

## **How to Obtain Primary Drainage Capillary Pressure Curves Using NMR T<sub>2</sub> Distributions in a Heterogeneous Carbonate Reservoir**

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### **ABSTRACT**

Nuclear Magnetic Resonance (NMR) derived T<sub>2</sub> distributions have long been recognised as providing valuable information about pore size and fluid distribution in reservoir rocks. Conventional methods for deriving water saturation from T<sub>2</sub> distributions use the T<sub>2</sub> cut-off method, this determines the bound fluid saturation. The T<sub>2</sub> cut-off method models water saturation at a theoretical irreducible water saturation, it does not account for transition zone water saturations.

The fully brine-saturated sample T<sub>2</sub> distribution can be thought of as a ‘pseudo’ pore-size distribution. This property has been used by researchers to convert T<sub>2</sub> distributions to capillary pressure curves. Single conversion factor/scaling factors have been used, but this assumes that the pore space has a single surface relaxivity value and resembles a bundle of capillary tubes. Methods using variable scaling factors have been published. A variable scaling factor takes account of variable surface relaxivity throughout the pore space and the existence of pore body restrictions/throats. All previous published studies have been on sandstone reservoir rocks

This work investigates the use of core calibrated variable scaling factors to derive capillary pressure curves from log NMR T<sub>2</sub> distributions in a heterogeneous carbonate reservoir. The resulting capillary pressure curves are used to predict water saturation in a hydrocarbon column hundreds of metres thick.

The variable scaling factor functions are obtained using mercury injection primary drainage capillary pressure curves and brine-saturated T<sub>2</sub> distributions from plug samples. We discuss methods for evaluating heterogeneity at the plug scale and assessing the validity of the derived scaling factor functions in highly heterogeneous carbonate rocks. The scaling factor functions can be used to convert the NMR log data to modelled mercury injection curve at every depth interval. The resulting capillary pressure curves are converted to reservoir conditions using special core analysis and fluid property data. Knowing the height above free water level, the water saturation at each depth can be estimated. The resulting water saturation is compared with the NMR log T<sub>2</sub> cut-off water saturation and log water saturation from resistivity based models. Recommendations are made on sample selection strategies and special core analysis data required to obtain accurate water saturations using this methodology in heterogeneous carbonate reservoirs.

## INTRODUCTION

Nuclear Magnetic Resonance (NMR) measurements have been used extensively to characterise reservoir rock pore geometry using logging and lab based NMR spectrometers [1]. NMR can be used to model permeability, free fluid and bound volumes. The sensitive of the NMR measurement to pore-size distribution potentially enables capillary pressure to be modelled from NMR data. Several workers have proposed methods to derive drainage capillary pressure vs saturation curves from NMR data [2-4]. This paper demonstrates how to use core plug capillary pressure and NMR T<sub>2</sub> data to obtain modelled capillary pressure curves from NMR logs in a heterogeneous carbonate reservoir.

## NMR THEORY

In simple terms in NMR we are measuring the relaxation behaviour of hydrogen nuclei [5]. In this study, we measure the T<sub>2</sub> relaxation of the hydrogen nuclei. In most porous rock systems, there will be a continuous range of pore sizes, rather than several discrete sizes. In fully brine saturated rocks each pore-size has a distinctive T<sub>2</sub> value. The NMR response to one pore-size will have a characteristic T<sub>2</sub> value and signal amplitude proportional to the amount of fluid contained in pores of that size. For examples within this paper a CPMG sequence (Carr-Purcell-Meiboom-Gill) is used to measure NMR T<sub>2</sub> distributions of core plugs and in the NMR log.

In a water-wet rock, relaxation of hydrogen protons in the water occupying the smallest pores occurs, because of interaction with the pore surfaces. Part of the T<sub>2</sub> distribution relates to water in pores which could be displaced by hydrocarbons and part relates to capillary-bound water. The T<sub>2</sub> cut-off method is often used to define capillary bound water volumes, the defaults for carbonates is 100ms. Using a T<sub>2</sub> cut-off value to define capillary bound water for NMR logs will assume that all rocks are at an irreducible water saturation and does not account for a transition zone. Therefore, to use NMR logs to accurately define water saturations it is beneficial to convert the NMR T<sub>2</sub> distributions to capillary pressure curves and calculate the saturation at each given height above the free water level.

