Quantifying Gas Content in Coals Using Borehole Magnetic Resonance

Spencer Summers
Peabody
Brisbane, QLD
SSummers@peabodyenergy.com

Dennis Huo
Peabody
Brisbane, QLD
DHuo@peabodyenergy.com

Tim Hopper*
Qteq Pty Ltd
Perth, WA
thopper@qteq.com.au

Tom Neville
Qteq Pty Ltd
Brisbane, QLD
tneville@qteq.com.au

Benjamin Birt
Kinetic Logging Services
Kewdale, WA
benjamin.birt@kinetic.group

Soumyajit Mandal
Case Western Reserve University
Cleveland, OH, USA
sxm833@case.edu

**presenting author asterisked*

SUMMARY

Evaluating gas content in coals has significant commercial and operational importance. In coal seam gas exploration and development, gas contained in coal seams is the resource of interest. In coal mining, quantifying gas content and evaluating the effectiveness of degassing is essential to safe mining operations.

Traditional approaches to saturation evaluation in conventional oil and gas reservoirs rely on relationships between resistivity and water saturation. These relationships are challenging to apply in coals due to complexities in their pore systems and gas trapping mechanisms. Therefore, geophysical log-based methods are not commonly employed for saturation evaluation, and core canister desorption measurements are the standard approach for gas content evaluation. Desorption measurements present their own challenge due to the unknown and variable volume of gas lost during core recovery, so an in-situ measurement of gas content is desirable.

Advanced magnetic resonance measurements are one method of resistivity-independent saturation evaluation that have been employed in the oil and gas industry for the past approximately fifteen years. However, previous approaches to these types of measurements have focused on the evaluation of conventional reservoirs and hence free gas and oil volumes, and have lacked sensitivity to quantify adsorbed gas, which has a different magnetic resonance response. A novel magnetic resonance acquisition scheme has been developed that provides sensitivity to both adsorbed and free gas, as well as water, allowing for the complete evaluation of fluid content in coal seams. This measurement has been employed in evaluating coal gas content for mining optimisation with encouraging results.

Key words: coal, adsorbed gas, magnetic resonance, well logging.

INTRODUCTION

Evaluating gas content in coals has significant commercial and operational importance. In coal seam gas exploration and development, gas contained in coal seams is the resource of interest. In coal mining, quantifying gas content and evaluating the effectiveness of degassing is essential to safe mining operations.

Gas in coal may occur in two forms, as free gas in the pore system of the coal and as gas adsorbed onto the surfaces of organic matter. As gas increases in a coal, gas molecules will progressively occupy surface adsorption sites until all are occupied and the coal becomes saturated; after this additional gas will occur as free gas in the pore system of the coal. When a coal is depressurised during production, free gas will produce first, and then adsorbed gas will progressively desorb into a free state and be produced as pressure drops.

Many Australian coals, particularly shallower coals being targeted for coal mining, are undersaturated, with all gas in the adsorbed state and the coal pore system being water-filled. Therefore, producing gas from such coals requires producing the water from the pore system of the coals first until the pressure within the coal has declined sufficiently for desorption of adsorbed gas to start. However, deeper coals being targeted for coal seam gas production may be saturated, and shallower coals that are undergoing depressurisation may have started to desorb gas, and so may contain free gas as well as adsorbed gas.

Usual methods for evaluating gas content of coals, such as documented in Australian Standard 3980:2016, focus on evaluating adsorbed gas content by measuring the amount of gas that desorbs from core samples when depressurised (Standards Australia, 2016). The total adsorbed gas content is divided into four fractions, commonly known as Q_1, Q_2, Q_3, and Q_3'. Q_1 represents the unmeasured gas that is lost from the coal sample in the time between drilling of the core sample and the beginning of desorption measurements. Q_2 represents the gas that desorbs from the coal sample at atmospheric conditions. Q_3 represents the gas that further desorbs from the sample at atmospheric conditions after crushing. Q_3' is the remaining gas in the coal that evolves at zero partial pressure. In general, only the Q_2 and Q_3 fractions are measured directly. The Q_1 fraction is, by definition, not measurable and is determined by extrapolation of the

early-time desorption behaviour of the sample. The Q_3' fraction can be measured but is more commonly calculated from adsorption isotherms.

