STRATEGY TO REDUCE UNCERTAINTIES IN CORE ANALYSIS PROGRAMS THROUGH THE USE OF MAGNETIC RESONANCE IMAGING: A NEW PERSPECTIVE

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ABSTRACT

Techniques that facilitate the measurement of the spatial distribution of pore structure characteristics, particularly if made at the same scale (i.e. over the same representative volume) as other physical measurements, provide crucial insights regarding the interpretation of core analysis data. Of the available techniques, Nuclear Magnetic Resonance (NMR) Imaging or Magnetic Resonance Imaging (MRI) provides data that best address this requirement for carbonates. This paper examines why this is the case, the limitations of the technology and common mistakes that can be made by operators when seeking to acquire high quality MRI data.

We have found that a real advantage to the MRI technique is that it is non-destructive and it is carried out on the same sample volume that the core analysis tests are carried out. Carbonates are ideal candidates for MRI screening because of their low magnetic susceptibility. Due to their complex pore structures, thin-section MRI methods must be used to avoid the “full moon” effect that has been reported by other operators due to volume averaging the entire core plug. Volume selective magnetic resonance images of carbonate samples reveal the spatial distribution of micro, matrix and vug porosity. Multiple echo time imaging can identify micro-porosity regions of the sample and an estimate of the vug porosity can be made from the binary segmentation of long echo time images. Fracture detection and characterization (fluid filled or mineralised / mud damaged) can be carried out quickly and easily. The low magnetic susceptibility of carbonates also permits the acquisition of relaxation information at high field. Low field NMR relaxation data suffers from diffusion and low relaxivity effects that can make prediction of pore space properties difficult. High field NMR data more accurately reflects the true nature of pore space, and can be used to improve the manner in which low field NMR and electrical resistivity logging data are interpreted. The role that MRI can play in displacement experiments is also examined. By monitoring the displacement of the brine phase by the oil phase, flow anomalies can be detected *prior* to the aging step, resulting in a significant savings of time and money. This directly addresses the question, “Does the core reflect the interval of interest?” and reduces the uncertainties present in each and every relative permeability test carried out today.

INTRODUCTION

A considerable amount of literature has been published about the application of Magnetic Resonance Imaging (MRI) to porous media samples. Articles have discussed the static imaging of fluids imbibed into porous materials [1-4], the monitoring of fluid displacement processes [5-8], the application of the technique to enhanced oil recovery processes [9-12], and the applicability of the technique to the study of formation damage [13-15]. In a number of cases, the applicability of the MRI pulse sequences is limited, and a paper that discusses the overall suitability of the MRI technique to reduce uncertainty in core analysis measurements has not been published.

The intent of this paper is to summarize the relevance of the MRI technique to reservoir core samples utilizing the technical knowledge we have gained over the past 11 years. The goal is to demonstrate the utility of the technique, outline the technical difficulties, and outline solutions with regards to its implementation in core analysis programs.

EXPERIMENTAL DETAILS

The reader should note that the term Nuclear Magnetic Resonance (NMR) is the general term used to describe magnetic resonance technology, and there are three main forms of the technique which are used by the petroleum industry: (i) NMR Imaging or MRI is used to determine the spatial distribution of the pore space or distribution of fluids, (ii) NMR relaxation analysis is used to probe the pore space dimensions of porous media or reservoir rocks either in the laboratory or through the use of logging tools and (iii) NMR spectroscopy is used to determine the structure of compounds. As such, spectroscopy applications are not discussed in this paper. However, we have found that the NMR spectrum of a brine filled rock sample indicates the magnetic susceptibility of the sample. The NMR line-width, which is the width of the NMR spectral line at the half-height, is used as a measurement of this interaction.

The instrumentation used for imaging and relaxation data in this paper consists of a horizontal bore Bruker Spectrospin Biospec BC 24/30 imaging system operating at a field strength of 2.35 Tesla, in which the frequency for hydrogen detection is 100 MHz. The NMR magnet is enclosed in a copper shielded room (faraday cage), which eliminates a variety of noise sources and boosts the signal to noise ratio in the images. We have also found that adjusting the homogeneity of the main magnet field (shimming) is of the utmost importance for high quality images.