## MERCURY INJECTION VS NMR

Mercury injection utilises the very high interfacial tension between mercury and air to produce capillary pressure data up to extremely high capillary pressure and obtain low wetting phase saturations. Details on mercury injection theory and experimentation can be found in Shafer & Neasham (2000) [6]. Mercury injection capillary pressure (MICP) curves can be converted to a pore size distribution by rearranging the Washburn equation, Equation 1.

$$r = \frac{-C 2\sigma\cos\theta}{P_{C_{MICP}}} \quad (1)$$

Where:  $r$  = Pore radius (microns),  $P_{C_{MICP}}$  = Mercury injection capillary pressure (psia),  $\sigma$  = Mercury/air interfacial tension (485 dynes/cm),  $\theta$  = Contact angle between the mercury/air interface & the rock (130°),  $C$  = A unit conversion factor

The NMR  $T_2$  distributions are not ‘anchored’ to any points of reference, it can be ‘calibrated’ to the distribution of pore throat radii data using a scaling factor, Equation 2.

$$\text{Scaling Factor} = \frac{-C 2\sigma\cos\theta}{Pc_{MICP} \times T_2} \quad (2)$$

Using a single scaling factor assumes that a linear relationship exists between pore throat radius and pore body size. Also, the NMR is recorded on the entire plug whereas the MICP data is measured on a plug trim. The MICP may not be representative of the plug, especially if there are small scale heterogeneities within a plug. Figure 1 shows a sandstone example in which a single scaling factor works well. Figure 2 shows a vuggy carbonate sample example. The pore-space of this vuggy carbonate sample has pores arranged such that small pores ‘shield’ larger pores. Hence the mercury injection derived pore size distribution is unimodal & the  $T_2$  distribution is multi modal. The example in Figure 2, illustrates why a scaling factor function is required for complex pore systems such as vuggy carbonates.

## THE DATA SET

The dataset used for this study includes: 16 plug samples with high pressure MICP curves and NMR  $T_2$  measurements at 100% brine saturation. The plug samples are all from a carbonate reservoir. Figure 3 shows the ambient Klinkenberg gas permeability against ambient helium porosity for the clean dry plug samples. Samples from this reservoir are known to be heterogeneous and can contain large vugs. To evaluate the degree of heterogeneity the absolute percentage difference between the helium porosity of the MICP trim and total NMR porosity of the plug was calculated, Figure 4. Samples with large differences are likely to be those in which heterogeneity on the plug scale is high. This means that a mercury injection ‘trim’ cut from the plug may not be representative of the whole plug. Every plug in this study was imaged using CT scanning. Inspection of the CT scan images confirmed that plugs with small differences in the two porosity values appear to be reasonably homogeneous, Sample 16, Figure 5. Plugs with large differences in porosity between plug & trim are were confirmed to be heterogenous from their CT scan images, Sample 3, Figure 5. Only plugs with an absolute difference of less that 20% between trim and plug porosity are used to calibrate the global scaling factor model. The well was logged using the Schlumberger MRX tool.

## CONSTRUCTING THE GOLBAL SCALING FACTOR MODEL

Figure 6 shows the workflow used in this study. All mercury injection and NMR measurements were at zero confining stress (ambient), therefore both NMR and mercury injection curves were stress corrected using the Juhasz method in Equations 3a, 3b and 4.

$$Pc(res) = Pc \times \left[ \frac{\phi_{res}}{\phi_{lab}} \right]^{-0.5} \quad (3a)$$

$$T2(res) = T2 \times \left[ \frac{\phi_{res}}{\phi_{lab}} \right]^{-0.5} \quad (3b)$$

Where:  $P_c$  = Capillary pressure at zero confining stress (psia),  $P_c(res)$  = Capillary pressure at reservoir equivalent confining stress (psia),  $T_2$  =  $T_2$  relaxation time at zero confining stress (mS),  $T_2(res)$  =  $T_2$  relaxation time at reservoir equivalent confining stress (psia),  $\Phi_{res}$  = Porosity at reservoir equivalent confining stress (fraction),  $\Phi_{lab}$  = Porosity at zero confining stress (fraction)

$$S_{nw}(res) = S_{nw} \times \left[ \frac{\Phi_{res}}{\Phi_{lab}} \right] \quad (4)$$

Where:  $S_{nw}$  = Non wetting phase saturation at zero confining stress (fraction),  $S_{nw}(res)$  = Non wetting phase saturation at reservoir equivalent confining stress (fraction)

