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Gas Identification in Thin Beds Using LWD Measurements – West Africa Offshore Example*

Stanley Oifoghe[1], Ono Daniel[2], Victor Okowi[2], Charlie Thompson[3], and Ikechukwu Nwabueze[2]

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[1]RDS - Geoscience, Baker Hughes, Port Harcourt, Rivers State, Nigeria (stanleyoifoghe@yahoo.com)
[2]RDS - Geoscience, Baker Hughes, Port Harcourt, Rivers State, Nigeria
[3]Foxtrot International, Abidjan, Côte d'Ivoire

Abstract

Gas identification and determination of Gas-Oil Contact (GOC) in reservoirs containing gas and oil can be a major challenge in laminated sand-shale sequences, where the presence of shales drastically affects the response of gamma ray, resistivity, density, and neutron logs. Due to the resolution of these measurements, it becomes increasingly difficult to identify and quantify the gas reservoirs. In a West Africa Offshore well in a Cretaceous formation, using a Pentacombo Bore Hole Assembly (BHA) with basic Formation Evaluation (FE) measurements, the use of additional services such as Nuclear Magnetic Resonance (NMR) and Formation Pressure Tester Logging While Drilling (LWD) services, significantly improved the confidence in interpretation of the reservoir fluids. In the example well, though the size of the density-neutron crossover showed a reduction in the oil zone as compared to the gas zone to a certain degree, the actual position of the Gas/Oil contact and the reservoir fluid saturation were not certain. Using the traditional NMR porosity undercall in gas zones as well as the dual wait time (DTW) transverse relaxation time (T_2) distribution analysis, the gas zone was confirmed and the saturation of each of the fluids in the reservoir was accurately determined. The NMR tool was programmed to acquire data in dual wait time (DTW) mode. The Magnetic Resonance Dual Wait Time (DTW) approach takes advantage of Longitudinal Relaxation Time (T_1) contrast to solve for hydrocarbon saturation. “In light hydrocarbons, in a water-wetting reservoir, the hydrogen atoms in the hydrocarbon fluid relax slower than the nonmovable and movable water. By using two polarization or wait times (T_W), it is possible to calculate hydrocarbon saturation using magnetic resonance tools” (Thorsen et al., 2008). Due to the low hydrogen index of gas, the short wait time will only polarize a fraction of the porosity in the gas zone while achieving a near full polarization in the liquid (oil or water) zone. The same hydrogen index effect was evident in the total porosity computation from NMR measurement. Significantly lower porosity was observed in the gas zone as compared to the oil zone. This was the first indication of Gas Oil contact (GOC). Further analysis of the dual wait time T_2 distribution gave a proper estimate of the saturation of the fluids in the reservoir.

Discussion

Gas identification and determination of Gas-Oil Contact (GOC) in reservoirs containing gas and oil can be a major challenge in laminated sand-shale sequences, where the presence of shales drastically affects the response of gamma ray, resistivity, density, and neutron logs. Due to the resolution of these measurements, it becomes increasingly difficult to identify and quantify the gas reservoirs. Gamma ray response is affected by the presence of feldspathic sands with radioactivity similar to that of shales. The presence of adjacent shales gives rise to shoulder bed effects encountered when taking resistivity measurements. This is a major cause of electrical anisotropy with the attendant reduction of the formation resistivity of the reservoir sands. The shallow investigation of the density and neutron measurements results in investigation of the flushed zone. The difficulty of determining the appropriate fluid properties of the flushed zone makes the characterization of gas reservoirs in laminated sequences an uphill task.

In a West Africa offshore well in a Cretaceous formation, using a Penta-Combo Bore Hole Assembly (BHA) with basic Formation Evaluation (FE) measurements, the use of additional services such as Nuclear Magnetic Resonance (NMR) and Formation Pressure Tester Logging While Drilling (LWD) services, significantly improved the confidence in interpretation of the reservoir fluids. The example well is an evaluation well drilled on the continental shelf with a Jack-Up Driller. The reservoir sands are of Cenomanian age. Dual Wait Time approach was used to determine Hydrocarbon Saturation while Hydrocarbon Viscosity was computed using Vinegar Equation. Oil was found in the lower sand while Gas was found in the upper sand.