Non-magnetic core holders and a variable temperature unit have been designed to facilitate core flood experiments at elevated temperatures and pressures (100° C and an overburden pressure of 2000 psi for core plug sized samples). A Bruker X-32 computer system is used for data acquisition and has been interfaced with desktop personal computers. The data is initially stored in 32-bit integer format and is converted to floating point to facilitate image analysis. An image analysis software program has been written for use on PC’s, which permits for comparison of core plug samples and the examination of displacement data.

The MRI technique does not detect the rock space nor non-hydrogen containing gases (i.e. nitrogen or carbon dioxide) and is only responsive to fluid imbibed into the pore space of the sample. The Bruker instrumentation can examine samples up to 10 cm in diameter, but we have found that the best performance arises when examining core plug samples (4 cm in diameter by 10 cm maximum length). For pore space characterisation work, the sample must be fully saturated with brine, oil, or a combination of the two fluids. MRI is a non-destructive technique and the core samples examined can be used in routine or special core analysis studies afterwards. Samples cannot be scanned if contained in metal containers or in aluminium foil / wax.

To compare core plug sample images, it is necessary to compensate for receiver gain and signal averaging. A straightforward algorithm was established, permitting the comparison of core plug samples. The imaging sequence used is generally a 3d phase-phase encoded volume selective spin-echo sequence that permits for matrices of 128x128x16. The number of slices can be increased from 16 to 64 with a concomitant increase in the scanning time. The images can be acquired directly from the sample in either a radial or lengthwise direction. The echo time is on the order of 5 ms and the relaxation delay commonly used for imaging data is 1 second. No attempt was made to eliminate T_2 relaxation effects from the images. We believe that the images benefit from spin-spin relaxation effects in that the images become porosity type weighted.

"Images" can also be acquired which are one-dimensional saturation profiles. These have the advantage that they can be acquired quickly, allowing for the monitoring of fluid displacement processes. The relaxation delay used for the saturation profile data was 20 seconds to permit for removal of spin-lattice effects. No attempt was made to remove spin-spin relaxation effects from the profile data. Although not required for monitoring the core plugs for flow artefacts, MRI profiles were found to be quantitative during standard waterflood procedures. In addition, we have found by monitoring the relaxation characteristics of the oil phase throughout the entire relative permeability experiment that the oil T_2 distribution does not appear to change, explaining why the gravimetric results agree with the MRI results.

RESULTS AND DISCUSSION

Imaging Of The Pore Space Using a Single Fluid Phase – Screening

One of the first ways in which the MRI technique can be applied to a core analysis program is in the screening of samples. Simply put, core samples are a valuable commodity and some assurance needs to be made that the samples are "representative" and reflect the properties of the interval of interest. From this perspective, the scanning of samples to detect heterogeneities before carrying out special core analysis programs should be of the utmost importance.

From an NMR perspective, for the spatial characterization of the pore space or core "screening", the sample must be saturated with fluid. This means that imaging full diameter core as received from the field is not normally carried out because the reservoir fluids have been expelled and the client does not usually desire re-saturation of the full diameter sample. This means that the integration of the MRI technique into the core analysis program is carried out at the core plug stage, after appropriate cleaning and saturation with fluid.

Although a number of papers have reported the successful application of MRI to observe the pore space in reservoir rocks, there are a number of technical considerations that come into play. First, and foremost, it is important to consider the mineralogy of the sample. Sandstone reservoir rock often has a high magnetic susceptibility due to the presence of iron mineralogy. This results in images that are blurred and combined with the increased transverse relaxation induced by these internal magnetic field gradients, there is a significant problem getting an image from iron rich samples. Samples that contain hematite and siderite are particularly difficult, while samples that contain pyrite exhibit no problems. Problem samples can be easily identified by measuring the NMR line-width. Samples which give rise to blurred images, have large linewidths (> 2000 Hz) while the majority of carbonate samples have NMR linewidths less than 300 Hz. This means that carbonate samples are a clear choice for the MRI technique.

Secondly, a number of papers have used “full volume” imaging (similar to that of a bulk x-ray, where the entire sample volume is projected into a two-dimensional image) to carry out screening studies. This technique is appropriate and time efficient for the majority of sandstone samples that typically have laminations that run the entire length of the sample (Figure 1). Carbonates, due to the depositional history and the post depositional processes, often have complex pore structures where full volume imaging results in what is colloquially known as the “full moon effect.” In other words, if you take two very different carbonate samples and image them without volume selection in a radial fashion, they will both look featureless (like a “full moon”) because of volume averaging of the pore space along the length of the core plug (Figure 2).