Previous studies proposed using a single scaling factor to convert  $T_2$  distributions to capillary pressure curves, this study uses a scaling factor for every saturation point. Thus ‘forcing’ the  $T_2$  distribution to match the capillary pressure curve, Figure 7. The scaling factor for each saturation point is the multiplier needed to convert the  $T_2$  time to the equivalent capillary pressure. Doing this accounts for the varying degree of pore-shielding and surface relaxivity that occurs within the pore-space over the whole range of pore sizes. A scaling factor versus saturation function is defined for each sample, Figure 8. A global scaling factor relationship can be obtained by calculating the best fit scaling factor for each saturation unit using all samples. This data set produced a polynomial relationship. There is a larger variation in scaling factors at saturations greater than 0.6. This corresponds to larger pores and indicates that for these samples surface relaxivity & pore-shielding is variable in these larger pores.

The global scaling factor relationship has been applied to the stress converted  $T_2$  distributions for each plug. Figure 9 shows a comparison of the modelled capillary pressure curve with the measured mercury injection capillary pressure curve for Sample 4. For the set of sixteen samples over 80% had a root mean squared error of saturation prediction of less than eight saturation units, Figure 10. Capillary pressure curves derived from the global scaling factor function are compared with the stress corrected mercury injection curves for six of the plug samples in Figure 11. The match between modelled and measured capillary pressure is excellent for some samples and not quite so good for others, this variation in fit is due to the use of the global scaling factor model/equation from Figure 8. For the limited sample set available the global scaling factor relationship is reasonably successful.

## **APPLICATION OF THE GLOBAL SCALING FACTOR MODEL**

The global scaling factor relationship has been used to model capillary pressure curves and predict water saturations using NMR log data from a 400m section of the carbonate reservoir well. In the MRX NMR log the  $T_2$  bins that represent the smallest depth of investigation were used as these will measure rocks that have been most effected by drilling mud filtrate invasion, i.e. have the smallest gas effect. To model water saturation the following are required: depth of free water level (FWL), brine density, hydrocarbon density, water-hydrocarbon interfacial tension and water-hydrocarbon-rock contact angle. The calculation of the capillary pressure versus depth profile was further complicated in

this well because it has a gas leg. The results of applying the global scaling factor model to the NMR log data are shown in Figure 12, Track 4. The resulting water saturation clearly shows a transition zone water saturation for at least 100m above the free water level. The transition zone water saturation is not seen using the default 100ms  $T_2$  cut-off for carbonates and a SCAL optimised 173ms  $T_2$  cut-off, Tracks 5 & 6. Figure 12 also shows the Archie resistivity model water saturations using core calibrate values for the Archie cementation & saturation exponents. The global scaling factor model water saturations are similar to the Archie values over the whole section, including the transition zone.

## CONCLUSION

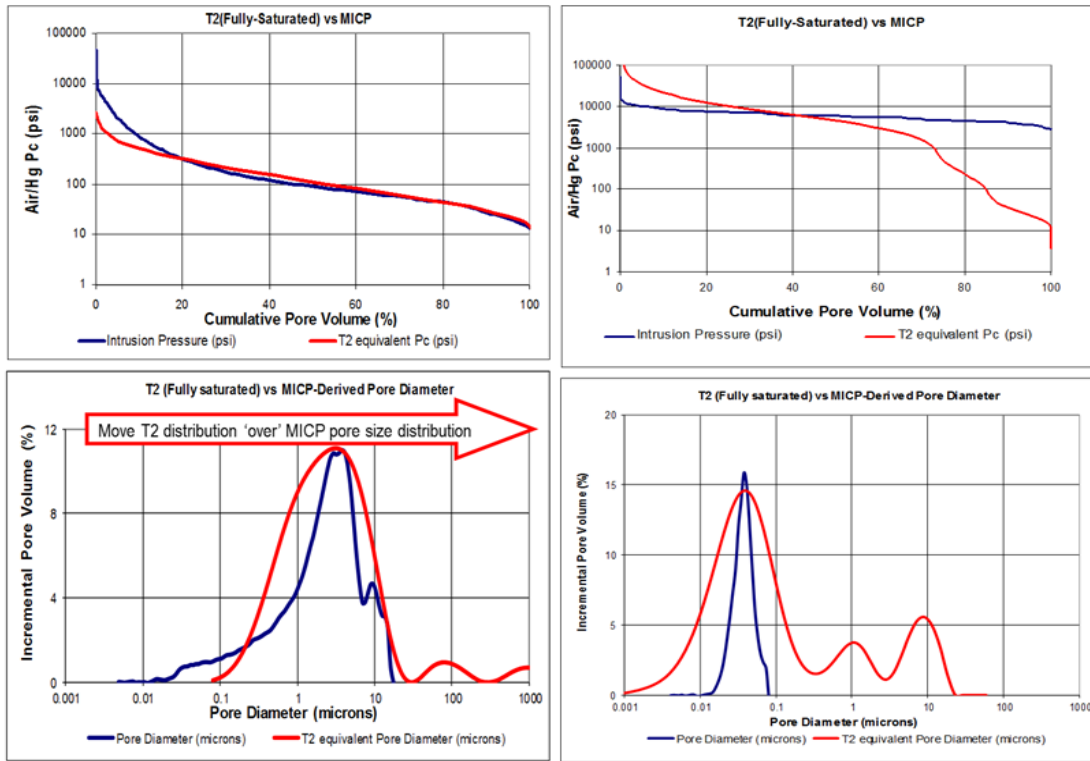
A variable scaling factor model has been derived using core NMR and capillary pressure data. This is used to convert the NMR log data to modelled mercury injection curve at every depth interval. The resulting capillary pressure curves are used to estimate water saturation at each depth. The resulting water saturation compared well with log water saturation from resistivity based models. This model can be used in future wells in the field, which have NMR logs, to obtain a rapid fluid saturation versus depth profile.

