Abstract
Porosity is a key reservoir parameter and high accuracy is needed to properly estimate reserves. But even though there is a long history of porosity measurements and various tools from which to derive it, this can still remain a difficult task. None of the logging tools directly measure porosity but instead respond to density, lithology and fluid. Combining different measurements can help to solve for porosity but also brings the complexity of invasion as all the tools do not have the same radial response. This problem is even more complex when dealing with gas formations as the fluid effect on the measurements is very high.
This paper looks at various methods to improve porosity computations via the integration of Nuclear Magnetic Resonance (NMR) and other porosity measurements in South China Sea gas reservoirs.

Introduction
As illustrated in Fig. 1 - Gas reservoirs in the South China Sea, sand shale sequences with good porosity the gas reservoirs in the South China Sea are composed of sand shale sequences with good porosity. Wells are drilled with oil base mud, invasion is shallow and gas effect is large on the neutron and density measurements. Fig. 1 - Gas reservoirs in the South China Sea, sand shale sequences with good porosity shows a strong neutron-density gas effect and highlights the importance of fluid corrections to obtain reservoir porosity. As gas effect is opposite on the neutron and density measurements, the usual workflow is to compute an apparent porosity from density assuming a water filled rock and then apply a weighted average of this apparent density porosity with an apparent neutron porosity.

Consonant logging
In order to accurately compute porosity and adequately correct for invasion, one needs to integrate measurements that respond to similar volumes of rock. Fig. 2 shows the geometrical responses of density, neutron and two NMR tools. The Combinable Magnetic Resonance (CMR) tool has a single depth of investigation (DOI) while the Magnetic Resonance Scanner (MR Scanner) has three depths of investigation. One can observe that 80% of the density information comes from the first four inches away from the borehole while this same volume represents only 15% of the neutron response. This explains why shallow invasion effects cannot be properly compensated when combining neutron and density measurements, any small variations in the invasion will have different effects on the density and neutron.

NMR is another measurement which can be combined with density to compute porosity. Similar to neutron, NMR reads low in the presence of gas. This is a consequence of gas’ low hydrogen index (HI) and of its hydrogen polarization deficit due to the long longitudinal relaxation time (T1) and the limited acquisition wait time.
A quantitative workflow called Density Magnetic Resonance Porosity (DMRP) combining density and NMR measurements
was developed in 1998 (Freedman et al, 1998). NMR is acquired with short wait time to boost the gas effect (apparent porosity deficit) and total porosity is computed using a weighted average of density derived and apparent NMR porosity. The weights are computed from gas properties and NMR acquisition parameters.

Looking at the radial responses of the various measurements, a better match can be achieved with CMR and density than with neutron and density but it’s still insufficient to obtain a porosity measurement fully compensated for invasion. Very shallow invasion will affect the density and NMR responses differently and the use of a constant weight to compute the porosity will not fully compensate for invasion.

The latest NMR generation tool (MR Scanner) can acquire simultaneous measurements at three depths of investigation from 1.5” - 4” and is similar to density DOI. In terms of DOI, combining this NMR tool with the density allows for consonant logging and therefore the possibility to properly compensate for invasion. This is unfortunately not true for the vertical resolution. MR Scanner vertical resolution is poorer than density resolution and will require additional analysis, as explained later in this paper.

**Porosity computation workflow**

The first approach attempted was to apply the DMRP workflow to the three NMR MR Scanner shells.

The DMRP processing is a weighted average of NMR porosity and density porosity:

\[
DMRP = W \times \text{PORO}_{\text{density}} + (1-W) \times \text{PORO}_{\text{NMR}}
\]  

(1)

\(W\) is a function of gas polarization and HI

The NMR measurement is a discrete measurement and in the case of MR Scanner, each measured volume represents distinct non-overlapping shells with DOI’s of 1.5”, 2.7” and 4” (Fig. 3). From tool radial responses in Fig. 2, one can estimate the weight to apply to each shell to obtain a similar radial response to density.

Equation 1 is now rewritten as:

\[
DMRP = W \times \text{PORO}_{\text{density}} + (1-W) \times (0.4 \times \text{PORO}_{sh-1} + 0.35 \times \text{PORO}_{sh-4} + 0.25 \times \text{PORO}_{sh-8})
\]  

(2)

With:

- \(W\) is a function of gas polarization and HI
- \(sh-1, sh-4\) and \(sh-8\) are the shells measured at 1.5”, 2.7” and 4” into the formation.