The major source of uncertainty in measuring gas content using desorption measurements is in the Q_1 fraction. This is estimated by extrapolating the early time desorption behaviour of the sample back to a time 0 when desorption started. Uncertainty is associated with the validity of extrapolating the observed early-time desorption behaviour over extended periods, with what model should be used for the extrapolation, with the definition of time 0, and with the impact of temperature variations on the rate of desorption. Additionally, the Q_1 fraction estimated in this manner only represents adsorbed gas that is lost during the sampling process. Any free gas in the coal may also be lost during sampling and sample retrieval, and may not be quantified using these methods.

Given the uncertainty associated with evaluating lost gas fraction in standard gas content measurement approaches, and the inability of these methods to determine free gas content, an in-situ method for evaluating gas content is desirable. The typical approach to evaluating water and hydrocarbon volumes and saturations used in the oil and gas industry relies on formation resistivity measurements and relationships such as Archie's Equation ${S_w}^n = \frac{1}{\phi^m} \cdot \frac{R_w}{R_t}$ (Archie, 1942) that define water saturation S_w as a function of porosity ϕ, water resistivity R_w, formation resistivity R_t and exponents m and n. The porosity exponent m is influenced by the rock's pore geometry and the saturation exponent n is influenced by both the pore geometry and surface effects that may influence the position of different fluid phases at the pore scale. In water-wet rocks with intergranular pore systems, m and n typically show values close to 2. Coals, however, display complex pore geometries, with microporosity associated with organic components in the coal, small-scale cleats, and larger-scale fractures all present. Surface interactions are also complex in coals, with adsorption being the main gas storage mechanism. Therefore, the behaviour of the m and n exponents in coals is poorly understood and the associated uncertainty in resistivity-based saturation estimates in coals is high.

Various other measurements can be used to estimate saturation independently of resistivity. One particularly useful measurement for this application is borehole magnetic resonance (BMR). BMR measurements are directly volumetric, so knowledge of pore geometry parameters such as Archie's m and n exponents is not required, but at the same time they are influenced by both fluid type and properties, so they have the potential to not only evaluate gas content, but also differentiate free gas from adsorbed gas.

BOREHOLE MAGNETIC RESONANCE

BMR takes advantage of interactions between hydrogen nuclei and applied (electro)magnetic fields. Hydrogen nuclei possess both angular momentum and a magnetic moment; simplistically they behave like magnets spinning around their magnetic axes. The rate at which the nuclei spin is a function of the magnetic field strength they are exposed to. In a volume of water, or other hydrogen-containing fluids, the magnetic fields of the various hydrogen nuclei in the different fluid molecules will be randomly oriented. If an external magnetic field is introduced, these nuclei will align themselves with the external magnetic field, or polarise. If the effect of this external magnetic field is then removed, the nuclei will over time dephase, until they are again randomly oriented. Magnetic resonance is specifically sensitive to hydrogen in fluids, as hydrogen nuclei in solids such as coal are not as free to rotate as those in fluids and hence do not participate in magnetic resonance phenomena.

A magnetic resonance measurement consists of two steps (Figure 1). In the first step, an external magnetic field B0 is introduced for a certain period, the wait time or polarisation time. During this period, the hydrogen nuclei align with the B0 field. In the second step, the effect of the external magnetic field is removed. In practice, this is done by applying an electromagnetic pulse at a frequency in resonance with the spin rate of the hydrogen nuclei, tipping the nuclei through 90° into the secondary B1 field plane. As well as effectively removing the influence of the B0 field, this also results in the tipped hydrogen nuclei rotating around the B0 direction and perpendicular to their magnetic axes, or precessing. The precessing hydrogen nuclei generate an oscillating electromagnetic field that can be detected. This rotation rate is governed by the initial spin rate of the nuclei, which is governed in turn by the B0 field strength.

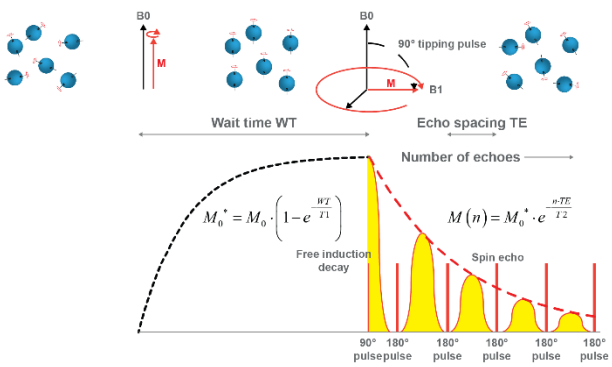

Figure 1: Making a magnetic resonance measurement. Spinning hydrogen nuclei polarise under the influence of an external magnetic field B0, and dephase when the influence of this magnetic field is removed; this is achieved by tipping the nuclei through 90° into the B1 plane using a resonant frequency electromagnetic pulse. While rotating in the B1 plane, the hydrogen nuclei in turn generate an oscillating electromagnetic signal that is measured. Polarisation and dephasing are quasi-exponential processes characterised by time constants T1 and T2.