In the example well, though the size of the density-neutron crossover showed a reduction in the oil zone as compared to the gas zone to a certain degree, the actual position of the Gas/Oil contact and the reservoir fluid saturation were not certain. Using the traditional NMR porosity under-call in gas zones as well as the dual wait time (DTW) transverse relaxation time (T_2) distribution analysis, the gas zone was confirmed and the saturation of each of the fluids in the reservoir was accurately determined.

The NMR tool was programmed to acquire data in dual wait time (DTW) mode to calculate hydrocarbon saturation. The Magnetic Resonance Dual Wait Time (DTW) approach takes advantage of Longitudinal Relaxation Time (T_1) contrast to solve for hydrocarbon saturation. “In light hydrocarbons, in a water-wetting reservoir, the hydrogen atoms in the hydrocarbon fluid relax slower than the non-movable and movable water. By using two polarizations or wait times (T_w), it is possible to calculate hydrocarbon saturation using magnetic resonance tools” (Thorsen et al., 2008). Due to the long T_1 of gas, the short wait time will only polarize a fraction of the porosity in the gas zone while achieving a near full polarization in the liquid (oil or water) zone.

Also, the gas hydrogen index effect was evident in the total porosity computation from NMR measurement. Significantly lower porosity was observed in the gas zone as compared to the oil zone. This was the first indication of Gas-Oil contact (GOC). Further analysis of the dual wait time T_2 distribution gave a proper estimate of the saturation of the fluids in the reservoir.

Dual Wait Time (DTW) – Differential Spectrum

Magnetic Resonance Dual Wait Time (DTW) approach associates differences in Longitudinal Relaxation Time (T_1) [based on short wait time

(T_w)] with different fluid types. Water has short T_1 and T_2, oil has longer T_1 and T_2, and Gas has longest T_1 and T_2. In light hydrocarbons in a water wetting reservoir, the hydrogen atoms in the hydrocarbon fluid would relax slower than the non-movable and movable water (Thorsen et al., 2008). By use of two different polarization times [Wait Times (T_w)] it is possible to calculate hydrocarbon saturation using magnetic resonance tools. By using a long wait time, both the hydrogen atoms in the water and hydrocarbons will be polarized. By applying a shorter wait time, the hydrogen atoms in the water will be polarized and only a small fraction of the hydrogen atoms in the hydrocarbons will be polarized. If the bulk longitudinal relaxation of the hydrocarbon in pore space is known, hydrocarbon saturations can be estimated by following equations:

Long wait time: $$\mathrm{MPHS_L} = \emptyset\, \mathrm{S_{HC}}\, \mathrm{HI_{HC}} \left(1 - \mathrm{e}^{-\frac{\mathrm{TW_L}}{T_{1HC}}}\right) + \emptyset\,(1 - \mathrm{S_{HC}})\, \mathrm{HI_W P_W}$$

Long wait time: $$\mathrm{MPHS_3} = \emptyset\, \mathrm{S_{HC}}\, \mathrm{HI_{HC}} \left(1 - \mathrm{e}^{-\frac{\mathrm{TW_S}}{T_{1HC}}}\right) + \emptyset\,(1 - \mathrm{S_{HC}})\, \mathrm{HI_W P_W}$$

For $\mathrm{TW_L} \gg T_{1HC}$, difference can then be expressed as $$\Delta\varphi = \emptyset\, \mathrm{S_{HC}}\, \mathrm{HI_{HC}} \left(\mathrm{e}^{-\frac{\mathrm{TW_S}}{T_{1HC}}}\right)$$

Hydrocarbon saturation, ratio of HC porosity to total porosity can then be expressed as:

$$\mathrm{S_{HC}} = \frac{\Delta\varphi}{\emptyset\left(\mathrm{HI_{HC}}\left[\mathrm{e}^{-\frac{\mathrm{TW_S}}{T_{1HC}}}\right]\right)} = \frac{\Delta\varphi}{(\mathrm{HI_{HC}}[\emptyset])}\left(\mathrm{e}^{\frac{\mathrm{TW_S}}{T_{1HC}}}\right)$$

