HETEROGENEOUS SYSTEMS: AN INTEGRATED APPROACH BASED ON DIFFERENT IMAGING TECHNIQUES

G. Maddinelli*, A. Camanzi*, C. Carati* and A. Brancolini**
* Eniricerche S.p.A, S. Donato, Milan, Italy
** Agip S.p.A, S. Donato, Milan, Italy

Abstract
The study is based on the application of two different techniques: MRI and CT X-Ray. MRI is sensitive to hydrogen nuclei and reveals fluids distribution and therefore porosity, while X-Ray CT may give important details on rock matrix heterogeneity because of its sensitivity to the density of the medium.This type of analysis could be applied efficiently in a preliminary estimation of the cores, providing data to integrate successive localised microscopic examinations (SEM), which constitute an input for petrography. Both techniques provided complementary information on a submillimetrical scale of a Dolomite reservoir sample. The sample, saturated with water and oil, was analysed and successively flooded with deuterated water, which is MRI invisible. Images were taken after the waterflooding step and data analysed to evaluate macroscopic porosity connections. Significant changes in fluid distributions after the displacement, were observed. In a successive step, the petrographic analysis of thin sections of the sample allowed establishment of relations between the distribution of fluids and the peculiar porosity of this kind of rock.

INTRODUCTION

A better understanding of rock structure, pore space distribution and rock-fluid interaction in the reservoir, is strategic to design an efficient oil and gas recovery scheme. This requires a correct evaluation of porosity, fluid distribution and transport properties of the reservoir porous system, considering that pore space characteristics strongly influence entrapment of fluids. Reservoir performance is affected considerably by heterogeneities on several scales from large structural features to millimetric scale within the rock matrix. Carbonate reservoirs are generally highly heterogeneous systems typically characterised by a large presence of vugs and fractures which significantly influence the dynamic performance of the system (1-2) In this case, standard core analysis methods fail severely in petrophysical parameter evaluation (3). Measuring permeability, capillary pressure or even porosity on systems characterised by diffused irregularities would certainly results in misleading data. A different approach based on integration of novel high tech methods is needed. X-Ray CT and Magnetic Resonance Imaging (MRI) are non destructive and proven tools for studying the influence of small scale geological heterogeneities on fluid flow and trapping. Moreover, its application is useful in understanding the porosity distribution and the fracture networks which are essential to petrophysical analysis. While CT is more dedicated to distinguishing rock matrix features such as fractures and the effect of pressure on them (4,5,6), MRI can investigate directly spatial distribution of fluids. In this study CT and MRI were used to investigate pore space aspects compared to fluid preferential distribution. This kind of information could help understanding of dynamic properties of the medium.

CORE TREATMENTS

A sample cored in a dolomite reservoir (10 cm in diameter and 11.7 cm in length) was dried for 14h at 60° C and subsequently fully saturated with oil (Soltrol 130). Figure 1 shows photographic images of the crude sample. In a second step the core was flooded with 3 PV (250 cc) of deuterated water (99.8%) at a rate of 1 cc/min. A plug (1" x 2") was drilled at the top edge of the previous sample. It was thoroughly cleaned by the Soxhlet extraction with toluene and dried for 48h at 110° C, then saturated with Soltrol 130 and subjected to MRI and X-ray CT studies.