**Fig. 4** displays the results of equation 2. We can observe two issues:

- In thick zones and a few feet away from the bed boundaries, the DMRP matches core porosity better than the previously computed density-neutron porosity, but differences remain. A possible cause is the reduced accuracy of the deeper shell measurements due to lower signal to noise ratio (SNR).
- In thin zones or close to bed boundaries, the computed porosity is clearly wrong. This is a consequence of the NMR’s lower vertical resolution compared to density. In order to properly compensate for invasion, we need to combine measurements that investigate the same volume of rock, both radially and vertically.

To address the first point, let’s look closely at the NMR measurement and how the MR Scanner achieves different depth measurements. The permanent magnet in the tool creates a magnetic field which decreases laterally away from the tool. Likewise, the Larmor frequency (spinning of the Hydrogen) also decreases laterally from the tool. By tuning the antenna to lower frequency, we derive a deeper measurement. But there is a drawback, as the magnetic field decreases, less hydrogen is polarized and as the measurement propagates deeper, the antenna signal travels further and becomes more attenuated. This attenuation is compensated via a combination of more antenna power and signal amplification but at a cost of reduced SNR.

**Fig. 5** displays SNR for different shells in the environmental conditions encountered in the reservoirs in the South China Sea. One can observe that shell 1 is good even with low stacking but shell 8 has poor SNR. One can improve SNR via increased stacking but this would result in a decreased vertical resolution, which we wish to avoid.

Via forward modeling, one can examine how reduced SNR affects the measurement.

**Fig. 6** displays a simple fluid model representative of this reservoir. This is a gas reservoir at irreducible water saturation, so the only fluids are bound water, oil-based-mud (OBM) filtrate and gas. The forward modeling computes the tool response for a given fluid model and borehole environment, then NMR inversion is performed.

**Fig. 7** and **Fig. 8** display respectively the results for shell 1 and shell 8. On shell 1, the fluids are well solved for and each fluid volume and total fluid show little statistical variation. Shell 8 however displays large statistical variations. Looking more closely, one can observe that the large statistical variations are mainly on bound water and gas but that the oil volume is
fairly constant and accurate. This is expected; bound water has a fast decay signal and only a limited number of echoes carry the information. Gas signal is small due to under-polarization and low hydrogen index, comparatively SNR is much lower for a gas volume than for a fluid. Conversely, oil is fully polarized with the acquisition sequence used and its signal decays slowly, so the number of echoes useful for processing is high and contributes to an improved SNR.

The poor determination of bound water volume on shell 8 is easy to correct. As it is bound water, it should be the same whatever the depth of measurement, so shell 8 bound water volume can be replaced by the one of shell 1. An alternative is to perform a 4D inversion where the NMR inversion is performed on all the shells simultaneously and using heavier weights for shell 1 measurements sensitive to bound water.

Gas volume measurement is more challenging to improve and would require undesirable levels of stacking. Hence an alternative processing solution is proposed. Instead of solving for an apparent porosity, enable MR Scanner’s fluid typing capability to compute an apparent fluid density. This apparent fluid density can then be used to compute porosity from formation density.

This technique is not new (Minh, 2007). The computed fluid volumes from the three shells were used to compute a fluid density and invasion profile. This was then combined with the radial density response to compute an apparent fluid density in the density measurement volume. However, as observed previously, the gas volume is not accurate on the deep shell so an alternative workflow was developed to avoid propagating the large error of the gas volume to the final porosity computation.

**Improved workflow**

Fig. 9 displays the ideal NMR response for a 30 pu sand. The bound water should be the same on the three shells, the OBM filtrate volume should be equal to or less for subsequent deeper reading shells if a normal invasion profile is assumed and the total porosity measured on each shell is constant. Unfortunately deeper reading shells also have much more statistical variations in fluid volume. Hence only the fluid volumes with good accuracy are used in this processing; that is the shallower shell bound fluid volume and the oil volumes for each shell.

The NMR gas volume is not used as its uncertainty is relatively high, rather the gas volume computed is the difference shell bound fluid volume and the oil volumes for each shell.

