Case Study of Quantification of Oil Viscosity and Saturation in Complex Reservoirs Using Advanced Nuclear Magnetic Resonance Log Interpretation Techniques

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Abstract

In the hydrocarbon exploration process, after a prospect has been identified and an exploration well has been drilled, one critical piece of information is the oil type. Earlier wireline or logging-while-drilling technologies provided rock properties and saturation information but relied on expensive sampling and testing to determine oil properties. This weakness was overcome with the introduction of nuclear magnetic resonance (NMR) logs that can provide formation properties (lithology-independent porosity, porosity distribution, and permeability, etc.) and information about the reservoir fluid viscosity.

NMR data were recently acquired in complex, high-clay content, low-salinity oil reservoirs. Traditional petrophysical interpretations throughout these reservoirs were confronted with a complex lithology (comprising feldspathic litharenites and volcanic lithic components), high clay content and low formation water salinity (3 – 4 Kppm NaCl eq). This paper shows how acquisition and interpretation of NMR data provided not only porosity and porosity distribution, but also identified oil viscosity over the logged intervals.

Advanced NMR log interpretation techniques (2D-NMR maps of diffusion (D) vs. $T_{2,int}$) were used to identify the oil NMR signal. This technique produced a continuous profile of diffusion and intrinsic T_2 distribution maps. After the oil NMR signal was identified, an estimation of the oil viscosity was also possible because D and $T_{2,int}$ are related to viscosity. Several available correlations have been used and results were comparable with production data.

Introduction

Earlier-generation NMR tools acquired only one (or a maximum of two) hydrogen spin-echo decay curves. These measurements were inverted into apparent T_2 spectra, which were separated into clay-bound, capillary-bound and movable fluid volumes. Empirical relationships can be used to convert oil T_2 distribution into crude oil viscosity information, but they require no overlap between oil and water T_2 distribution.

New-generation NMR tools use multiple frequency operations to acquire multiple echo decay curves in a single, fast logging pass. The acquisition of such large volumes of data enables the estimation of additional fundamental NMR properties (besides T_2 – transversal relaxation time): diffusivity (D) and longitudinal proton relaxation time (T_1). These properties can be plotted against each other to create two-dimensional NMR crossplots, called 2D NMR maps. As each NMR property (T_2, T_1 and D) responds differently to pore fluid content, the 2D NMR plots are useful in identifying the type, quantity and viscosity of the reservoir fluid.

The D vs. $T_{2,int}$ method has been used in several Santos wells. This 2D NMR method plots $T_{2,int}$ and D NMR properties to identify and quantify reservoir oil shows. In the 1D NMR (T_2 logging), water and oil T_2 response can overlap, but they can be differentiated in the D vs. $T_{2,int}$ crossplot because of the addition of the second fluid property: D. The diffusion coefficient for water is a constant and can be accurately predicted at every logging depth. The T_2 of water is variable, it is dependent on pore size. On the 2D crossplot (D vs. $T_{2,int}$), the water line, plotted as a horizontal line, while the oil line is plotted as a diagonal line, because both D and $T_{2,int}$ vary with the oil viscosity.

After the oil peak is identified on the 2D image, the oil show peak can be integrated and the volume can be converted to oil saturations. Oil peak D and $T_{2,int}$ values can be converted into viscosity information as both D and $T_{2,int}$ are related to viscosity.

Results

Figure 1 presents 2D NMR processing and interpretation results in one Santos well.