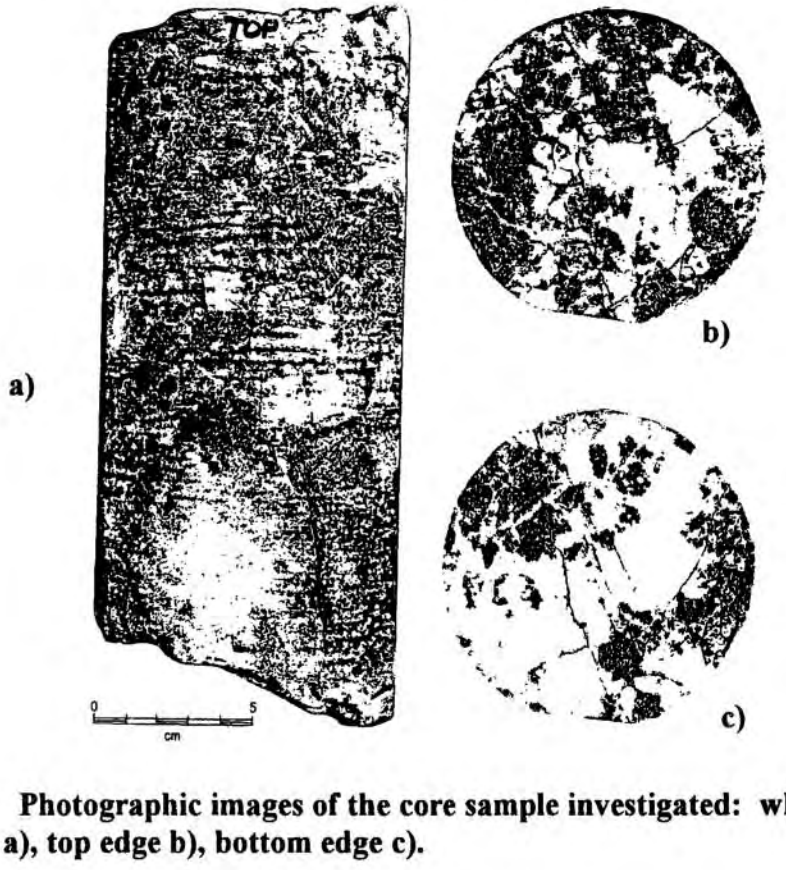


FIGURE 1 Photographic images of the core sample investigated: whole sample a), top edge b), bottom edge c).

MRI AND CT STUDY

The core was analysed by MRI at every step of the treatment using a SISCO instrument equipped with a 2 T, 31 cm bore magnet. Images taken are typically 256 x 256 pixels, characterised by a 2 mm thickness and a planar resolution comprised between 0.2 and 0.5 mm. A number of 10 transverse (perpendicular to the main axis of the sample) and 10 longitudinal images were acquired at each step of sample treatment (resolution of 0.5 mm in the plane and slice thickness of 2 mm) separated by approximately 1 cm. This set of images allows a 3D reconstruction of the sample architecture. Image results will be discussed in the following paragraph.

X-Ray CT imaging was performed using a Magic-Intercontrole instrument on a dried plug (1" x 2") cored at the top edge of the main sample. MRI tool is particularly useful in this applications, because of its sensitivity to hydrogen nuclei present largely in the fluids. After drying and oil saturation (1st step), the sample revealed a consistent presence of water. This is clearly shown in the ^1H NMR spectrum of figure 2, where the peaks of water (5 ppm) and oil (1.5 ppm) are sufficiently resolved due to the low magnetic susceptibility of the dolomite rock.

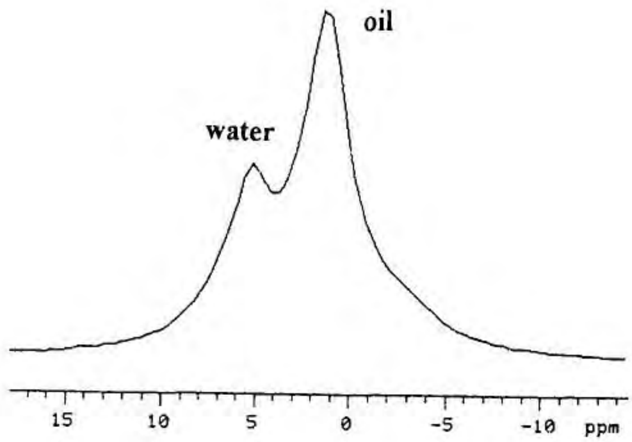


FIGURE 2 ^1H NMR spectrum acquired on the core saturated with oil (signal at 1.5 ppm), showing the presence of residual water (5 ppm).

The residual water (40 %) measured by NMR spectroscopy indicates the inefficiency of the drying procedure adopted. Flow treatment with deuterated water (2nd step) reduced the percentage of water to 30 %. This may be determined both by partial mobility and exchange of water with D_2O due to diffusion processes. Particularly useful for petrophysical analysis of heterogeneous samples is the evaluation of porosity along the core. A standard spin-echo sequence whithout slice selection, allowed detection of signal from the whole object which is critical for quantitative measurements. The above technique was applied to get distribution of fluids along the core as shown in figure 3.