$\mathrm{MPHS_{L\ [pu]}}$ – Total porosity of the formation, bound and free fluid; derived from the echo train with long TW (ET_TWL)

$\mathrm{MPHS_{3\ [pu]}}$ – Total porosity of the formation, bound and free fluid; derived from the echo train with short TW (ET_TWS)

TW – Wait time. The time needed to build up the magnetization, typically several seconds

$\mathrm{TW_L}$ – Long Wait time. The time needed to build up the magnetization for the entire fluid composition

$\mathrm{TW_S}$ – Short Wait time. The time needed to build up the magnetization for the water fraction

$\mathrm{HI_{HC}}$ – Hydrogen index of hydrocarbon

HI_W – Hydrogen index of water

Pw – Polarization of water (equal 1 for TWL and TWS, since both TW are much larger than T_1, H_2O)

$\Delta\varphi$ [pu] – Differences of total porosity (ET_TWL) and under-polarized porosity (ET_TWS), indicative of hydrocarbons; derived from differential echo train (ET_TWL – ET_TWS)

T_{1HC} – Bulk longitudinal relaxation of the hydrocarbon in the pore space

S_{HC} [fraction] – Hydrocarbon saturation, ratio of HC porosity to total porosity; derived from differential echo train signal including information T1 of the hydrocarbon and total porosity

Vinegar Equation

$$\mathrm{T}_2 = \frac{4.T_K}{\mu}$$

T_2 – Transverse relaxation time

T_K – Temperature in Kelvin

μ – Hydrocarbon Viscosity

Using the magnetic resonance data, gas was interpreted at the top of the reservoir while oil was interpreted at the bottom. The gas-oil contact (GOC) is indicated by the superimposed pressure gradient plot. The increase in hydrocarbon viscosity below the GOC is also a good indication of the position of the GOC. The GOC was confirmed from the change in the T_2 Spectrum (Figure 1) and the reduction in density-neutron crossover.

Though, the magnetic resonance T_2 Spectrum and dual wait time results show the presence of gas at the top of the reservoir, the absence of an expected density-neutron cross-over gives rise to uncertainties. There is therefore a need to devise other means of confirming the presence of gas at the top of the reservoir, and invariably delineating the reservoir top.

The change in T_2 Spectrum below the Oil-Water Contact, the drop in resistivity reading and the little or no density neutron cross-over of this interval, indicates the presence of water. The little density-neutron cross-over in the water zone is attributable to the oil base mud filtrate from the oil base mud used in drilling the well. The OWC was also confirmed from the superimposed pressure gradient plot.

The third track shows the Long T_2 Spectrum, the fourth track shows the short T_2 Spectrum, while the fifth track shows the differential spectrum after the short wait time is subtracted from the long wait time. As expected, the water signal is missing from the T_2.

In addition to identifying the gas and determining the gas-oil contact, it was necessary to determine the total height of the gas in the reservoir. This is important because the density-neutron cross-over does not extend to the top of the reservoir. For this analysis, we computed the total porosity of the reservoir using the stochastic or probabilistic formation evaluation technique and compared the result with the total porosity derived from the magnetic resonance tool (Figure 2). It should be noted that the use of several log measurements like gamma ray, resistivity, density, and neutron will help in correcting for the effect of shale and gas in the porosity determined from stochastic analysis, whereas, the low hydrogen index of the gas will affect the total porosity derived from the magnetic resonance tool. Though, the effect of low hydrogen index of the gas on the magnetic resonance porosity can be corrected for, if the hydrogen index of the gas is known; the procedure is beyond the scope of this paper.

It was observed that the total porosity from Stochastic Analysis, Phit (red curve in track 6) and the total porosity from the Magnetic Resonance, MPHS (blue curve in track 6) match perfectly in the oil and water zones because oil and water both have hydrogen indices of about 1, while there was a separation between Phit and MPHS in the gas zone, Phit being consistently higher than MPHS, as a result of the low hydrogen index of the gas (0.3).