Instead, the proper implementation of the MRI technique is to acquire “slice selective” images, where the thickness of the slices is on the order of 1-2 mm (Figures 3,4). For a typical core plug, 64 radial slices or 16 lengthwise slices will reveal highly detailed pore space information, similar to a thin section microscope slide (not at the same resolution) but in a non-destructive way. In fact, one of the major advantages of the MRI technique is that the images are acquired on the same sample volume in which the core analysis will be carried out. This eliminates the problem that thin section microscopy has in which the thin section examined might not (and many cases does not in carbonate rocks) represent the sample due to variations in the pore space along the length of the sample. Also, the MRI can reveal these spatial variations, sometimes referred to as heterogeneities very effectively.

The MRI technique has a number of advantages in carbonate rock over its competition, X-Ray CT: (i) It does not suffer from beam hardening artefacts and penetration of the entire sample is uniform. (ii) It is sensitive to the fluids contained in the rock, and does not obtain the pore space though image subtraction processes. (iii) MRI acquires the data for lengthwise images directly, without the need of first acquiring radial images and then producing a lengthwise image by computational methods. We have found by comparison with a second-generation X-Ray CT imager (Figure 5) that the lengthwise images obtained by MRI reveal significantly more pore space detail (Figure 6). (iv) The number of "detectors" is programmable with the only penalty being echo time and total acquisition time. Using imaging matrices on the order of 128x128 give rise to excellent pore space resolution (in-plane resolution of 300 μm). (v) The NMR images are modified by spin-spin relaxation effects, which are seen as detrimental by some authors. However, we have observed that if two volume elements in a carbonate sample have the same "porosity" (say 10%) but different pore structures, (for example, in one volume element there are vugs, but in the other there is micro-porosity) that the X-ray CT, which is based on density differences will have difficulty seeing a distinction because the porosity and thus the density is the same, whereas the NMR image will show substantial variation due to the pore size differences and the corresponding relaxation behaviour differences of the pores in the two volume elements. For screening purposes, a technique that is sensitive to the porosity types is better than a technique that is sensitive to only porosity differences. (vi) The MRI sequence can be modified to acquire "long echo time" images in which the signal from the matrix has decayed and only signal from the long T_2 vugs remains. Using this technology, vug selective images can be acquired (Figures 7,8).

Having suggested in the previous paragraph that NMR images of carbonate reservoir rock are "relaxation weighted," a number of authors have produced NMR images of samples using a spin sequence that creates "T_1 maps" of the samples, in which the longitudinal relaxation is compensated. In some cases, using this technology they have created full volume porosity maps of the sample. What the authors have overlooked is that these images are still not corrected for spin-spin relaxation effects and are possibly not true porosity maps. Furthermore, the production of such images is an immensely time consuming process, requiring on the order of 1 – 2 days per sample, and for core analysis projects, this is prohibitively expensive. In addition, since the porosity distribution changes with the volume of rock sampled, what do these porosity maps mean and how can they be used? We have found that the straightforward implementation of a spin-echo imaging sequence with the shortest possible echo time and using phase encoded slice selective methods to acquire thin slice ("thin section") NMR images reveals important details about the spatial distribution of the pore space and is more important than producing relaxation free images.

Since relaxation-free quantitative images are time consuming and very difficult to obtain, this begs the question, "What information does NMR images reveal that is of use to the core analyst?" There are three important aspects of the pore space which are revealed by the MRI technique: (i) It detects the presence of fractures, and more importantly indicates whether they are fluid filled, mud damaged or mineralised (Figures 9,10). In other words, MRI helps determine whether or not core plug flow processes will have contribution to the flow from fractures, which has important ramifications for relative permeability and other core tests. Fractures which are fluid filled and contribute to flow have high signal intensity even in the presence of matrix porosity, while fractures which are mineralised or mud filled have no signal intensity and are black in the NMR images. (ii) It detects the presence of vug porosity. Using the thin section and the long echo time NMR methods together, an estimate of the vug porosity can be made using binary segmentation of the images (Figure 11). The signal from voxels (volume element) containing vugs in the thin section images is orders of magnitude higher than the signal from voxels that do not contain vugs and permits for easy segmentation. (iii) It detects spatial "discontinuities." The pore space in carbonate rocks is almost always heterogeneous and this does not always reflect flow heterogeneities. However, a number of samples may have wildly different pore structures inside the sample that cannot be detected by inspection of the sample by a geologist, and these features will adversely affect the core analyses that are carried out. This is particularly dire when the results of that core plug are scaled up to represent a zone in the reservoir.