The profile of figure 3b, obtained on the first step shows the non uniform distribution of fluids determined by the nature of the rock (visible in the NMR image of figure 3a). By means of a standard reference this profile allows estimation of total porosity (11%). This value differs significantly from that obtained by conventional laboratory tests (7.15 %). The profile (figure 3c) obtained after deuterated water flooding (second step) reveals decrease of porosity value to 6 %. The apparent variation in porosity after D_2O treatment (D_2O is NMR invisible at the frequency applied) indicates either the amount of fluids displaced either the exchange of water with D_2O. The content of water retained by the rock matrix (1.5 p.u.) may be associated to water not accessible to D_2O (intracrystalline porosity). Following investigation was devoted to correlate porosity data with fluids distribution and petrographical features.

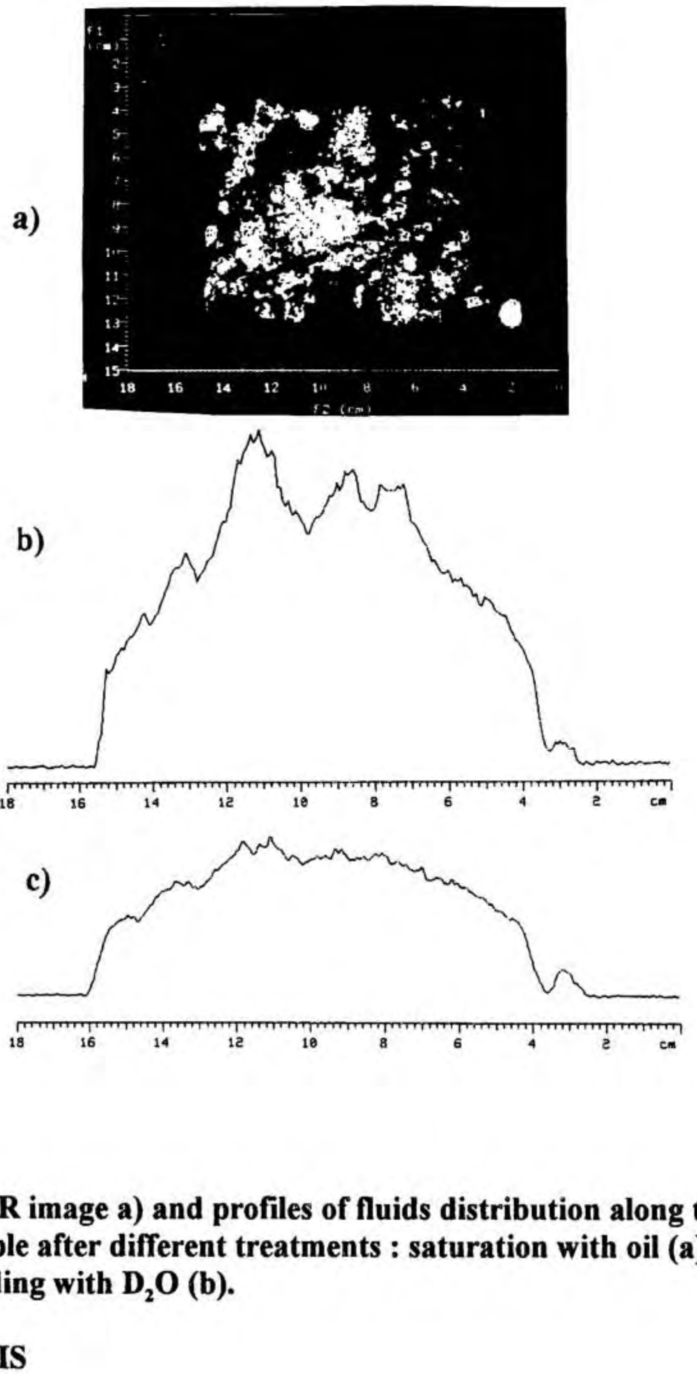


FIGURE 3 **NMR image a) and profiles of fluids distribution along the core sample after different treatments : saturation with oil (a) and flooding with D_2O (b).**