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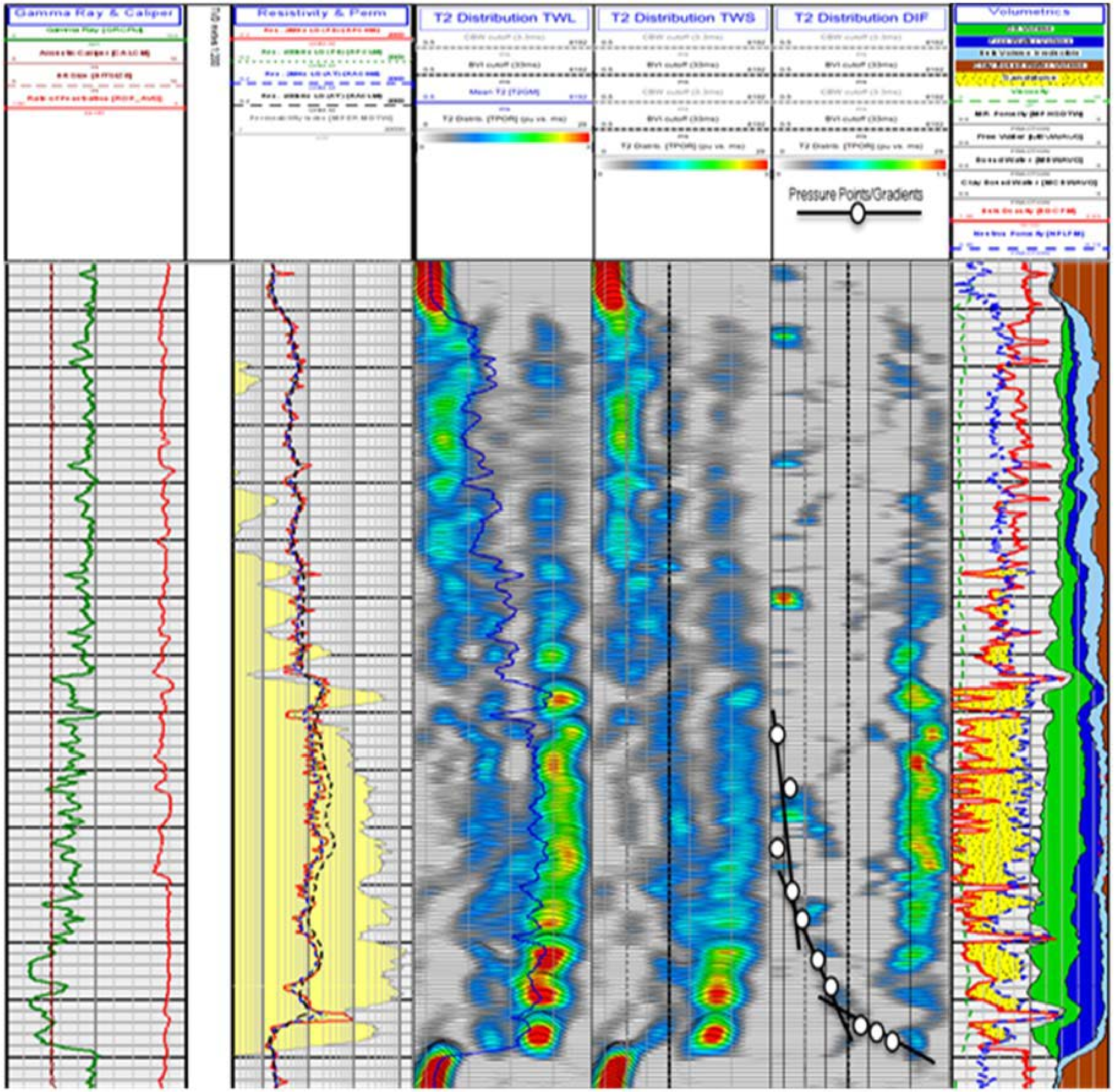

Figure 1. T_2 Differential Spectrum.