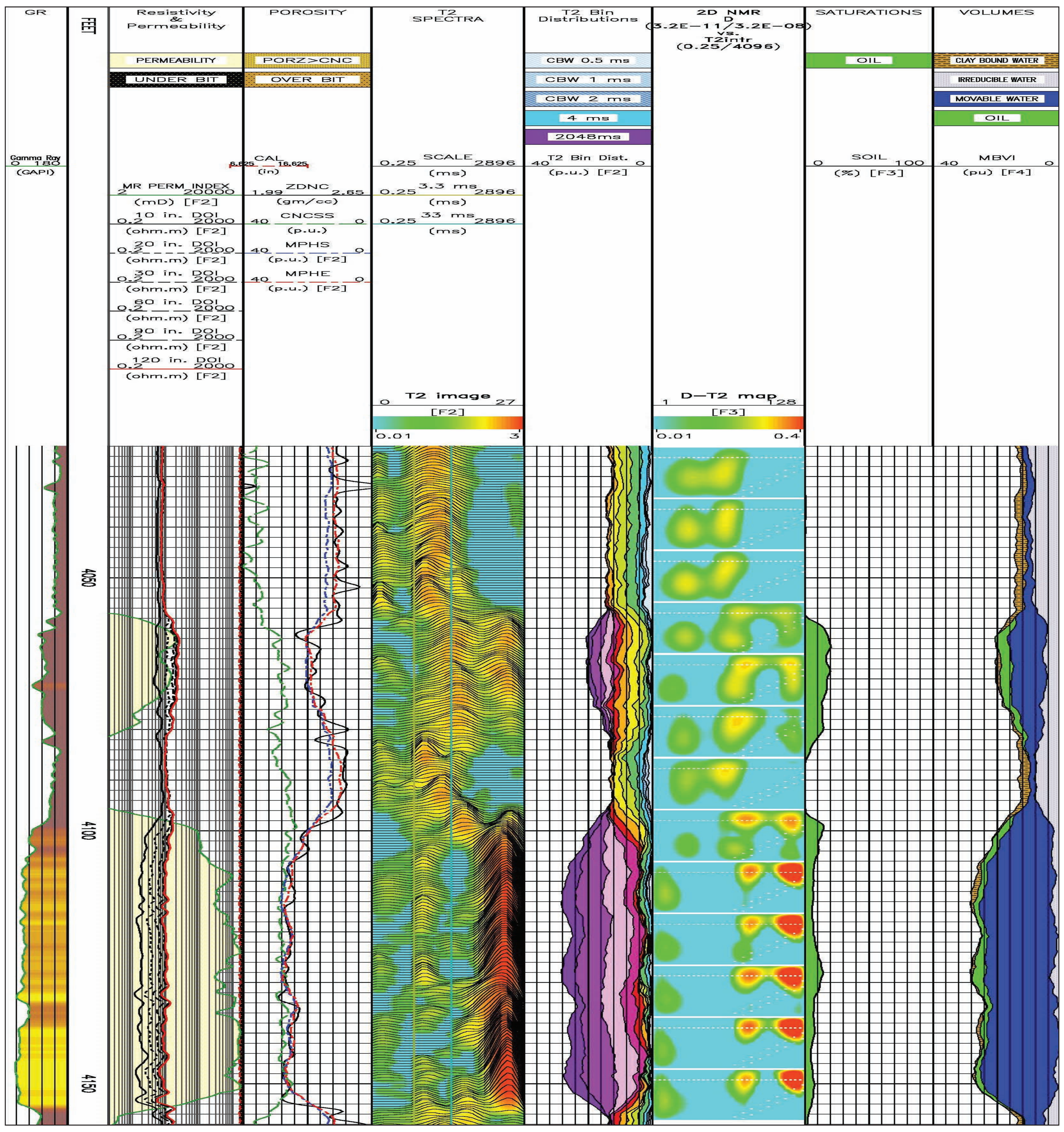

Figure 1. 2D NMR (D vs. $T_{2,int}$) results plot over an oil zone in a Santos well

Figure 1 2D NMR interpretation results indicate oil pay zones. Several peaks are located on the constant water line. The presence of several peaks indicates a clay-bound water peak (located left on the line), water in medium-size pore space (peak located on the middle) and water in the large pore size (located right on the line). Water in the large pore size correlates with the increase in permeability and the absence of clay-bound water. This indicates a transition from shaly sands toward cleaner sand, or if in a laminated shale sand environment, a decrease in laminated shale presence from top to bottom (an increase in formation net to gross). The location of the oil peak is on the oil line close to the intersection of the parallel water line with the diagonal oil line. This indicates the presence of very light oil. The oil peaks are not individually separated; they overlap with free water located in the large pores. The mixed peak extends from the parallel water line to the diagonal oil line. A presence of water and oil in the large pore is expected, because the NMR has a shallow depth of investigation (less than 4 in.) and the investigated interval is affected by invasion. The integration of the volume under the oil peaks enables an evaluation of oil saturation (see the two tracks from the right of Figure 1).

Figure 2 presents the integration of oil peak across one well interval. The rectangle parameters are chosen by inspecting the individual 2D NMR images. A selection of parameters is presented on top of Figure 2. Oil saturation based on the selected rectangle parameters is computed and presented on the right side of Figure 2. If different oil types are identified on the 2D NMR image, the 2D NMR processing can be zoned, and different rectangle (or other geometrical polygon) parameters can be used.

As both D and $T_{2,int}$ are related to viscosity, the volume under the selected rectangle can be computed using different formulas (Rice, Vinegar or a Baker Hughes proprietary formula). A 2D NMR interpretation can be seen in Figure 3.