Total porosity is the unknown we want to solve for, so we need to perform an iterative processing with the following steps:

1. Start with an initial guess of porosity (PHIT\textsubscript{guess})
2. Use Bound water from shell-1 and consider it constant across the depth of investigation (see Fig. 10)
3. Use oil volume from each shell, then interpolate and extrapolate the oil volume across radial distance with boundary condition (\(V_{\text{bound}} + V_{\text{oil}} < \text{PHIT}\textsubscript{guess}, V_{\text{gas}} > 0\)). (See Fig. 11)
4. Compute fluid density as a function of radial depth (see Fig. 12). Note that the gas density required for this computation is taken from pressure test measurements
5. Apply the density sensitivity function (derivative of the J-function) to the fluid density versus radial distance to compute the apparent fluid density as seen by the density measurement (see Fig. 13).
6. Compute a density porosity using this apparent fluid density and the density measurement (note to be consonant), the density measurement is filtered to the same vertical resolution of the NMR.
7. Iterate until initial guess of PHIT matches with computed porosity

At the end of this iterative processing, we have an apparent fluid density and porosity computed using two tools investigating the same volume of rock. This compensates for any invasion effect but it is still a low vertical resolution result as the density measurement had to be filtered down to the vertical resolution of the NMR.

The last step is to improve the vertical resolution. This is done using alpha processing performed not on the porosity but on the apparent fluid density.

Neutron-density (N-D) crossplot porosity is combined with the density to compute an apparent fluid density. This apparent fluid density has the same vertical resolution as the density tool; it is not accurate due to invasion but it correlates with fluid density to a first order approximation. This is the high vertical resolution measurement for input to alpha processing. The low vertical resolution but accurate fluid density input is derived from the iterative processing of NMR and density. These two inputs are combined in a classic alpha processing technique:

1. N-D apparent fluid density is filtered down to the same vertical resolution as NMR apparent fluid density (Fig. 14, track 6: N-D fluid density non filtered in pink, N-D fluid density filtered in black, NMR fluid density in blue)
2. Alpha correction factor is computed from those two apparent fluid densities
3. The Alpha correction factor is applied to the non-filtered N-D apparent fluid density (Fig. 14, track 7: alpha corrected N-D fluid density in black)

The alpha processing provides a fluid density matching the accuracy of the one computed from NMR but with the vertical resolution of the formation density. A final porosity is then computed from this fluid density and formation density.
Track 8 in Fig. 14 displays the final computed porosity in green. There is now a very good agreement with the core porosity in all zones and the vertical resolution is the same as the formation density measurement.

This technique was tested on a few wells where core data was available and is now used on all wells in the field.

In order to perform this processing in a timely manner, the entire workflow was coded to a software program. Vertical resolution match filtering is handled automatically to ensure alpha processing is properly employed.

This technique can also be applied when the well is drilled with water base mud. In that case the fluid invading the formation is water and this volume will still be properly measured by the NMR. Additionally the software has been coded with a switch to offer an option for both mud systems.

**Conclusion**

The examples seen in this paper highlight the complexity of porosity measurement in gas bearing formations and the importance to properly address the invasion effect. To achieve this, we need to combine tools having similar geometrical response.

In the workflow detailed in this paper, this has been achieved by computing an NMR radial response similar to the density one using the multi depth of investigation capability of the NMR tool, and then handling the vertical resolution challenge by proper filtering and alpha processing technique.

The final porosity computed indeed matches well with the core data.

**Acknowledgements**

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**References**


Fig. 1 - Gas reservoirs in the South China Sea, sand shale sequences with good porosity
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**Fig. 1**
Fig. 2: Geometrical response of various tools

Fig. 3: MR scanner antenna configuration and volume of measurements (shell)
Fig. 4: DMRP processing using the three NMR shells measurements
Fig. 5: Signal to noise ratio as a function of stacking for the different shells

Fig. 6: Fluid model for the simulation
Fig. 7: Modeled response of shell 1 for the fluid model described in Fig. 6

Fig. 8: Modeled response of shell 8 for the fluid model described in Fig. 6
Fig. 9: Expected NMR response profile versus depth of investigation

Fig. 10: Initial guess of PHIT, bound water from shell-1 and oil volume from each shell

Fig. 11: Extrapolation across radial distance with boundary limit (PHIT)
Fig. 12: Fluid density computation versus radial distance

Fig. 13: Sensitivity function of density measurement (J-Der)
Fig. 14: Alpha processing steps and final result