When all the hydrogen nuclei are precessing in alignment, a peak electromagnetic signal is generated. However, due to local heterogeneities in the B0 field, nuclei will precess at different rates and hence quickly dephase, causing a reduction in the net electromagnetic signal. This process, known as free induction decay, is an experimental artefact and is reversible. Applying an appropriate electromagnetic pulse will tip the nuclei by 180°, effectively reversing the direction of rotation. This will bring the faster and slower precessing nuclei back into alignment, causing a new peak signal, or spin echo, to be generated. By applying a series of 180° pulses at a regular interval, or echo spacing, the precessing nuclei can be continually refocussed.

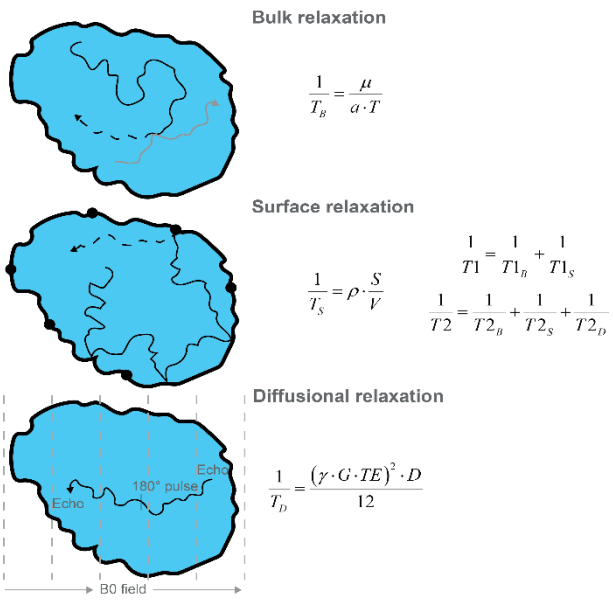

Figure 2: Polarisation (longitudinal relaxation) and dephasing (transverse relaxation) involve two processes, bulk and surface relaxation, occurring in parallel. Dephasing is additionally influenced by diffusional relaxation.

While this is taking place, the hydrogen nuclei are also undergoing irreversible dephasing; this has the effect of moving the axis of rotation of the nuclei out of the B0 direction so that they no longer contribute to the measured signal. Therefore, over time the amplitude of the spin echoes reduces as nuclei undergo irreversible dephasing. Both polarisation and dephasing of the hydrogen nuclei are quasi-exponential processes, with the rate of polarisation described by the longitudinal relaxation time T1 and the rate of dephasing described by the transverse relaxation time T2. The rates at which polarisation and dephasing take place are controlled by interactions between the magnetic fields of the hydrogen nuclei and other local magnetic fields (Figure 2); this includes interactions with the magnetic fields of other hydrogen nuclei in the fluids, known as bulk relaxation, and interactions with magnetic fields generated by paramagnetic atoms such as iron and manganese that may occur in the minerals bounding fluid-containing pores in a rock, known as surface relaxation. Another contributor to dephasing is diffusional relaxation, which takes place when fluid molecules move to areas of differing magnetic field strength during a magnetic resonance measurement, and are therefore not refocussed successfully by applied 180° pulses. Each of these relaxation mechanisms operates in parallel, and so the overall relaxation rate is dominated by the fastest mechanism.

FLUID CHARACTERISATION WITH BOREHOLE MAGNETIC RESONANCE

A single BMR measurement is characterised by a wait time, echo spacing, and total number of spin echoes recorded, and results in the evaluation of a T2 distribution—a distribution of signal amplitudes or fluid volumes associated with different transverse relaxation times. Although the T2 distribution contains useful information related to porosity and pore geometry, fluid types and contents cannot usually be evaluated from a T2 distribution alone. In the case of a coal, which may contain water undergoing surface relaxation at different rates depending on the size of pores it occupies, free gas undergoing a combination of bulk and diffusional relaxation, and adsorbed gas undergoing a combination of bulk and surface relaxation, the T2 responses of these fluids will be overlapping. However, by combining T2 response with T1 and/or diffusion constant, it is possible to differentiate and quantify different fluid phases based on their different properties (Freedman and Heaton, 2004). As these magnetic resonance measurements utilise interactions between hydrogen nuclei and applied (electro)magnetic fields, only hydrogen-bearing fluids such as water and hydrocarbon gases and liquids are detectable. Non-hydrocarbon gases such as carbon dioxide are not detected.