Relaxation Data

High field NMR relaxation data has always been looked upon as objectionable because of the induced magnetic susceptibility effects, which increase with field strength. The argument is that significant portions of the pore space are eliminated from the T_2 relaxation distribution because they are too short to be captured by spin-echo relaxation sequences. In the case of sandstones this is understandable and true for a number of samples, however the low magnetic susceptibility of carbonates permits the acquisition of high field relaxation data.

In carbonates, as a result of the low surface relaxivity and diffusion averaging effects, the low field NMR data can appear relatively insensitive to the pore space. This is illustrated clearly if one considers the difference between a vuggy carbonate core and a micro-porosity rich core. At low magnetic fields there appears to be little difference, but the T_2 spectra are substantially different at 2.35 Tesla (Figures 12,13). We believe that the gradient relaxation mechanism works in a similar fashion to the surface relaxation fashion in that small pores have higher magnetic field gradients and large vugs relax at nearly the bulk relaxation rate. The two relaxation mechanisms pull in the same direction to spread out the range of T_2 values observed, and as the strength of the magnetic field increases it becomes possible to more directly observe the true pore structure characteristics independent of diffusional averaging effects.

The ability to derive these data has important implications for the interpretation of low field NMR logging data. For example, when seeking to quantify vug porosity, knowledge of whether there is diffusion of fluid between the vugs, on the timescale of the low field NMR measurement, determines whether one can apply a simple cut-off method to determine the vug porosity or whether a more sophisticated approach is necessary. We are currently using the NMR images and high field relaxation data in a core analysis project to improve the interpretation of carbonate low field NMR and resistivity logs.

Flow Imaging

While static imaging can reveal gross variations in the pore space, the realization of flow anomalies requires that imaging data be acquired during a flow process. A number of new technical challenges arise.

The first of these is that the imaging must now occur in a time period that is short compared to the rate of flow. This requirement reduces the number of pulses sequences that afford useful data dramatically. In our laboratory we have found that the simple 1D line or “saturation” profile sequence is most effective. Ignoring relaxation effects, profiles can be acquired every 5 seconds. With compensation for spin-lattice relaxation effects, profiles can be acquired every 40 seconds.

Secondly, discrimination between the oil and brine phase is required. A number of techniques have attempted to discriminate between these phases based on relaxation or chemical shift effects, however the most straightforward technique is to use a deuterated brine phase (D_2O), which eliminates signal from the aqueous phase. The use of deuterium oxide is the only practical way of discriminating between oil and brine in core flood experiments because it does not require elaborate NMR pulse sequences which have significant loss of signal due to relaxation effects and permits for the shortest echo time and the simplest sequence to be used. The density difference between a deuterium oxide brine and hydrogen oxide brine is negligible and the cost is reasonable. This is better than the situation commonly found for the X-ray Computed Tomography technique in which the doping of the brine phase is carried out such that density difference is observed and in such a way that the density of the brine phase does not compare to that used for the waterflooding of the reservoir.

Flow experiments by their nature require that more time is spent in the MRI magnet and the costs usually increase substantially. A number of enhanced oil recovery experiments can and should be carried out in MRI facilities, but with regards to core analysis we tried to keep the cost factor as a priority. One place that we believe that monitoring the flow process can have an important impact is during the conditioning of the sample prior to the relative permeability measurement. Relative permeability is an experiment whose cost is substantial and the failure to take into account flow heterogeneities in the core plug leads to a skewed result. The relative permeability curve observed for the sample is the average of all the local relative permeability curves and if the flow behaviour at even one place is substantially different, then the average is distorted.

