Analysis of Unconventional Reservoirs using New and Existing NMR Methods

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Summary

Unconventional reservoirs offer many difficulties when attempting to analyze core data. New core analysis tools or a better understanding of traditional tools are required to adequately characterize the reservoir. NMR can provide valuable information about the pore structure and fluid dynamics and can enhance traditional core analysis measurements. Traditional NMR T_2 pore size distributions can quantify the fluids that are clay, capillary bound, free and contained within the fractures. Traditional NMR analysis constants for T_2 cut-offs yield bound water estimates that are too high when the reservoir is unconventional. We have found that a T_2 cut-off of approximate 10 msec to be more typical rather than the standard 33 msec used by the industry for low permeability reservoirs.

Capillary pressure measurements can be extremely valuable in low permeability reservoirs due to the higher pressures and larger transition region. Traditional capillary pressure measurements performed on these rocks can be extremely time consuming. A new method for acquiring capillary pressure by direct measurement of the saturation in the rock following centrifugation is presented. This method is up to 5 times faster than traditional centrifuge techniques and is well suited for unconventional reservoirs.

Introduction

Unconventional reservoirs are quickly becoming more and more common and important. Traditional core analysis techniques are often time consuming or not sufficient for these unique reservoirs. Using standard NMR well log cut-offs can lead to an incorrect assessment of the reservoir potential.

Theory

NMR detects the amount of hydrogen (for proton NMR) in the sample or object under study. The lifetime of the detected NMR signal depends on the environment of the hydrogen. For example, signal detected from the hydrogen in oil decays faster than the hydrogen in free water. In oil field exploration, we can use this to distinguish between oil, water and gas in rocks but more importantly we can distinguish between clay bound (CBW), capillary bound (BVI) and free fluid (FFI) quantities in the reservoir. A common approach to determine these quantities is to use either T_2 or T_1 relaxation times. We know that the NMR relaxation parameter T_2 follows the following equation:

$$\frac{1}{T_2} = \frac{1}{T_{2-Bulk}} + \rho\frac{S}{V} + (\gamma G T_E)^2 \frac{D_O}{12} \qquad (1)$$

Where ρ is the relaxometry constant, D_o is the free diffusion constant for the fluid, γ is the gyromagnetic ratio, G is the internal field gradient, TE is the echo time (a measurement parameter), and S/V is the surface to volume ratio of the pores. The equations reduce to direct relationships to the surface to volume ratio due to the fact that, in rocks, the bulk relaxation times are much longer than the measured values and we select an echo time (TE) such that the diffusion term can be ignored. The surface to volume ratio is a measure of the pore size distribution of the rock.

From a measurement of the distribution of T_2 or T_1, which can be done on a rock sample and using an NMR well logging tool, we get a measurement of the pore size distribution. From this we apply a cut-off value which divides the larger pores that will contain freely flowing fluid and the smaller pores that will contain bound fluid as shown in Figure 1.

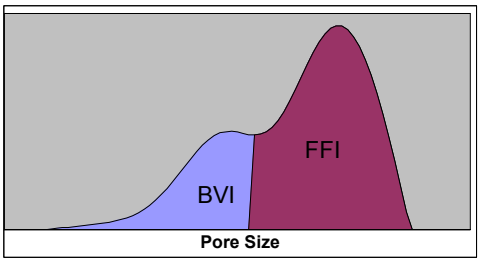

Figure 1. NMR pore size distribution showing the cut-off between bound and free fluid.

This ratio of bound to free fluid can be used to estimate the permeability as shown in Equation (2).

$$k = \left(\frac{\phi}{C}\right)^4 \left(\frac{FFI}{BVI}\right)^2 \quad (2)$$

Where C is the Coates Coefficient and ϕ is the effective porosity (porosity minus the clay bound water). The key to an accurate cut-off is the correct definition of the cut-off value. The standard cut-off for sandstone reservoirs is 33 msec (Dunn et al).