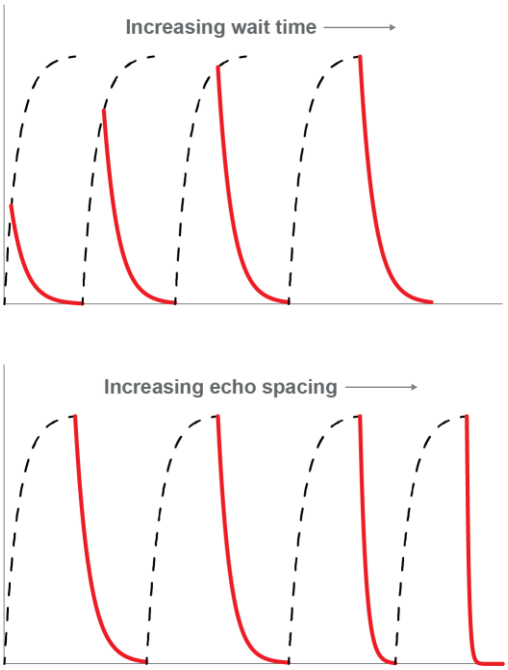

Figure 3: T1 and diffusion constant distributions can be obtained in addition to T2 distributions using combinations of BMR measurements. Varying wait time provides sensitivity to T1, while varying echo spacing provides sensitivity to diffusion constant.

Taking a basic BMR measurement as a starting point, with its defining parameters of wait time, echo spacing, and total number of echoes acquired, multiple BMR measurements can be acquired with selected parameters so that information about T1 and diffusion constant can be obtained in addition to the basic T2 distribution (Figure 3). A series of BMR measurements made with different wait times will sense different amounts of polarisation depending on the relationship between the wait times used and the T1 characteristics of the rock being analysed. By acquiring such a series of measurements and inverting them jointly, both T1 and T2 distributions can be obtained.

Diffusion constant can be investigated by taking advantage of diffusional relaxation and the sensitivity of this mechanism to echo spacing. Longer echo spacings allow more time for molecules to diffuse between refocussing pulses, increasing the amount of dephasing resulting from diffusional relaxation. By acquiring a series of BMR measurements with different echo spacings and inverting them jointly, both T2 and diffusion constant distributions can be obtained.

Sequences of BMR measurements can also be used that involve changes to both wait time and echo spacing. When jointly inverted, these allow T1, T2, and diffusion constant distributions to be evaluated.

ADSORBED GAS QUANTIFICATION

Adsorbed gas acts as a pseudo-liquid membrane, and has a density of 0.6-0.65 g/cm^3 and hydrogen index of 0.6-0.65. It has a low diffusion constant of approximately 10^{-10} m/s^2 although it has a reasonably long T2 (>500 ms), and a high T1/T2 ratio. The combination of low diffusion constant and long T1 and T2 times means that conventional BMR fluid-typing measurements such as T1-T2 and diffusion-T2 using typical pulse sequences are not sensitive to adsorbed gas phases.

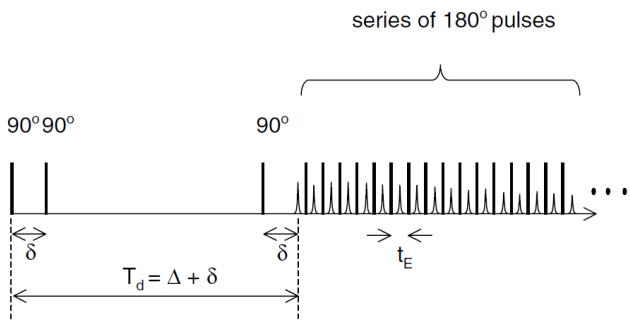

Figure 4: Stimulated echo diffusion editing pulse sequence. The standard 90° excitation pulse is replaced by a composite of three 90° pulses.

In this situation, diffusion encoding using a stimulated echo method provides greater sensitivity to adsorbed gas than probing diffusion using varying echo spacing alone. Diffusion editing pulse sequences are analogous to conventional BMR pulse sequences except for the addition of an initial diffusion encoding segment prior to the sequence of 180° refocussing pulses (Hürlimann and Venkataramanan, 2002). In a stimulated echo pulse sequence, the standard 90° pulse is replaced by a composite of three 90° pulses (Figure 4).