We have found that instead of monitoring the entire relative permeability process or even the waterflood event (both of which are possible), we have found that if we monitor the displacement of the initial formation brine displacement by oil prior to aging that we will detect how variable the core plug is with respect to flow. The advantage of monitoring the flow variations of the core plug before aging, is that if the core sample is very heterogeneous in its flow behaviour, the core can be removed from further consideration before wasting the time and effort of aging the sample for two months. Monitoring the final waterflood process is interesting, but it is too late and too much time and money has been spent to now find out that the core plug does not represent the flow properties of the interval of interest. A core plug with heterogeneous flow behaviour will result in either production data that is difficult to match using the relative permeability simulator or if a "best fit" is found, the answer could be very different from a core plug that has similar petrophysical properties but no flow anomalies.

CONCLUSIONS

If we believe that as core analysts we should be concerned about "heterogeneity" effects or representative samples, then the MRI screening of samples, especially carbonate reservoir plugs used for special core analysis is a necessity not a luxury. The imaging technique is non-destructive and is carried out on the same sample volume that the core analysis tests will be carried out. MRI in carbonate samples is not affected by paramagnetic distortions, largely due to the absence of iron containing mineralogy. MRI in carbonate rocks is very sensitive to the pore space and reveals the spatial distribution of micro, matrix and vug porosity. Multiple echo time imaging can identify micro-porosity regions of the sample and a reasonable estimate of the vug porosity can be made from the binary segmentation of long echo time images. Fracture detection and characterization (fluid filled or mineralised / mud damaged) can be carried out quickly and easily. The time required for lengthwise volume selective (1mm thick) MRI scans of core plugs is on the order of 30 minutes per sample, which means that the cost can be made reasonable and competitive.

In general, the monitoring of dynamic flood experiments in an MRI is costly due to the amount of time that must be used to set-up the equipment in the MRI. A practical alternative is to monitor only the brine displacement by oil before aging, so that plugs that have flow heterogeneities are removed from further consideration before wasting valuable time and resources. In carbonate core plugs this is especially important considering the difficulty of determining this information by any other method and is especially important considering that the information from the tests (relative permeability) are often used to predict the behaviour of entire zones of the reservoir. The use of deuterium oxide is a practical way of discriminating between oil and brine in core flood experiments, because it does not require elaborate NMR pulse sequences, which have significant loss of signal due to relaxation effects, and permits for the shortest echo time and the simplest NMR sequence to be used. The density difference between a deuterium oxide brine and hydrogen oxide brine is negligible, and the cost is reasonable, which permits monitoring of the immiscible displacement process under realistic density conditions.

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FIGURES

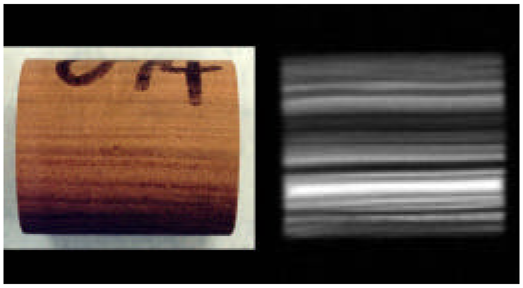

Figure 1: Sandstone core plug sample with laminations. The core photo is on the left and the corresponding full volume NMR image is on the right. The high signal intensity laminations are shown in white and are regions of higher porosity and possibly larger pore sizes. The best flow will occur in the white laminations while the flow will be retarded in the dark zones.

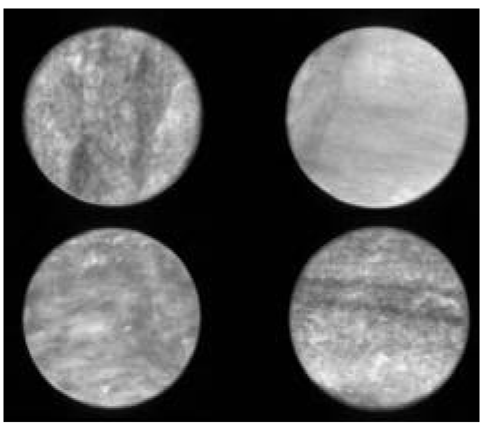

Figure 2: Four different core plugs obtained using the radial full volume MRI technique. The four core plugs have significantly different pore space features, however the volume averaging effect eliminates much of the detail (see Figure 3 for comparison).