Hassler and Brunner (1945) proposed a centrifuge method to determine capillary pressure saturation data from small core plugs. In this method, a fluid saturated core plug, confined in a special core-holder, is rotated at different rotational speeds. After reaching hydrostatic equilibrium at each speed, the amount of liquid expelled from the core plug is measured. From the expelled water the saturation at the inlet face can be obtained. This saturation is plotted against the capillary pressure at the inlet as calculated from the centrifuge speed from equation (3). This procedure is repeated 7-10 times to fully define the capillary pressure curve.

$$P_c(r) = \frac{1}{2}\Delta\rho\omega^2(r_1^2 - r^2) \quad (3)$$

where $\Delta\rho$ is the density difference between the two fluids, ω is the rotational centrifuge speed, r_1 is the distance from the center of rotation and the rock's outlet face, and r is radial distance to any point along the core length.

The radial capillary pressure distribution results in a fluid saturation distribution along the length of the core. Neither of these distributions is actually measured with the traditional method. What is measured is the rotational speed, ω, and the average fluid saturation within the core. NMR can directly measure this fluid saturation distribution (Green et al, 2007). Combining the radial pressures from equation (3) and the NMR measured saturation allows capillary pressure curves to be directly obtained as shown in Figure 2.

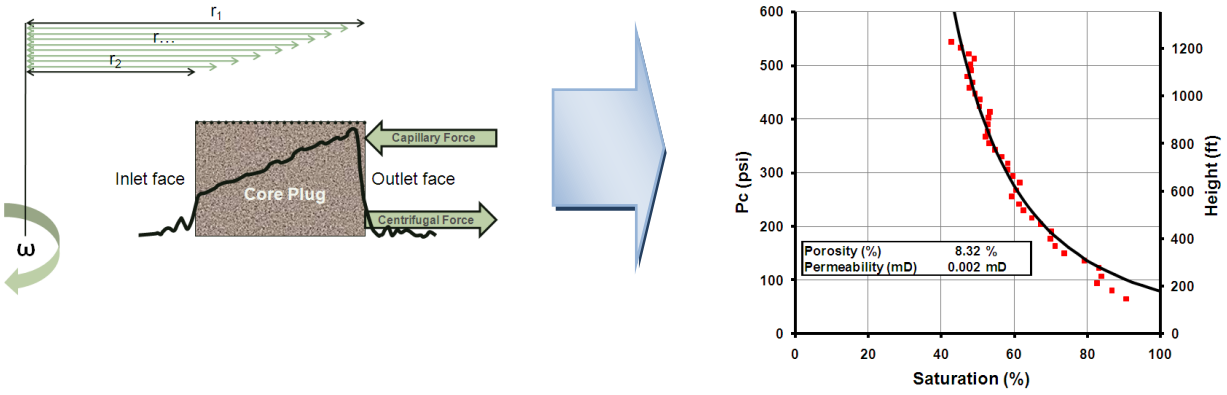

Figure 2. Process describing capillary pressure measurement using NMR acquired saturation profiles following centrifugation.

Results

NMR pore size distributions were measured on the unconventional rock samples listed in Table 1. Conventional analysis of the NMR results leads to an overestimation of the bound fluid in the reservoir thus lowering the estimated recoverable reserves. In addition, the permeability estimates will be too low. Laboratory core analysis of the rock allows us to measure the fully saturated and bound fluid NMR signals and accurately determine the cut-off. A typical result is shown in Figure 3.

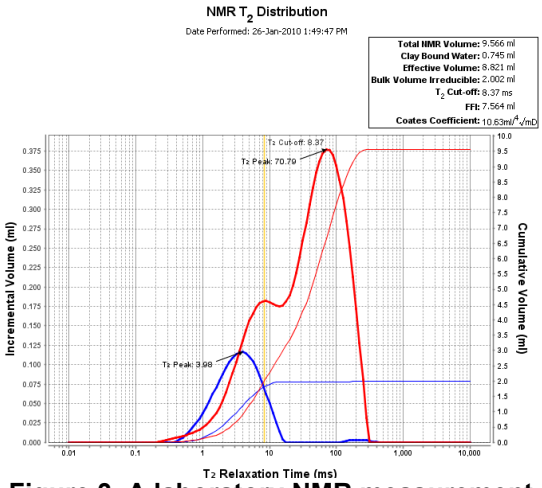

Figure 3. A laboratory NMR measurement of a rock fully saturated and at connate water saturation.