IMAGE ANALYSIS

From lithological studies of the rock samples, different typologies of porous networks were identified corresponding to three different models of porosity distribution: vuggy, mottled microvuggy, fine diffused microvuggy.
However, for prediction of an oil displacement mechanism in an heterogeneous system, is useful to associate pore space aspects to fluid distribution. The rock core under investigation (figure 1), which appears highly structured, is a pink dolomitic breccia, quite recrystallised, with a prevalent mottled microvuggy porosity in the clasts, and large spread vugs, (larger than 2 mm). Several fractures are present and clearly visible

in the sample, some of them longitudinally oriented along the core. The above fractures could play a significant role in oil production.
Four representative transverse images (MRI), relative to the first step of the treatment, are shown in figure 4. Images are characterised by 63 levels of gray related to the spectroscopic density of fluids. The brightest areas indicate a high concentration of oil and water and therefore very porous regions. The darkest areas reveal instead the complete absence of liquids and indicate non porous zones which may typically be cemented regions or fractured. The intermediate gray areas suggest a diffused microporosity region. After image acquisition, the sample was cut in correspondence with the transverse images in order to compare image data with visual inspection.

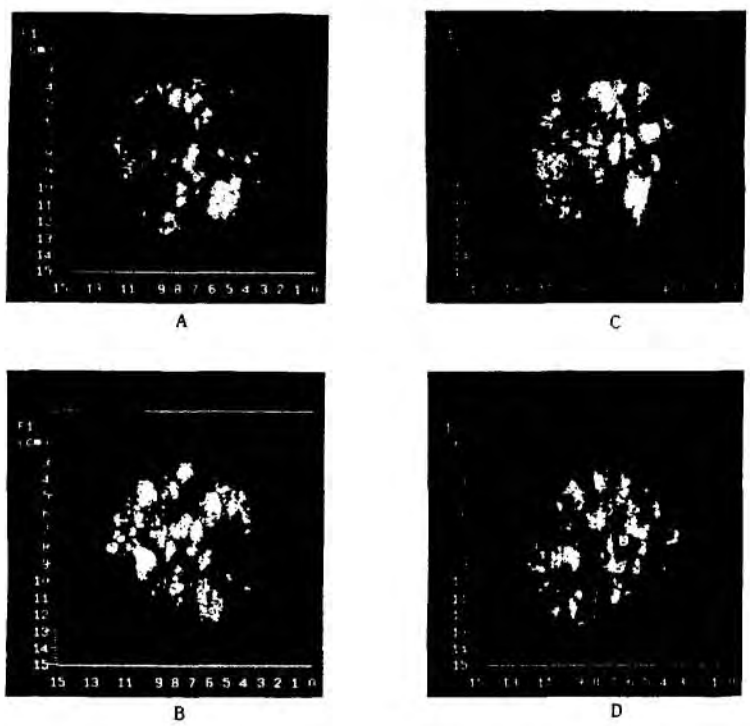


FIGURE 4 Transverse NMR images (256x256 pixels) corresponding to different positions along the core.

Figure 5 shows the selected image C (5b) compared to the photo taken of the corresponding section cut at the end of the whole experiment (5a). This sample shows a certain kind of porosity indicated as "mottled microvuggy porosity". This is formed by intercrystalline porosity developed in sucrosic dolomite clasts immerged in a non porous matrix. Within clasts the intercrystalline porosity increases in some zones resulting in larger vugs. Fig. 6 shows schematically the different types of porosity present in the chosen section. A few vugs with dimensions larger than 2 mm size are also present in the matrix (vuggy porosity). By comparison with the rock, a fracture filled by fine material was also determined. MRI could not efficiently reveal open fissures and this is probably due to the relatively low resolution adopted which avoid determination of details lower 500 μm or to drainage phenomena. Figure 5c shows an image taken on section C, flooded with D_2O (2nd step). Analysis of images 5b and 5c indicates a decrease in signal from vuggy to microvuggy regions, consisting with preferential fluid displacement from these areas.