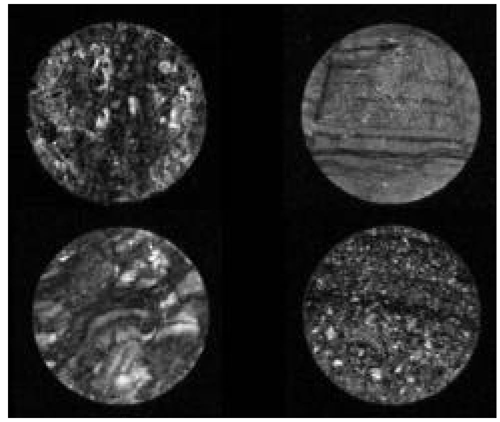

Figure 3: The same four core plugs as in Figure 2, only now obtained using thin section MRI technique such that the slice volume is less than 2 mm. The pore space definition is greatly enhanced. Regions of higher porosity are seen in white.

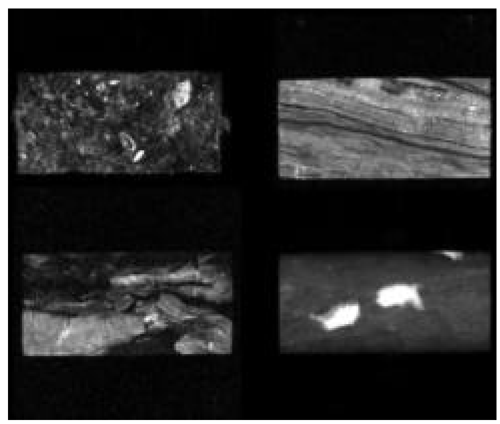

Figure 4: Lengthwise “thin section” NMR images for four different core plugs showing high definition of the pore space.

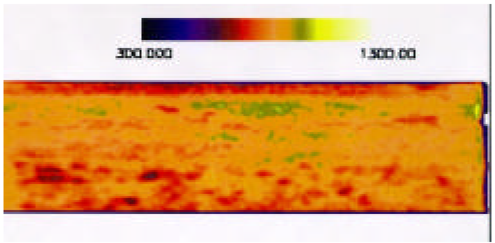

Figure 5: X-ray CT image of a carbonate reservoir core calculated from a number of radial slice images. The red spots are lower density vugs and the yellow represents regions of high density (low porosity).

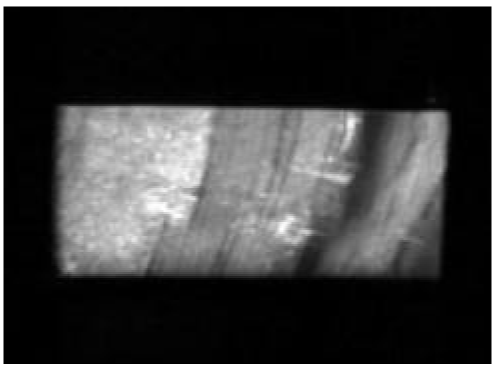

Figure 6: The same sample as in Figure 5 imaged using the MRI lengthwise full volume image technique. The NMR image shows that the sample is composed of 5 different layers, the dark section on the right indicating a region of low porosity, which possibly acts as a permeability barrier. The left hand brighter section is composed of considerable vug porosity as determined from long echo time imaging analysis. The dark lines radiating from the top and bottom are immature styolites. Even though it is a full volume NMR image, the pore space resolution of the MRI is enhanced as compared to the CT image in Figure 5.

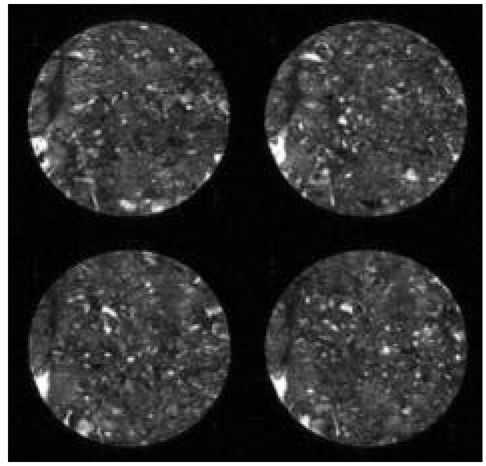

Figure 7: Short echo time NMR radial thin section images of a core plug (four images from a set of 64). The matrix and vug porosity is clearly seen.