The stimulated echo coherence pathway stores longitudinal magnetisation during the period between the second and third 90° pulses. The magnetisation decays at the longitudinal relaxation rate T1 during this interval, while it decays faster, at the transverse relaxation rate T2, during the intervals between the first and second 90° pulses and between the third 90° pulse and the first 180° pulse. Due to this composite excitation pulse, the irreversible dephasing that occurs during the latter part of the pulse sequence occurs at a rate $T2_{eff}$ that is the weighted sum of T1 and T2. The main advantage of the stimulated echo sequence is that signal decay is relatively slow during the diffusion encoding period, which improves measurement sensitivity for small diffusion constants. To sample a range of diffusion constants, the diffusion encoding time is varied by collecting phase cycled data for several values of time δ while adjusting the value of Δ to keep the total composite pulse time $T_d = \delta + \Delta$ constant, thus varying the time between the second and third 90° pulses. Sixteen part phase cycling is required to select the stimulated echo pathway in the inhomogeneous B0 magnetic fields generated by BMR tools.

For a composite measurement of this type, the signal decay as a function of echo number n and time δ is defined by

$$M(n \cdot t_e, \delta) = \iiint dDdT2_{eff}dT1 f\left(D, T2_{eff}, T1\right) e^{-\frac{T_d}{T1}} e^{-2\cdot\delta\cdot\left(\frac{1}{T2}-\frac{1}{T1}\right)} e^{-(\gamma\cdot G\cdot\delta)^2\left(\Delta-\frac{\delta}{3}\right)} e^{-\frac{n\cdot t_e}{T2_{eff}}}$$

where γ is the gyromagnetic ratio of the hydrogen nucleus and G is the B0 magnetic field gradient (Hopper *et al*., 2017). $f\left(D, T2_{eff}, T1\right)$ represents the three-dimensional relaxation-diffusion distribution function; the quantity of interest. However, it is difficult to invert this integral equation to find $f\left(D, T2_{eff}, T1\right)$. To simplify this expression, the two-dimensional distribution function of spins that survive for time Td can be defined as

$$f_{T_d}\left(D, T2_{eff}\right) = \int dT1 f\left(D, T2_{eff}, T1\right) e^{-\frac{T_d}{T1}}$$

Also, assuming that $\delta << T_d$, then the $e^{-2\cdot\delta\cdot\left(\frac{1}{T2}-\frac{1}{T1}\right)}$ term is negligible compared to $e^{-\frac{T_d}{T1}}$. The signal decay as a function of echo number and time δ can then be simplified to

$$M(n \cdot t_e, \delta) = \iint dDdT2_{eff} f_{T_d}\left(D, T2_{eff}\right) e^{-(\gamma\cdot G\cdot\delta)^2\left(\Delta-\frac{\delta}{3}\right)} e^{-\frac{n\cdot t_e}{T2_{eff}}}$$

This integral equation can be solved to find the function $f_{T_d}\left(D, T2_{eff}\right)$ using standard regularised 2-D Laplace inversion methods.

APPLICATIONS

The pulse sequence described above has been employed with a BMR logging tool to make in-situ measurements of gas content in coal seams. The BMR tool used for these measurements is 2 m in length and weighs 19 kg, and is compatible with standard mining borehole geophysical equipment. Each measurement requires sixteen part phase cycling and eleven values of δ between zero and fifteen milliseconds, for a total of 176 scans. In the example shown here, to improve signal to noise ratio of the acquired data this process was repeated four times and the results averaged, resulting in a total of 704 pulse sequences acquired for a single measurement. For this reason, measurements are made as stations rather than continuous logs, with the BMR tool remaining stationary in the borehole during the time required to make each measurement. Depending on the level of environmental noise and the desired signal to noise ratio, a single station measurement may take between 30 and 240 minutes.