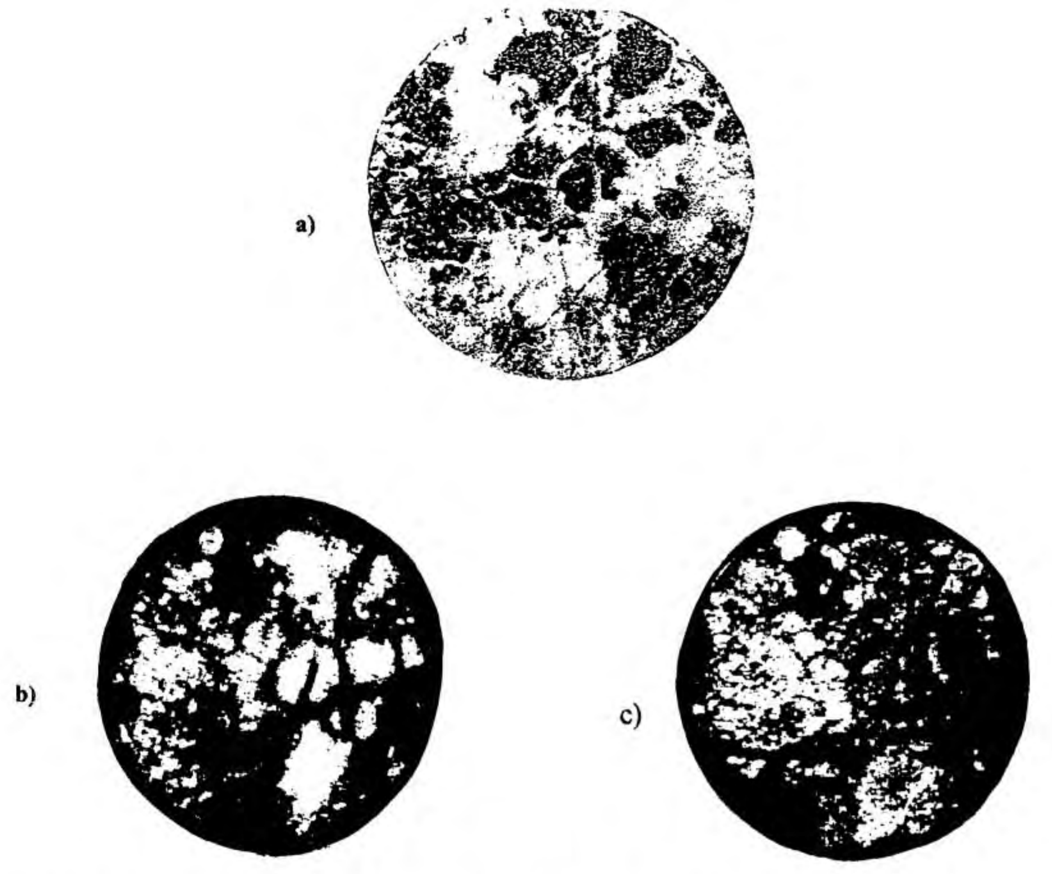
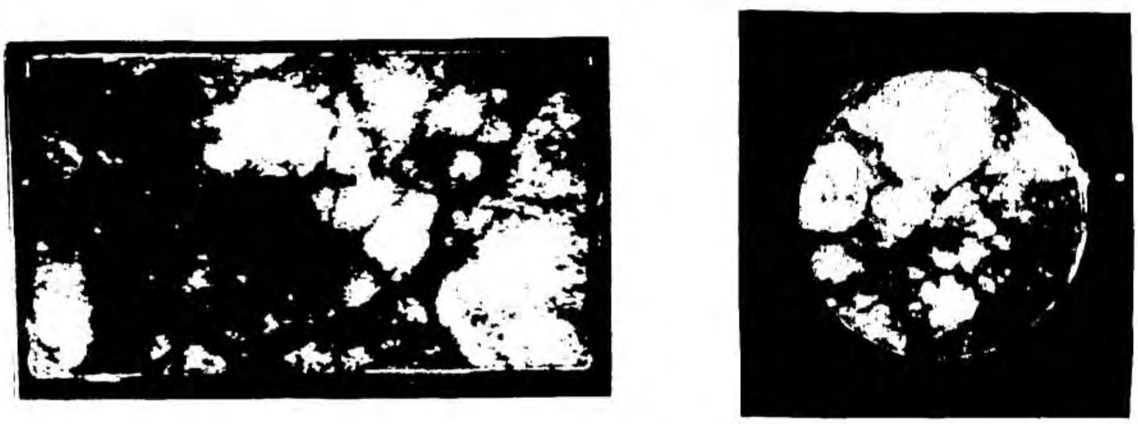


FIGURE 5 Photograph of a thin section of the core (a) compared to corresponding NMR images acquired after saturation with oil (b) and flooding with D_2O (c).