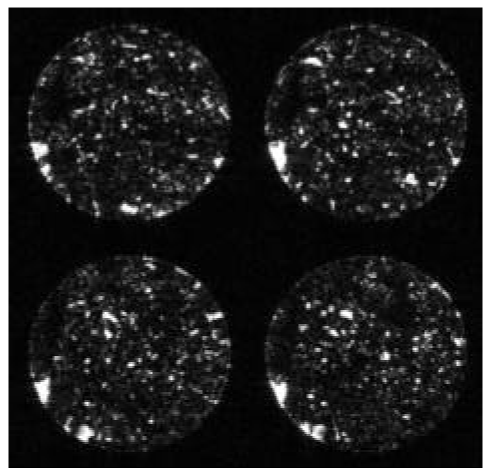

Figure 8: Long echo time NMR radial thin section images. Only the signal from the vug porosity remains. (four images from a set of 64).

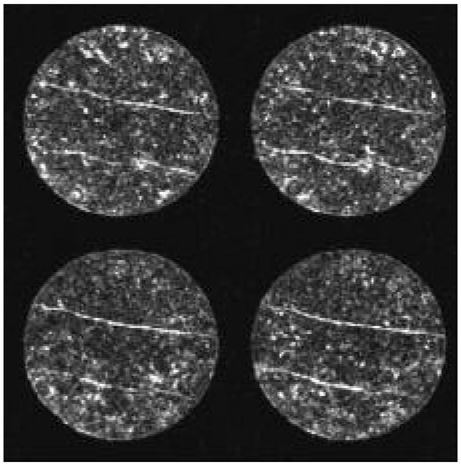

Figure 9: Fluid filled fractures are seen as white lines in these radial thin section NMR images. (four images from a set of 64). Radial images are better for capturing fracture patterns and determining their flow contribution.

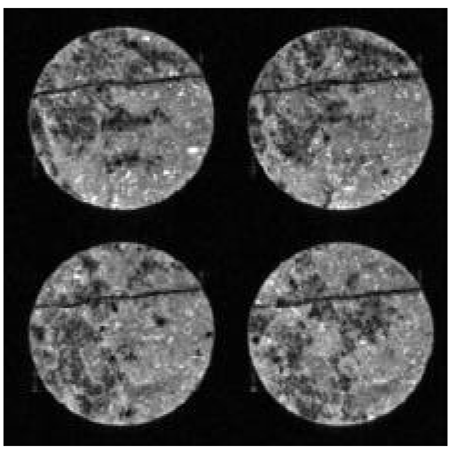

Figure 10: Mineralized or mud filled fracture which does not contribute to the flow process and is seen as dark line in thin section radial NMR images (four images from a set of 64).

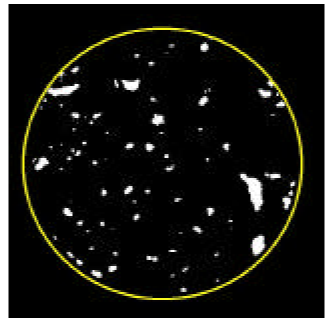

Figure 11: Binary segmented long echo time image in which the white regions represent the vugs present in the sample. From data such as this, an estimate of the vug porosity in the sample can be obtained.

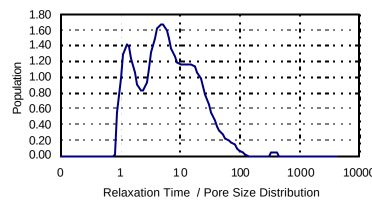

Figure 12: High field NMR relaxation spectrum of a core plug sample which has considerable micro-porosity. The T_2 values are shifted to low relaxation values due to the enhanced relaxation at the high magnetic field strength.

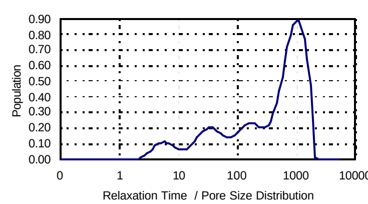

Figure 13: High field NMR relaxation spectrum of a core plug sample that has considerable vug porosity. The fluid filled vugs are relaxing at nearly the bulk diffusion rate.