Fluid Saturations in Unconventional Reservoir Rock

Customer Need

The measurement of irreducible water and hydrocarbon saturations in fine-grain unconventional rocks by conventional protocols is difficult. The very low permeability of these samples makes it difficult to use solvents to extract liquids from unconventional core plugs, i.e. standard cleaning and drying steps are near impossible for shale plugs. While standard extraction techniques can be used on crushed samples, this precludes saturation measurements on core plugs intended for other tests. Improvements in Nuclear Magnetic Resonance (NMR) instrumentation and protocols make it possible to extend NMR interpretation methods developed on conventional rocks to small pore, high organic matter unconventional rocks.

Materials and Methods

The main advantage of using the NMR-based technique is that it allows the use of standard core plugs used for other tests. Samples can be measured in the "As-Received" state for a quick look at remaining liquids found in the pores.

Often many of these unconventional reservoir rocks lose mobile fluids, hydrocarbon gas, oil and water, during core recovery, so the initial measurement provides some insight into the relative amounts of mobile and immobile liquids.

Lost mobile liquids are replaced with crude oil or light mineral oil with pressure-saturation at temperature and pressure that in most cases fills all of the pores with liquids. A NMR measurement of a saturated sample provides a measure of the total liquid-filled pore volume.

Improvements in low-field NMR spectrometers make it possible to sense faster relaxation time components often associated with smaller pores found in shale with greater sensitivity (i.e. lower porosity values). Improved hardware/software interfaces control data acquisition and offers a broad range of NMR sequences to call on. The software also handles data processing with standard algorithms and protocols developed over 20+ years of NMR-based core studies.

In addition to well-known T_1 and T_2 sequences used in numerous core studies, modern benchtop NMR spectrometers can acquire 2D datasets (e.g. T_1-T_2, T_2-D) along with saturation profiles and oil/water distributions collected along the axis of the samples.

Dedicated sample holders make it possible to collect measurements at elevated temperatures and pressures and perform flow through displacement experiments.

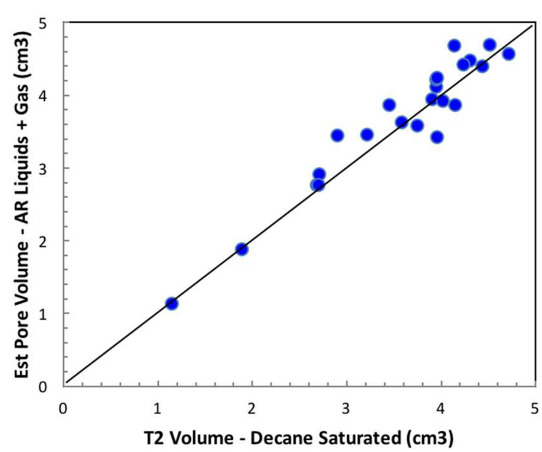

Figure 1: Comparison of pore volume measured with NMR on pressure-saturated liquid-filled core plugs vs. a standard sum-of-fluids approach.

Analysis and Interpretation

The improved sensitivity of current generation NMR spectrometers make it possible to accurately detect liquids in unconventional reservoir rock to 0.05 cm^3. There is strong agreement between the sum-of-fluids pore volume estimated on as-received samples and the pressure-saturated samples (Figure 1). Quality control of mass differences between as-received and post saturation and the measured differences in NMR volumes illustrate the resolution and reproducibility of the NMR method.

NMR T_2 relaxation time distributions in many shale lithologies have distinct relaxation components associated with water and oil saturations (Figure 2). The fast component often is associated with irreducible water in small water-wet pores while light oil relaxes at slower rates.

Often the measurement protocols must be optimized for each study based on Premier's *extensive* experience with NMR and Unconventional Reservoir rock.

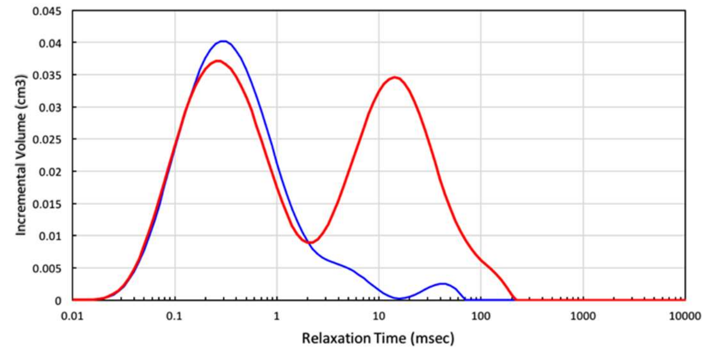

Figure 2: NMR T_2 relaxation time distributions for "As-Received" (blue) and "Saturated" (red) shale samples.

In many as-received samples, the predominant signal comes from the residual water (blue). The addition of light mineral oil (red) affects only the intensity of the slower component. Saturations are determined integrating the area under each peak. In the case of lithologies where the two relaxation components overlay, more advanced NMR techniques are applied.

2D sequences of T_1-T_2 take advantage of the different relaxation properties of oil and water under these conditions to provide estimates of saturation and total pore volume (Figure 3). Further, T_1-T_2 measurements can be used to infer the nature of pore-fluid interaction.

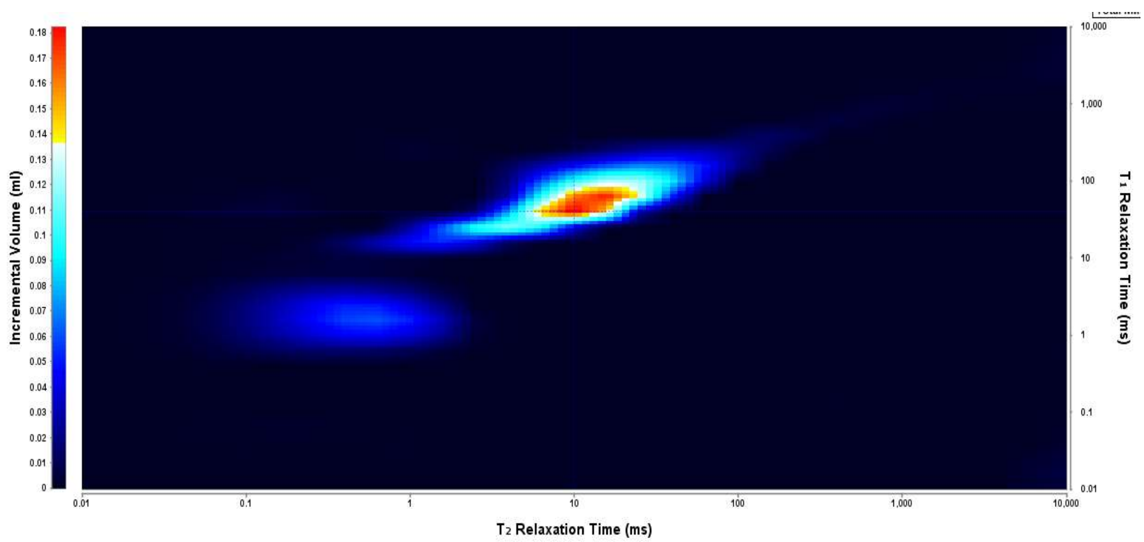

Figure 3: 2D-T_1-T_2 Map of oil-saturated shale sample with two distinct components.