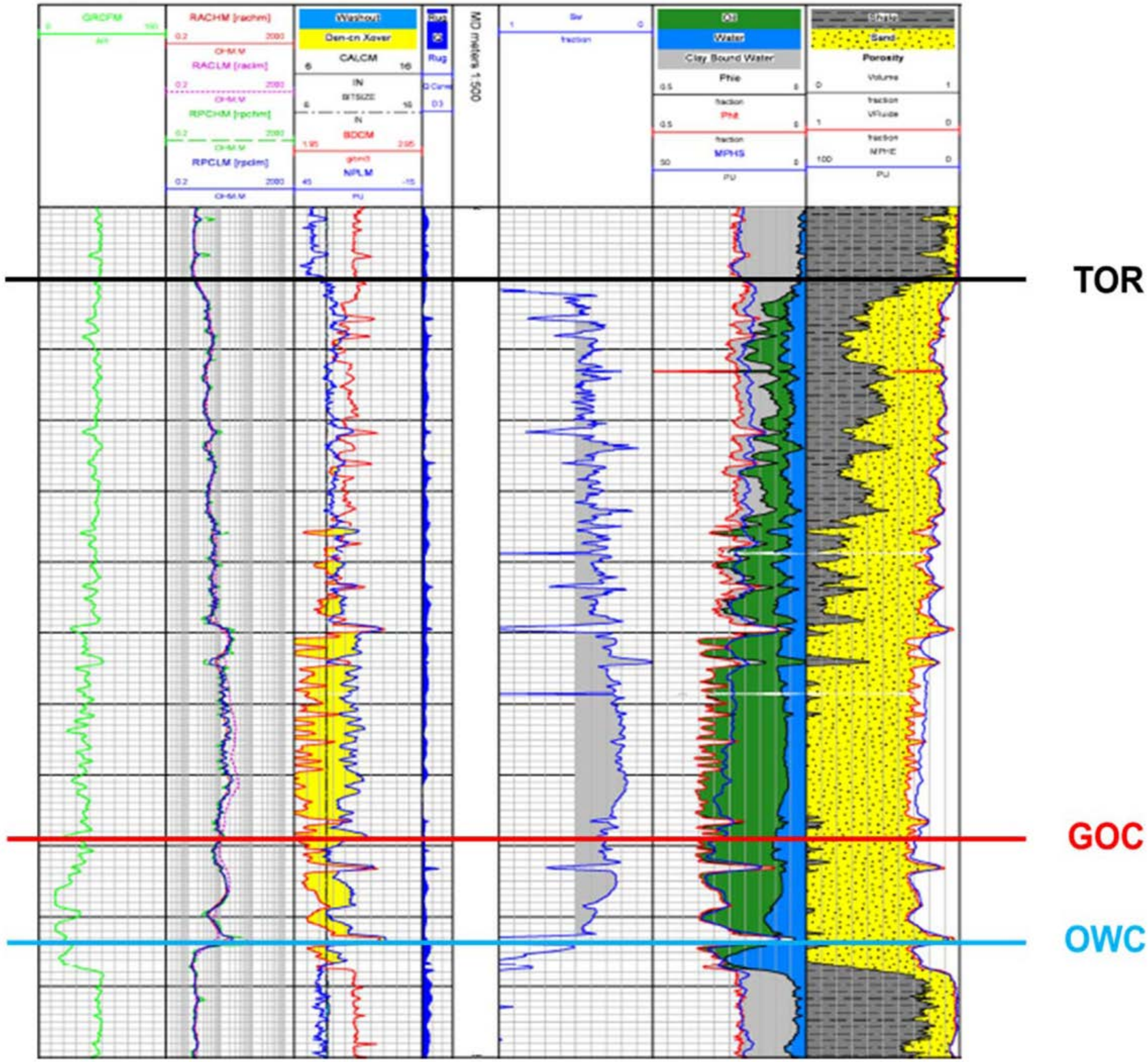

Figure 2. Comparison between Total Porosities of Stochastic Analysis (Phit) and Magnetic Resonance (MPHS).