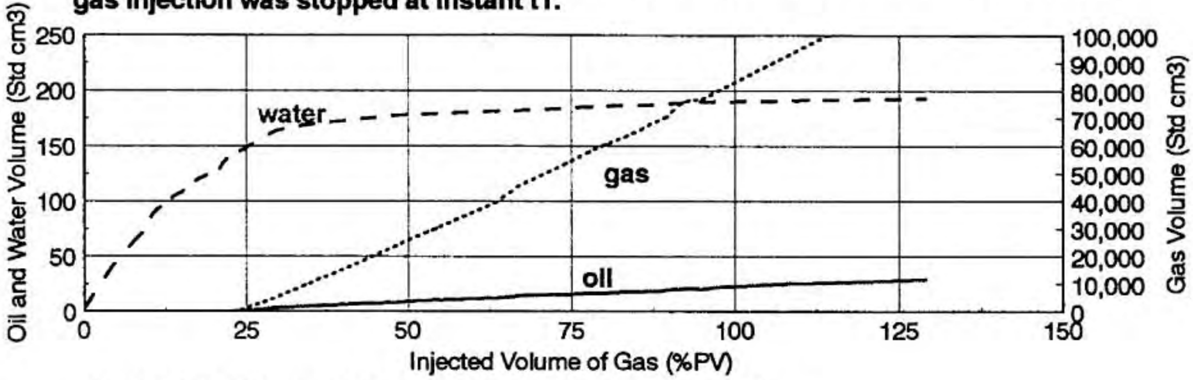

Fig. 7 : Oil, Water and Gas Production during gasflooding

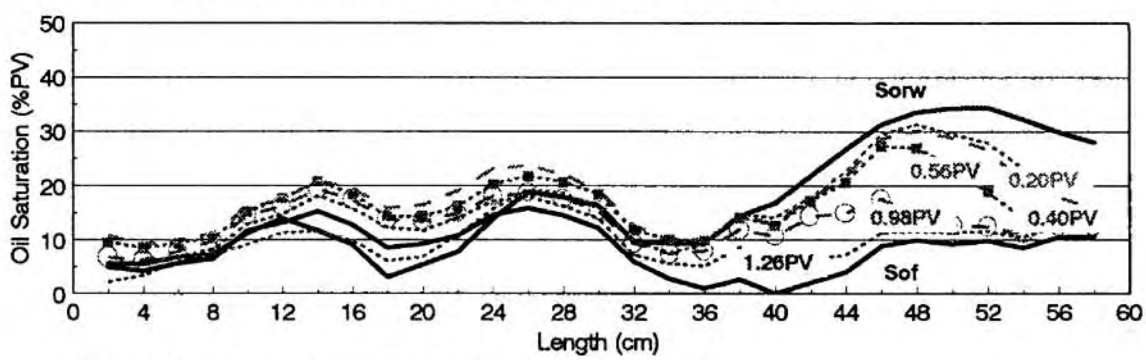

Fig. 8 : Oil saturation distribution during gasflooding

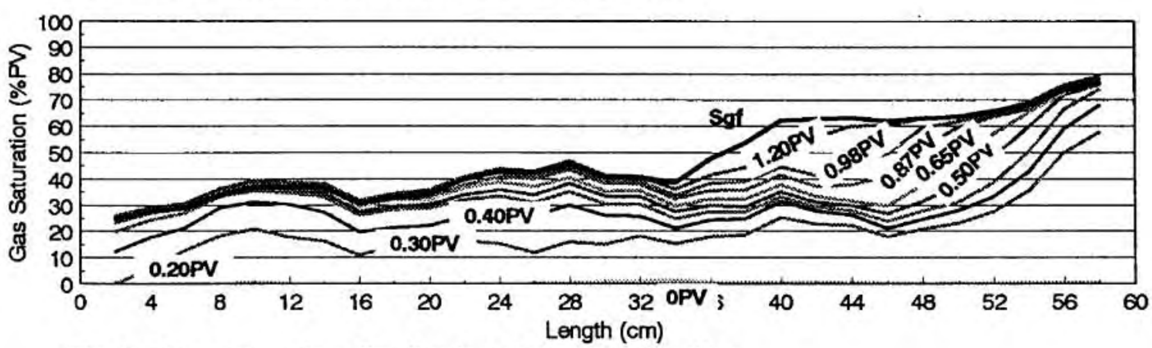

Fig. 9 : Gas saturation distribution during gasflooding

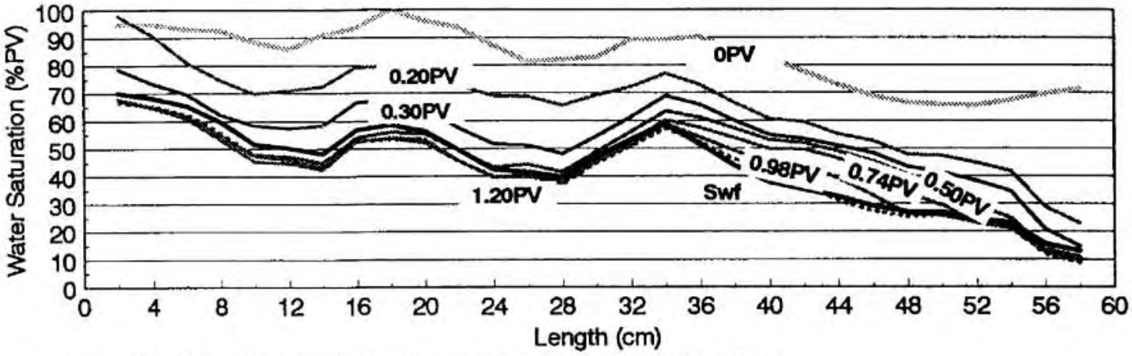

