A Comprehensive Review on the Use of NMR Technology in Formation Evaluation

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Abstract

Shortly after its discovery, the Nuclear Magnetic Resonance (NMR) technology has been utilized in various applications in the petroleum industry. Laboratory NMR equipment and wireline logging tools provide essential information about the petrophysical properties of subsurface formations.

The objective of this study is to review briefly the various applications of the NMR technology currently being utilized for formation evaluation purposes and discuss their effectiveness. Furthermore, to adequately understand the type of interpretations that could be made from the NMR measurement, a thorough literature review will be conducted to first understand the physics of the Nuclear Magnetic Resonance measurement and define all its key terms.

The various methods, in which NMR measurements have been utilized in the petroleum industry to evaluate formation properties such as porosity, permeability, identification of multiple fluids in the pore space, oil viscosity and wettability are discussed in this study.

This study shows that the laboratory and field applications of the NMR measurement show a remarkable enhancement in quantifying key parameters such as porosity and permeability. NMR measurement also gives a better understanding of formation fluid types, rock wettability, permeability, and other petro physical parameters that are essential for proper formation evaluation.

Overall, this study concludes that NMR technology has greatly contributed to the enhancement of formation evaluation in the petroleum industry and became an indispensable part of it.

Introduction

Nuclear magnetic resonance has been employed in various scientific disciplines for several decades now, especially in the fields of medicine, physics, and chemistry.

In the petroleum industry, however, this technology was utilized shortly after it was discovered in 1946. NMR measurements were first deployed for testing fluids in porous media in the laboratories oil companies such as Shell and Chevron during the 50’s of last century.

NMR was linked to petrophysical applications when the early endeavors of the researchers showed a clear connection between NMR decay curves and pore size as they repeatedly tested brine-saturated rock sample at different saturation levels. This realization was invested to investigate porosity, permeability, capillary pressure, and other rock properties.
NMR borehole instrumentation is majorly credited to four institutes: Chevron Corporation, Los Alamos National Laboratory, NUMAR Corporation, and Schlumberger Ltd. Huge advancements in NMR logging followed and still are ongoing till the date that made this technology an integral part of the formation evaluation process.

The advances that the NMR tools have undergone added greatly to the confidence in formation evaluation analysis by providing an insight into several key petrophysical properties, such as porosity, permeability, formation fluids, etc. NMR is now an irreplaceable and integral part of formation evaluation [1].

NMR Physics

As its name implies, the principle of Nuclear Magnetic Resonance relies on the response of atoms’ nuclei that are under the influence of a magnetic field (electromagnetic radiation) that is applied at a specific resonance frequency.

Nucleus interactivity with magnetic field is governed by the spin which is a quantum property that pertains to the protons and neutrons that compose the nucleus. Simply put, when the number of protons and neutrons in a given nucleus is even, there will be no spin. If the number of protons and/or neutrons is odd, however, the nucleus will have a spin and, hence, will have a magnetic moment. This magnetic moment enables the nucleus to interact with an externally applied magnetic field producing a measurable signal. Hence, the nuclei of 13C and 35Cl isotopes will have NMR absorption spectra while 18O nucleus will not [2].

Due to their angular momentum, nuclei that have a spin possess a magnetic dipole moment (or quadrupole moment, depending on the electric charges sequence of configuration in the nucleus) and thus will behave in a manner similar to a spinning bar magnet. If the equilibrium of such nuclei is disturbed by a magnetic field, they will exhibit a recessional movement about the static magnetic field in a way similar to that of a gyroscope or a wobbling spinning top around earth’s gravitational field as illustrated in Figure 1.

Although NMR measurement can be made for any nucleus with a non-zero spin, most atoms present in earth subsurface will produce a magnetic signal that is too minute to be detected. Nonetheless, hydrogen nucleus, (which consists of a single proton, with no neutrons) produces the highest response to external magnetic field. Thus, unlike other conventional logging tools, NMR measurement is only responsive to formation fluids (where hydrogen protons are abundant) and not to the formation matrix [3].