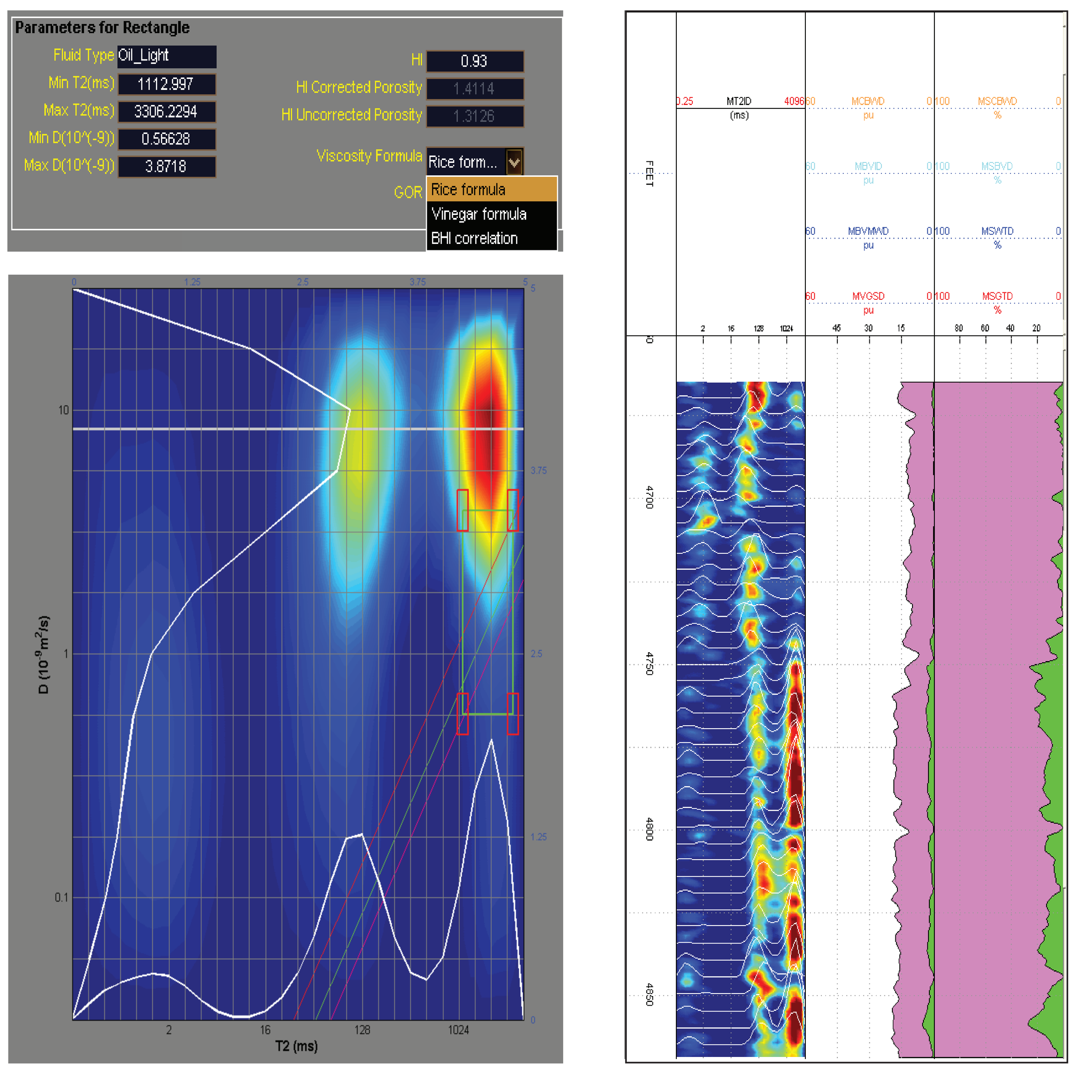

Figure 2. 2D NMR hydrocarbon peak selection over full processed interval

From the 2D NMR maps (see track 7, Figures 3) close-contact light oil peak and water peak can be seen in the large pores. Visual inspection of 1D NMR images (T_2 – Track 5, $T_{2,int}$ – Track 9, D – Track 11) suggests there is no clear separation of the oil peak. On the X-axis projection ($T_{2,int}$) of the 2D NMR plots, the oil peak and water peak in large pores overlap, whereas on the Y-axis projection (D) of the 2D NMR plots there is no clear separation between oil peak and the multitude of peaks located on the parallel water line. This exemplifies the limitations of 1D NMR interpretation in comparison with 2D NMR methods.