## ACKNOWLEDGEMENTS

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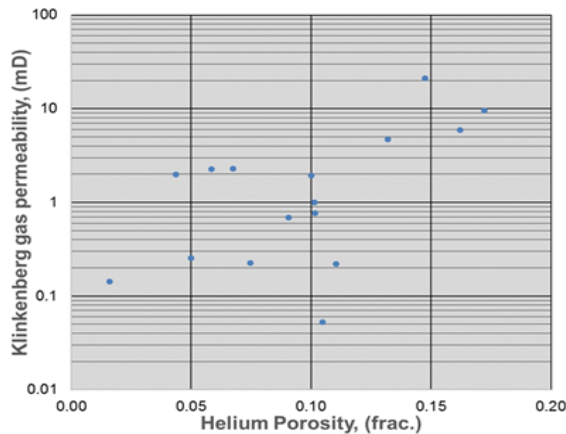
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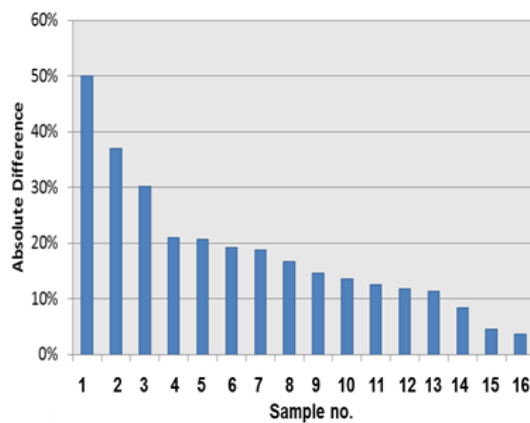


**Figure 1:** Comparison of a sandstone  $T_2$  distribution and mercury injection primary drainage capillary pressure curves using a single scaling factor.  $K_a = 0.8$  mD, Porosity = 19.67%, Scaling factor = 0.8 microns/ms

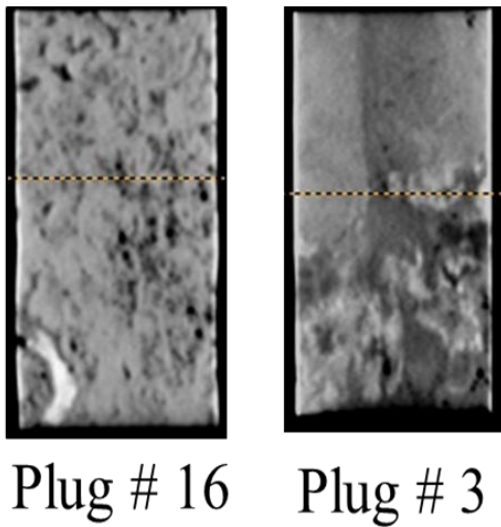
**Figure 2:** Comparison of a carbonate  $T_2$  distribution and mercury injection primary drainage capillary pressure curves using a single scaling factor, showing the effect of pore shielding by smaller pores.  $K_a = 0.01$  mD, Porosity = 4.6%, Scaling factor = 0.006 microns/ms