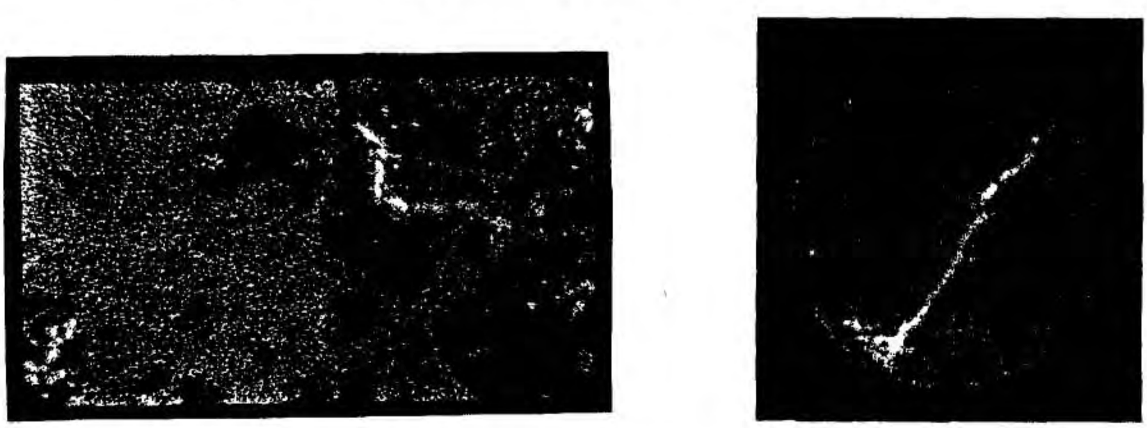
FIGURE 6 Distribution of rock matrix features obtained by petrographical analysis of a thin section (a) and the corresponding NMR image(b).

MICROVUGGY REGIONS

Strong water retention observed by spectroscopic measurements suggested the presence of porous regions within water is strongly trapped. To confirm this phenomenon, further experimental work was performed on a plug drilled close to the main sample. The choice of a smaller sample was determined by the necessity to increase drying conditions, and to improve resolution. The sample was dried at 110° C for 48 h and then saturated with oil. Nevertheless, a significative amount of water was detected. MRI revealed a highly heterogeneous distribution of fluids in the plug (figure 7a) visible as brightest areas, which perfectly correspond to the darkest areas, due to low density regions, in the CT image (figure 7b). The sample presented a fracture which does not appear filled with fluid according to the longitutidal and transverse NMR images of figure 7a. The details are confirmed by analogous CT images obtained on the same sections, which clearly show the presence of high density material cementing the fracture. This example highlights the powerful integration of the two techniques.



a) MRI (sample saturated with oil with residual water)



b) X Ray CT (dried sample)

FIGURE 7 Longitudinal and transverse images taken on sections of a plug drilled at the top edge of the core: a) NMR images ; b) corresponding X-Ray CT images (the brightest areas indicate high density regions)

A specific tool of MRI is the capability to distinguish different fluids and their interaction with the rock matrix, by means of chemical shift or relaxation times differences. Applying an inversion-recovery type sequence, which allows discrimination of spin-lattice relaxation time (T_1), selective oil (figure 8a) and water (figure 8b) sensitive images were obtained. Oil shows the tendency to fill large vugs, while irriducible water seems to distribute preferentially in the wide spread microporous areas. Image 8a and 8b suggested that the system constitues a large microporous matrix within which water is strongly trapped, and vugs of different size probably connected by small fractures. Only the latter type of porosity could be considered useful for oil entrapment and flow. A more detailed description in term of fluids and pore size distribution is available by comparing data from SEM and NMR relaxation times analysis as shown in figure 9. Figure 9a-b shows results of SEM analysis on a similar zone of a dolomite sample with analogous porosity type. The image 9a and relative histogram 9b clearly show larger pores (100-250 μm) immerged in a fine diffused microporosity. SEM results can be usefully compared to T_1 spin-lattice relaxation times measured on the fully water saturated sample. According to theory (7), T_1 is proportional to pore size. T_1 distribution (figure 9c) gives a picture of fluid distribution in three wide ranges of pore size, which could be usefully compared to SEM analysis results and previous observations on porosity classes.