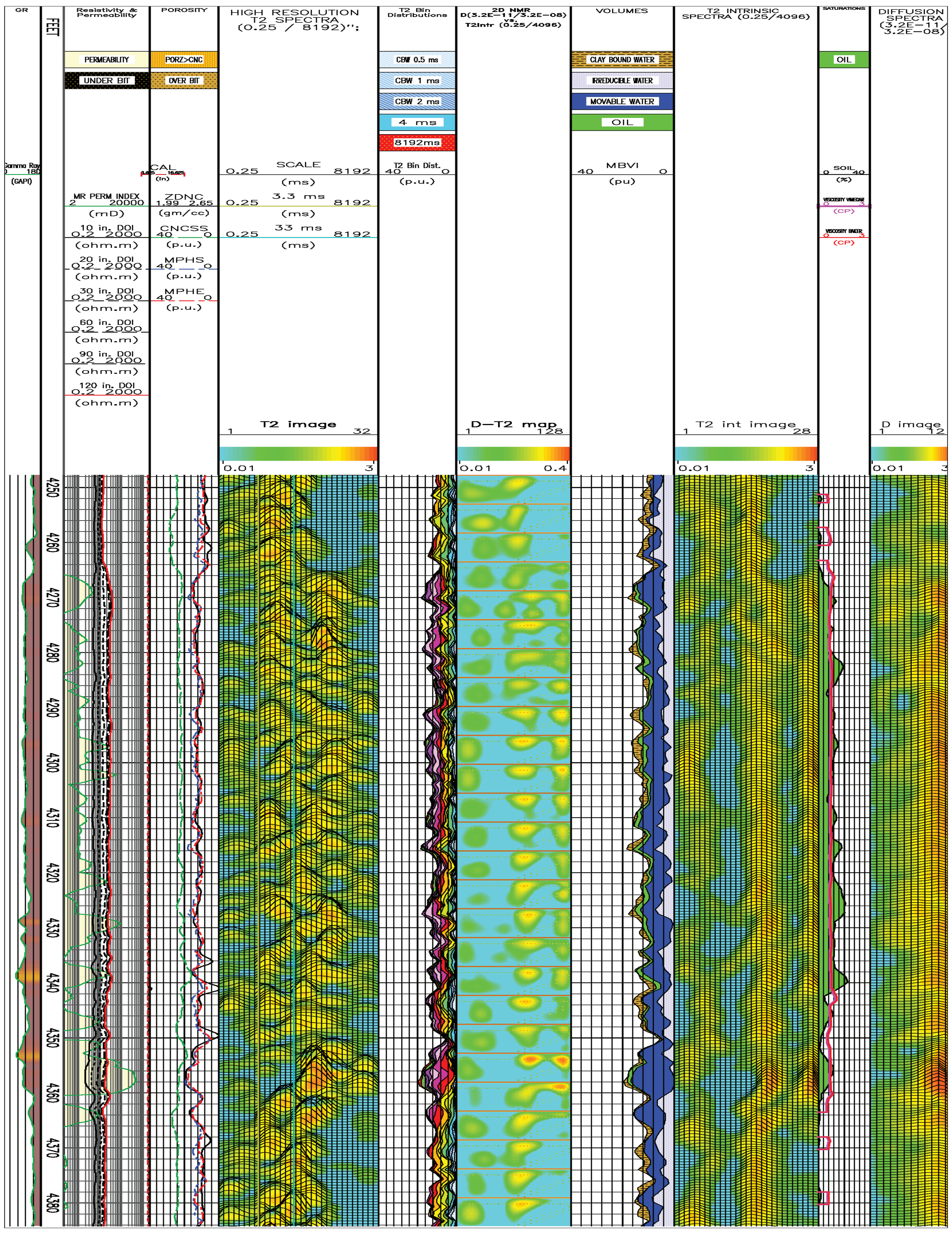

Figure 3. Viscosity estimation, T_2, T_1, $T_{2,int}$ and D curves, 2D NMR D vs. $T_{2,int}$ plot in a Santos well

Track 10 of Figure 3 presents the computed oil viscosity using Vinegar and Baker Hughes formula. The Rice formula has not been used as it requires an opriori knowledge of formation GOR. Oil viscosity at reservoir conditions has been estimated at an average of 0.6 cp. This value matches well the produced oil viscosity and has been used for well-performance analysis as no samples or pressure testing have been acquired.

Conclusions

Santos acquired NMR data in several exploration wells with the goal of improving the petrophysical evaluation in a reservoir comprising a complex lithology of feldspathic litharenites and volcanic lithic components, high clay content, and low formation water salinity (3 – 4 Kppm NaCl eq).

The 2D NMR method (D vs. $T_{2,int}$) has been used to identify the viscosity and provide interpretation of oil saturation. An advantage of this technology is that the interpretation is independent of lithology and formation water, while the near-wellbore saturation model (S_{xo}) requires no resistivity input. NMR acquisition also provided information for controlling performance of these wells by providing estimates of permeability and viscosity.

This paper shows how acquisition and interpretation of NMR data provided not only porosity and porosity distribution, but also identified and quantified oil shows over the logged intervals.