Figure 1: Precessional Motion of a hydrogen nucleus around a magnetic field (left) in a similar way to a spinning top (right)

When no external magnetic influence is present, hydrogen protons spin axes are randomly aligned as illustrated in Figure 2. Hence, the first step in NMR measurement is to achieve a unified alignment of the nuclear axes by applying a longitudinal static magnetic field (B₀) around which nuclei will precess with a frequency referred to as Larmor frequency. This alignment process, illustrated in Figure 2, is known as Polarization. Larmor frequency (f) can be calculated using the following equation:

$$f = \frac{\gamma B_0}{2\pi} \quad (= \text{gyromagnetic ratio})$$

Subjecting the nuclei to a magnetic field induces a change in their energy state. Nuclei with precessional axes orientation that is parallel to the direction of the applied magnetic field are in the low-energy state while the ones with axes anti-parallel to the magnetic field are in the high-energy state [4].

The difference between the number of low energy (parallel orientation with B₀) protons parallel and high energy (anti-parallel orientation with B₀) protons represents the bulk magnetization M₀ (net angular momentum per unit volume) which accounts for the signal that NMR tools detect.

The polarization of the hydrogen protons is a gradual process that takes place over a time constant, denoted by the longitudinal relaxation time (T₁). T₁ represents the time needed to achieve 63% magnetization
as illustrated in Figure 3. The equation below shows the relationship between the magnetization value as a function of time ($M_z(t)$) and relaxation time, $T_1$:

$$M_z(t) = M_0(1 - e^{-\frac{t}{T}})$$

Here, $M_0$ represents the maximum value of magnetization that could be reached.

**Figure 2:** Polarization of hydrogen nuclei (protons)

Following the polarization of the hydrogen protons, an oscillating magnetic field $B_1$ is applied in a perpendicular direction to the static field $B_0$ to tip the orientation of the magnetization plane from longitudinal to transverse in order to make the protons precess in phase. This step is referred to as Pulse Tipping. The tipping angle ($\theta$) can be obtained using the following formula:

$$\theta = \gamma B_1 \tau$$

Here, $\tau$ represents the time during which the oscillating field is applied.

**Figure 3:** $T_1$ Relaxation Curve

Optimum pulse tipping is obtained when the oscillating magnetic field $B_1$ is applied at a frequency equal to the Larmor frequency of the targeted nuclei (hydrogen protons in this case). Once the oscillating field ($B_1$) is turned off, the precessional movement of the protons gradually starts to go out of phase. This dephasing, which happens over a very short period, generates a decay signal (usually exponential) that can be detected as illustrated in Figure 4.

**Figure 4:** Dephasing of protons after $B_1$ removal and the decay signal it generates

Dephasing, nonetheless, can be reversed by applying 180° pulse of the oscillating magnetic field $B_1$ that will make the protons precess in phase again and eventually generate a measurable signal that is referred to as the Spin-Echo as demonstrated in Figure 5.

**Figure 5:** Rephasing process through applying the 180° pulse and the generation of a Spin Echo

Repeatedly applying the 180° pulse will generate a train of spin-echoes that form midway between consecutive pulses as Figure 6 shows. After a finite number of rephasing cycles, however, the protons can no longer be refocused due to certain molecular interactions which result in a decaying spin echoes train. The NMR tool measures the
decaying amplitudes of the spin-echoes.

**Figure 6**: A spin-echoes train generated by repeated application of 180° pulse and the decaying behavior it shows with time.

The time constant by which the spin-echoes amplitude exponentially decay is called the transverse relaxation time, $T_2$. An example of $T_2$ relaxation curve is shown in Figure 7. The amplitude of the spin echo at time $t$ (represented by transverse magnetization amplitude $M_x(t)$) can be obtained using the below equation:

$$M_x(t) = M_{0x} e^{-\frac{t}{T_2}}$$

Where $M_{0x}$ is the magnetization at $t=0$.

**Figure 7**: $T_2$ relaxation curve recorded by NMR logging tool representing the amplitude of the decaying spin echoes.