a

b

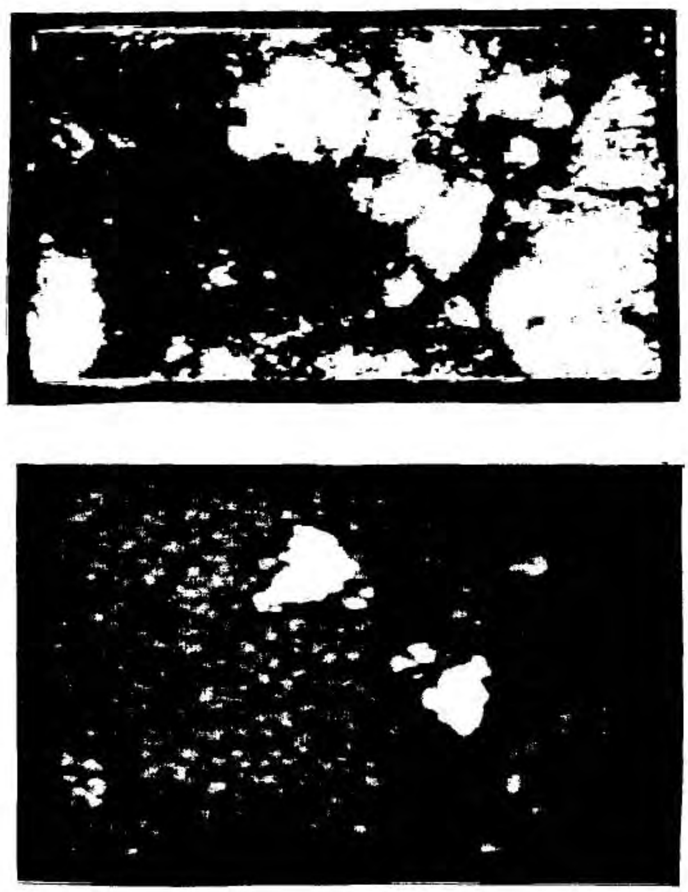
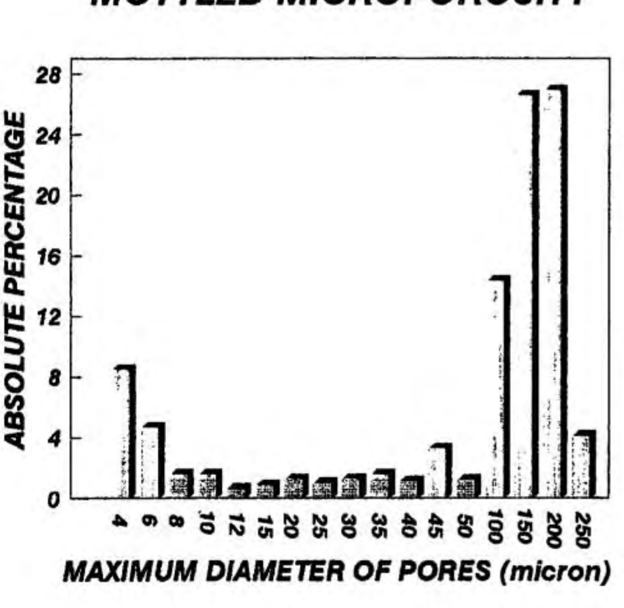