Table 1 shows the analysis of the rock showing the bound fluid (estimate and actual), the NMR permeability estimation with the estimated BVI and the true T_2 cut-off, as measured. As shown in Table 1, typical value for T_2 cut-off in low permeability sandstone and shale gas fields is around 10 msec. The traditional clay bound cut value of 2.5msec are typically too low as well. A value around 1 msec is more representative for these types of rocks.

Table 1 - NMR pore size distribution measurement on various samples.

Sample	Porosity	Permeability	BVI at 33msec	Initial NMR Perm. Est.	Measured BVI	Cut-off
1	5.71	0.003	5.25	0.000068	4.37	10.00
2	7.59	0.003	4.81	0.000080	4.81	7.08
3	4.59	0.001	4.35	0.000014	4.12	14.13
4	7.36	0.003	5.90	0.00170	4.23	7.94
5						

Measurements performed at ambient pressures on shale rock can lead to inaccurate saturation measurement as fluid will exist in fractures that are smaller at reservoir pressures. NMR offers a possible solution as the NMR signals from these fractures will appear as large pores separated from the true pore size distribution as shown in Figure 5. This gives us the true reservoir porosity and a ratio of the porosity at ambient versus at pressure. This information can be used to something goes here the saturations and possibility correct capillary pressure results.

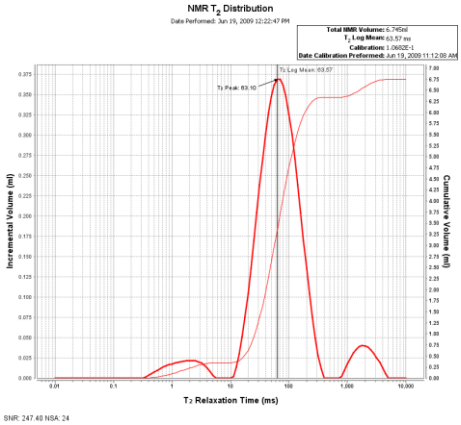

Figure 5. Typical NMR pore size distribution of a shale sample.

Conventional capillary pressure measurements of low permeability rock can be extremely time consuming. The hydrodynamic equilibrium times for centrifuge Pc (3-4 days) and porous plate (weeks or months), make these measurements time consuming. Using NMR to spatially resolve the saturation allows for many capillary pressure points to be taken at each centrifuge equilibrium, greatly reducing the measurement time while increasing the overall accuracy. Figure 4 shows a typical capillary pressure measurement that only required two centrifuge equilibrium speeds.

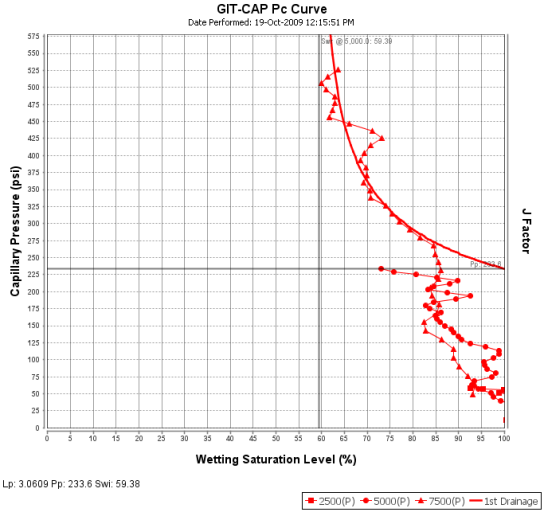

Figure 4. Typical capillary pressure curve acquired by direct measurement of the saturation profile following centrifugation.

Discussion and Conclusions

Conventional measurement and analysis techniques cannot be always be directly applied to unconventional reservoirs. Low permeability sandstone and shale reservoirs will have bound/free NMR T_2 cut-off values around 10 msec and clay bound cut off values around 1msec.

In low permeability reservoirs, the capillary pressure becomes increasingly important as more (or all) of the reservoir exists in the transition region not at the residual or connate water saturation. Accurate measurement of capillary pressure using conventional techniques is difficult and time consuming. The direct saturation measurement technique using NMR offers increased resolution/accuracy while greatly reducing the measurement time. In addition, NMR pore size distributions acquired after each centrifuge equilibrium can add additional information and be used as quality control.

Unconventional reservoirs are changing the way core data is acquired and used. Caution is required when reviewing information acquired in more traditional ways as the data may not provide an accurate understanding of the reservoir.

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