Fig. 10 : Water saturation distribution during gasflooding

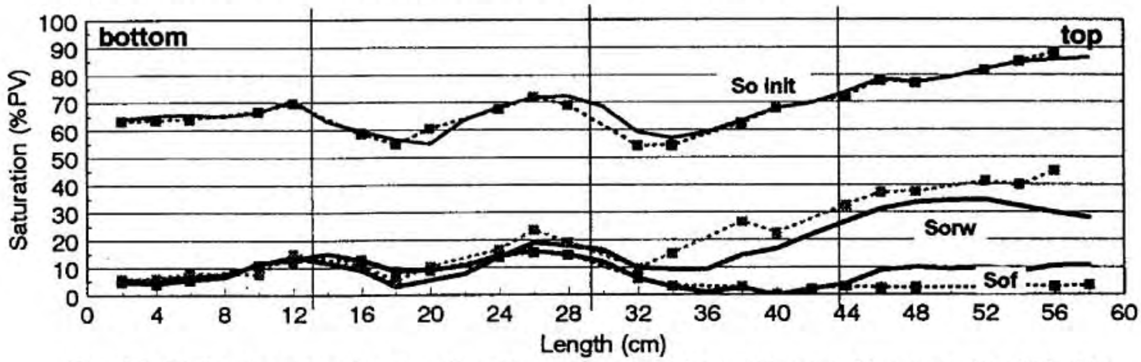

Fig. 11 : Main oil saturation profiles *(experimental in continuous line and simulated in dotted line)*

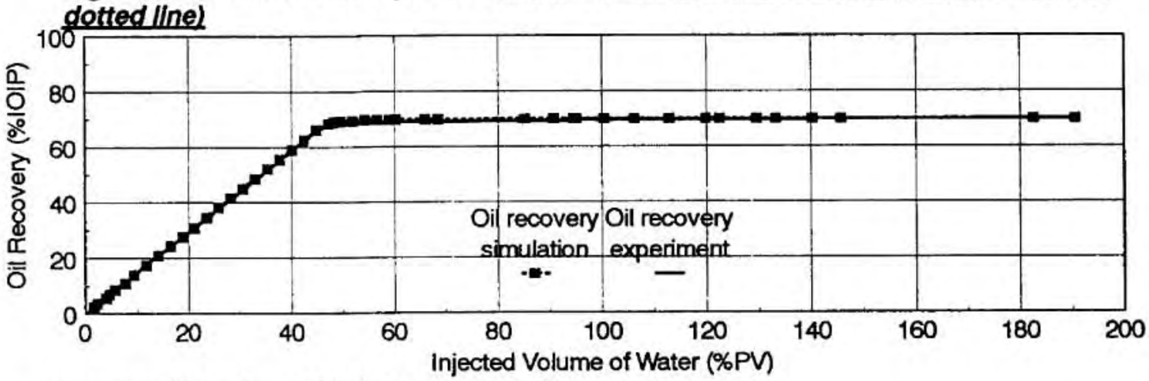

Fig. 12 : Waterflood Oil Recovery match

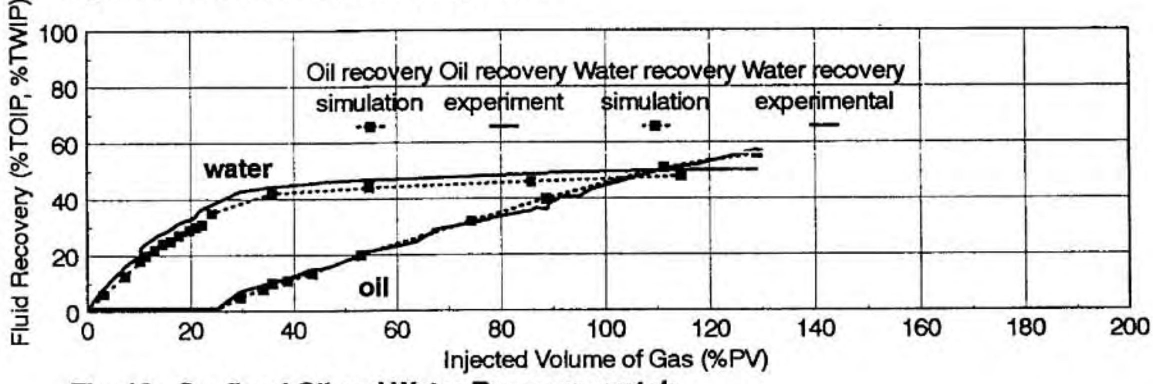

Fig. 13 : Gasflood Oil and Water Recovery match