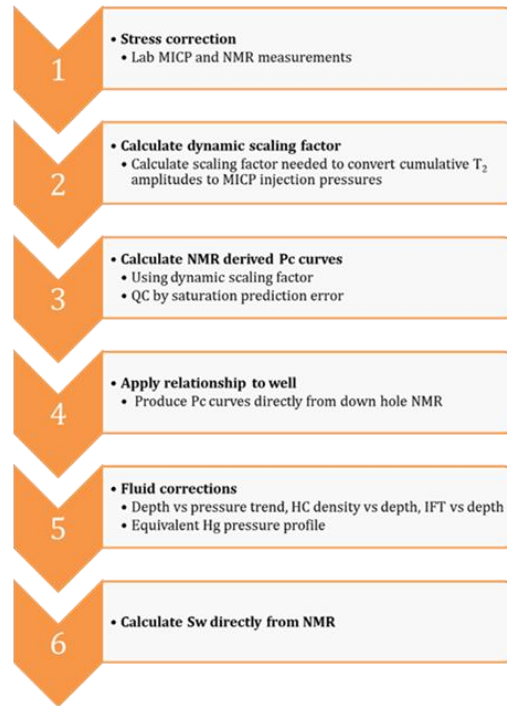
**Figure 3:** Ambient Klinkenberg gas permeability against ambient helium porosity for the clean dry plug samples.



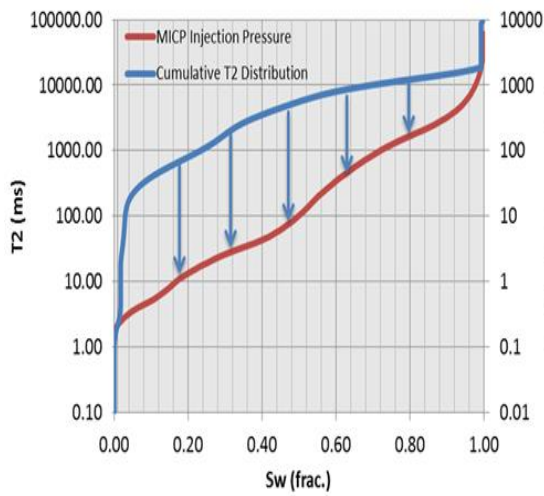
**Figure 4:** Absolute percentage difference between the helium porosity of the mercury injection trim and total porosity of the plug measured using NMR.



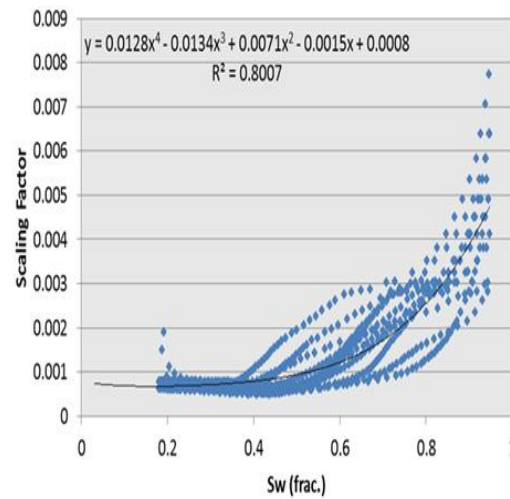
**Figure 5:** CT scan images of plug sample 16 (reasonably homogeneous) & plug 3 (heterogeneous)



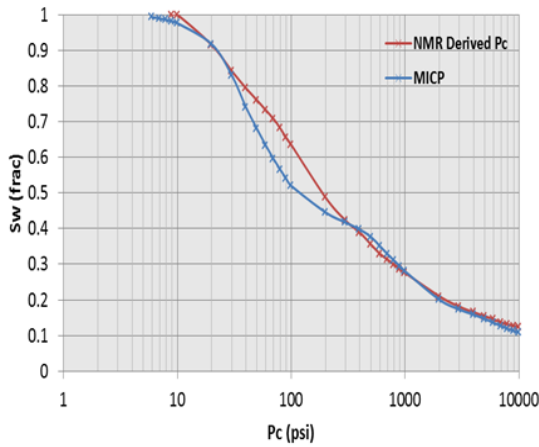
**Figure 6:** NMR derived capillary pressure workflow