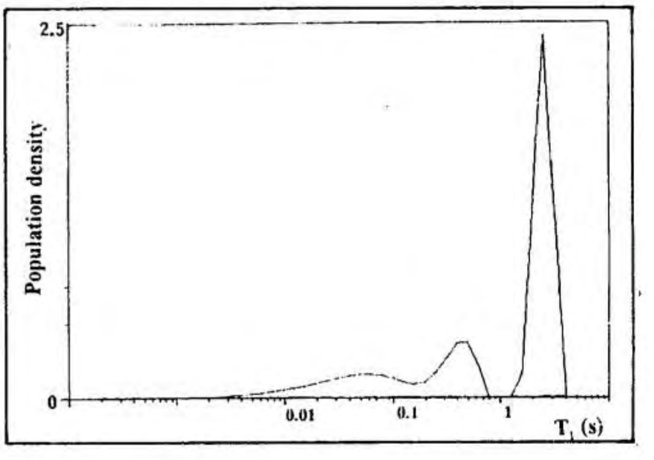
FIGURE 8 NMR images sensitive to oil (a) and water (b) distribution.

MAGNIFICATION IMAGE (100 X)
MEAN POROSITY : 10,84%

a)



b)



c)

FIGURE 9 SEM and T_1 relaxation analysis on analogous dolomite sample : a) SEM image showing the microporosity region; b) histogram showing pore size distribution obtained by image analysis; c) T_1 distribution measured on the sample saturated with water.

CONCLUSIONS

Imaging techniques are powerful tools for investigating heterogeneous media such as vuggy and fractured carbonates.
MRI provided a description of fluids location and of pore space characteristics for the dolomite core sample, which consists mainly of mottled microvuggy areas alternated by larger vugs.
Water was detected even after the most severe drying procedure (1"x 2" plug).
MRI revealed a fine microporosity within which water is strongly trapped. This non-effective microporosity consists of pores with diameter of a few microns, as revealed by SEM analysis. Oil was distributed in microvuggy to vuggy regions.
X-Ray CT efficently determined density heterogeneities (i.d. a thin cemented fracture), not revealed by MRI.
Pore space aspects combined with changes of fluids distribution observed by a flooding procedure with deuterated water on the oil saturated sample, can provide useful information on mobility :
- portion of oil occupying larger vugs is prefentially swept;
- oil probably move through fissures and fractures from one vuggy zone to another.

Imaging techniques are able to integrate and check routine laboratory tests, since they give information on fluid distribution, rock matrix characteristics, total and effective porosity and residual oil saturation.

ACKOWLEDGMENTS

A. Bersani and P. Ronchi, Agip S.p.A, are greatfully acknowledged for their important contribution to petrographical analysis of data. The authors wish to thank the management of Agip S.p,A and Eniricerche S.p.A for sponsoring and permission to publish data. Intercontrole, Grenoble is also acknowledged for access at the CT scanner.

REFERENCES

1) Hove, A., Ringen, J.K., Read, P.A., "Visualisation of Laboratory Corefloods with the Aid of Computerized Tomography of X-Rays", SPE 13654 presented at SPE California Regional Meeting, Bakersfield, CA, Mar. 27-29, 1985;
2) Saidi, A.M.,"Reservoir Engineering of Fractured Reservoirs", 1987, Total Ed. Press;
3) Sprunt, E.S.; "Arun Core Analysis: Special Procedures for Vuggy Carbonates", The Log Analyst, Sep-Oct1989, p. 353-362 ;
4) Hagiwara ,T., Nanba, T., "Generation of Proximity Function for Naturally Fractured Reservoir Simulator Using X-ray CT Scanner System", presented at the Eleventh Workshop of the IEA, Collaborative Project on EOR, Paris, Oct. 1990;
5) Hagiwara, T., Nanba, T., Matsumoto, K., "Application of X-ray CT Scanner System to The Evaluation of Naturally Fractured Reservoirs", presented at the 12th Workshop of the IEA Collaborative Project on EOR, Bath, Oct 1991;
6) Bergosh, J.L., Lord, G.D., "New Development of Analysis of Cores from Naturally Fractured Reservoirs", SPE 16805, 1987, An. Tec. Exibition Proceedings, v.omega, Form. Eval.and Reservoir Geology SPE, p. 563-570.
7) Davies, S., Paker, K.J., "Pore size distribution from NMR spin-lattice relaxation measurements of fluid saturated porous solids. I Theory and Simulation". J. Appl. Phys., 1990, 67, No. 6 March 15.