These data are then inverted to find the function $f_{T_d}\left(D, T2_{eff}\right)$, which for ease of interpretation is plotted as a 2-D map of T2 versus diffusion constant (Figure 5). Different fluids will occupy different regions of the diffusion constant-T2 field, so peaks on the 2-D map

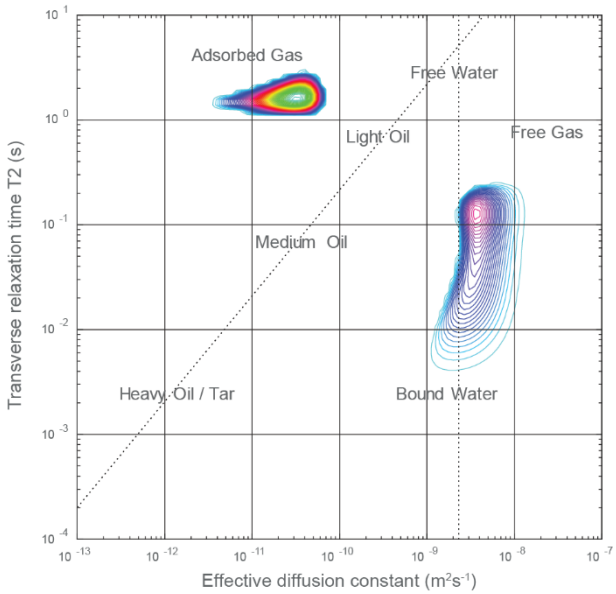

Figure 5: 2-D map of T2 versus diffusion constant. Fluids can be identified and quantified based on peak position and amplitude.

can be identified in terms of fluid type. Additionally, the amplitude of peaks on the 2-D map is a function of hydrogen index, so the downhole volume of each identified fluid can be determined directly. These downhole fluid volumes can then be converted to gas volume at standard conditions per unit mass of coal as is standard for coal gas content measurements.

In the example shown in Figure 5, two peaks are evident. One peak is elongated in the T2 direction at a constant diffusion constant value equal to that of water. This peak represents water occurring in a range of different pore sizes in the coal, therefore exhibiting a range of transverse relaxation rates. A second well-defined peak occurs at a relatively low diffusion constant and long T2 value; this peak is interpreted to represent adsorbed gas. Free gas, if it was present, would occur towards the top-right corner of the 2-D map, with high diffusion constant and long T2.

This example is part of a data set acquired in a six well program, of which two of the wells were cored for desorption gas content measurements. Unfortunately, due to difficulties during coring, only two core gas desorption measurements were acquired over the same intervals as BMR adsorbed gas measurements. These two results are compared in Table 1. The laboratory desorbed gas content is on an "At Sample Ash & Moisture" basis; this is the most appropriate comparison with BMR adsorbed gas measurements that are determined in-situ as a function of the whole coal. Samples are of low-volatile bituminous coal with vitrinite reflectance in the range of 1.5 to 2, and contain ash in the range of 10 to 20 %. Excellent agreement was obtained for one of the samples, while the agreement was not so favourable on the other.

Station	BMR adsorbed gas (m^3/tonne)	Laboratory desorbed gas (m^3/tonne)
1	22.60	14.01
2	16.35	16.39

Table 1: Comparison of BMR and core desorption estimates of adsorbed gas content.

CONCLUSIONS

Gas content in coals is an important quantity for both commercial and operational reasons. Standard methods of evaluating gas content suffer from key limitations due to uncertainty in the amount of gas, both adsorbed and free, that is lost in the period between when the coal is sampled and when the analysis process starts. For this reason, an in-situ method of evaluating gas content in coals is attractive.

2-D borehole magnetic resonance measurements of T2 and diffusion have been used to measure in-situ gas content in coals. Due to the properties of adsorbed gas, standard BMR fluid characterisation methods are not appropriate for this evaluation. A stimulated echo diffusion editing pulse sequence has been defined that provides the required sensitivity to evaluate gas content in coals. Using the difference in T2 and diffusion properties of different fluids in a coal, it is possible to identify and quantify adsorbed gas, free gas, free water, and bound water fractions.

REFERENCES

Archie, G.E., 1942, The electrical resistivity log as an aid in determining some reservoir characteristics. Petroleum Transactions of the AIME, 146, 54-62.

Freedman, R. and Heaton, N., 2004, Fluid characterization using nuclear magnetic resonance logging. Petrophysics, 45, 241-250.

Hopper, T.A.J., Summers, S., Huo, D., Birt, B.J., and Mandal, S., 2017, Borehole magnetic resonance in coal seams. 30th Symposium on the Application of Geophysics to Engineering and Environmental Problems, Denver, Colorado.

Hürlimann, M.D. and Venkataramanan, L., 2002: Quantitative measurement of two-dimensional distribution functions of diffusion and relaxation in grossly inhomogeneous fields. Journal of Magnetic Resonance, 157, 31-42.

Standards Australia, 2016, Determination of gas content of coal and carbonaceuous material—Direct desorption method. Australian Standard AS 3980:2016.