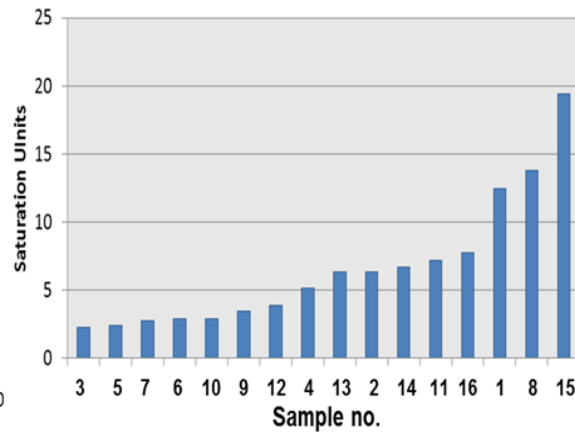
**Figure 7:** This plot demonstrates that it is possible to convert each T<sub>2</sub> time to a given capillary pressure.



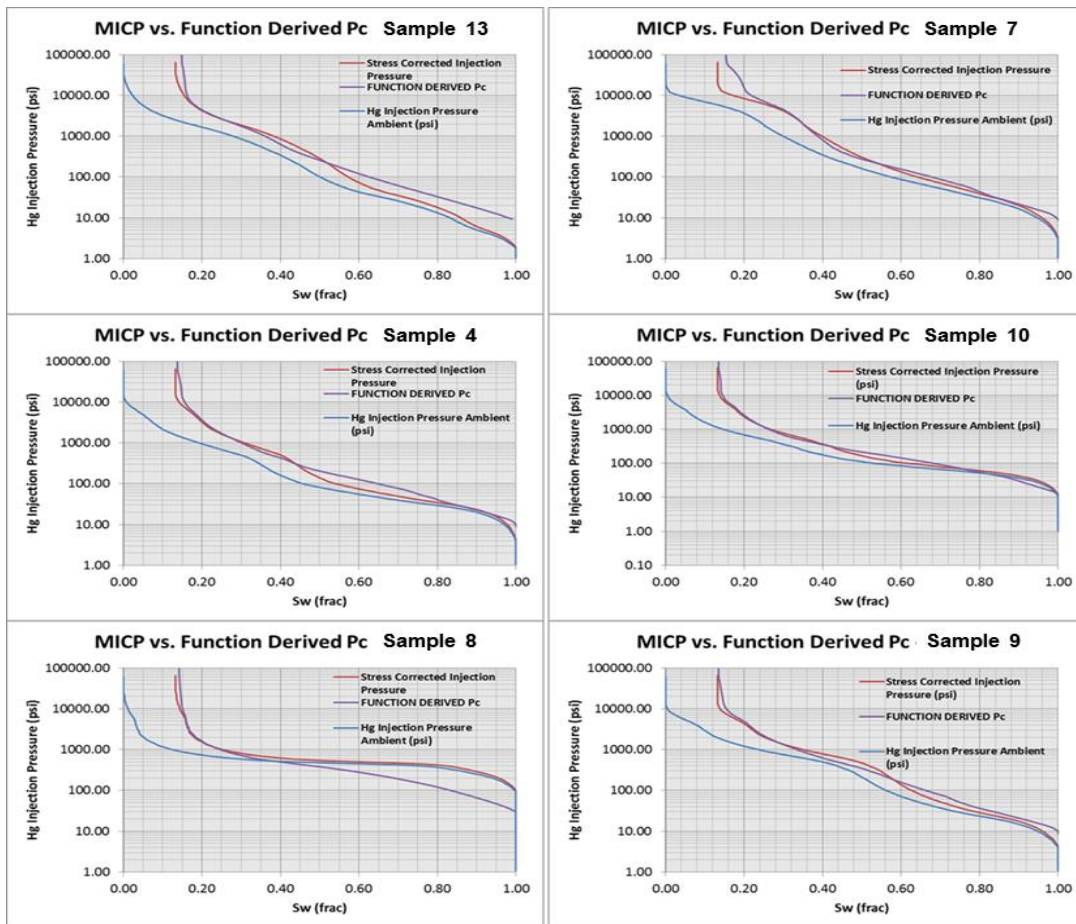
**Figure 8:** The scaling factor versus water saturation with a global polynomial regression, porosity outliers removed.



**Figure 9:** Comparison of the mercury injection capillary pressure curve and the NMR global function derived capillary pressure curve for sample 4.

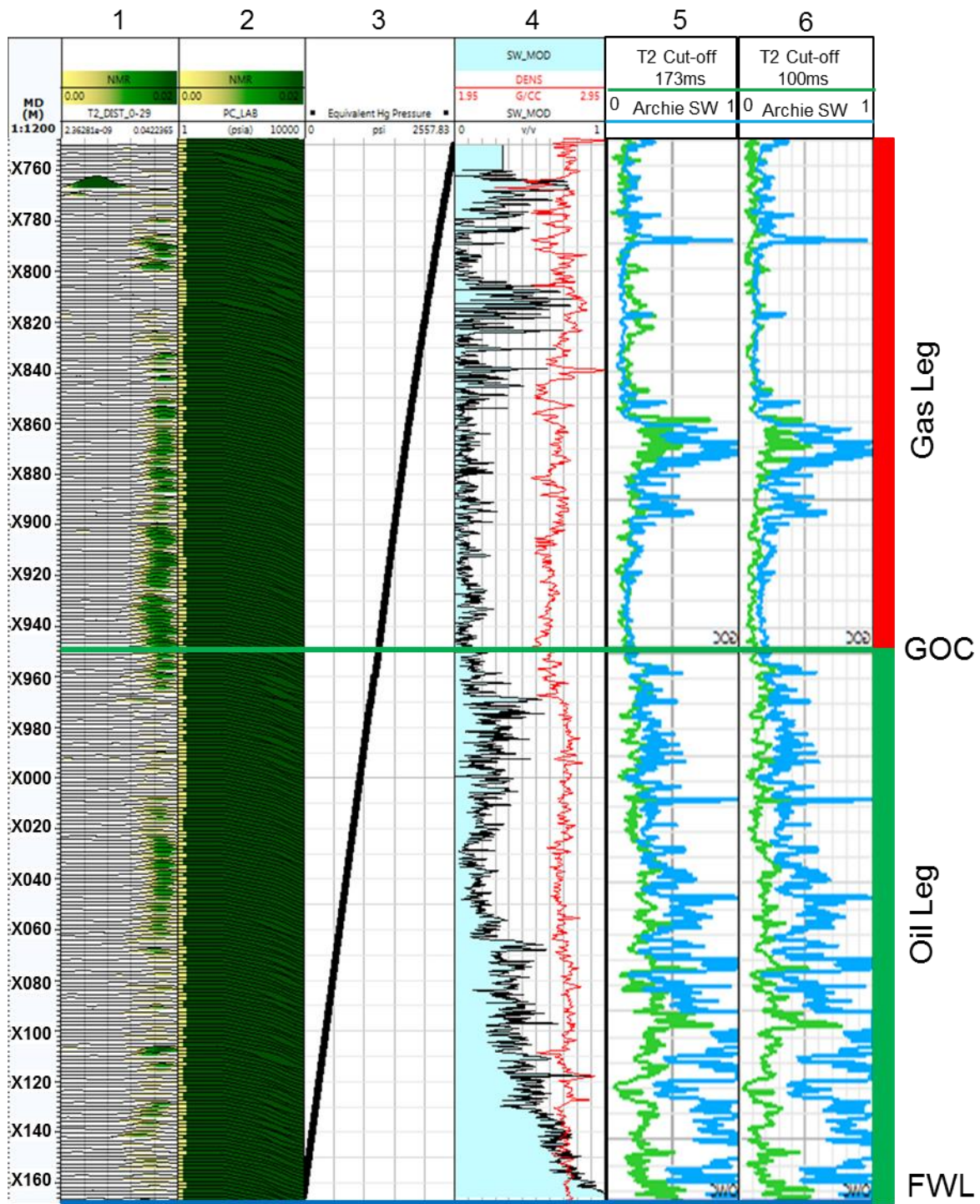


**Figure 10:** Root mean squared error of saturation predictions for all samples.



**Figure 11:** Capillary pressure curves derived from the global scaling factor function (purple curves) compared with the stress corrected mercury injection curves (red curves). The original ambient mercury injection curves are plotted in light blue.





**Figure 12:** Final water saturation log (Track 4, shaded blue) derived using the NMR log & the global scaling factor model. Tracks 5 & 6 show the comparison of the Archie resistivity model water saturation (light blue) and water saturation from the NMR log with a SCAL optimised 173ms T2 cut-off & the default carbonate T2 cut-off of 100ms (green) respectively.