**NMR Applications**

To better understand the reservoir, many logs, such as neutron, density and sonic logs, are used to measure many rock properties such as resistivity, neutron porosity, bulk density, and acoustic velocity. On the other hand, NMR logs offer a significant utility compared to all other logs for many reasons. First, a combination of neutron and density logs are being used to get more information about the porosity of the reservoir rock, which is usually called cross-plot porosity. From this porosity, petrophysicists calculate the effective porosity, which can usually be underestimated or overestimated. For instance, in shaly sand reservoirs, the pore spaces are small and occupied by bound water, which doesn’t allow the migration of hydrocarbons in those pore spaces. Hence, the calculated effective porosity is not efficient because it indicates the existence of hydrocarbons when it is actually bound water that fills the pore spaces.

Second, not only it gives misleading information about the presence of hydrocarbons, the calculated porosity is used, along with other log data, to measure the permeability of the formations. Hence, there is an urge need to make sure that the calculations of the porosity based on the neutron and density logs are correct.

Third, petrophysicists use the cross-over between the neutron and density porosities to indicate the presence of gas or light oil. However, this information may not always be correct. Hence, there is a need to more indications to assume the presence of hydrocarbons. Therefore, NMR logs provide the answer for all these problems by being able to provide information about many petrophysical properties.

**Porosity**

$T_2$ relaxation (decay) data is used to calculate the porosity from NMR logs. So, the NMR porosity corresponds to the response received from hydrogen molecules in the formation which exist only in the fluid-filled pore spaces (whether the fluid is water, oil, or gas). While knowing that NMR is not influenced by the hydrogen in the rock matrix, clay bound water exhibits very short relaxation time, $T_2$, to let the logging tool lose its signal during its dead time [3]. Hence, NMR provides a more direct measurement of porosity than other conventional porosity logs such as neutron and density. This advantage can be used to subdivide the pore space into bound and moveable fluids by looking at the transformed $T_2$ echo data, as shown in Figure 8. This transformation process is done by using a mathematical technique called “inversion.” So, the result obtained from this technique is a semi-log plot of the amplitudes $A(T_2)$ versus $T_2$. This plot is called a $T_2$ distribution and the area under this distribution is...
The second step following the inversion process is to use “cut-off” values. This process generates two or three types of fluids occupying the pore spaces, as shown in Figure 9 for a water-saturated rock. First, Clay-Bound Water (CBW) exhibits a relaxation time of less than 3 or 4 ms. Second, irreducible fluids or capillary bound water exhibit a relaxation time with a range from 4 to 33 ms. Third, movable fluids have a relaxation time of more than 33 ms. It is important to mention that these time values are not static, as they change with different rock types. However, being able to determine the difference between those three fillers of the pore space aids in identifying the effective value of porosity, which is the pore spaces filled with producible or movable fluids. Being able to do so helps in properly reading resistivity logs, as it reacts with all the existing water inside the pore spaces [6].

Moreover, these cut-off values correspond to the location of the fluid on the surface of the rock. For instance, free or movable fluids exist in the large pores of bulk properties that generate a long time. On the other hand, capillary or irreducible fluids are not able to be in contact with the surface of the rock. In water-wet rocks, oil is trapped and restricted to move by the water that is surrounding the grains. Finally, the clay bound water is in contact with the surface of the grains in an extreme way that results in shorter time, as illustrated in the figure. Therefore, what exists above the cut-off value of the irreducible or capillary-bound water is considered the effective porosity of the rock [7].

Although it was previously mentioned that the NMR porosity is not dependent on the type of lithology, petrophysicists have to consider the formation type while analyzing the NMR results. As the amplitude obtained is relative to the number of nuclei that have been polarized, this polarization process is not immediate. It takes many exponential decay function with \( T_1 \). Therefore, there has to be some wait time between NMR measurements to allow the happening of enough polarization to prevent the loss of signal. Therefore, it is crucial to know the type of lithology, either carbonate or sandstone. So, carbonate will require 2.6 seconds as a wait time, as it needs more time for complete polarization. On the other hand, sandstone only requires 1.3 seconds of wait time due to differences in pore sizes.

NMR porosity, however, can be affected by borehole rugosity, hole size, and well deviations, and hence, it can be combined with other porosities to achieve a more refined porosity values. A typical example of combining NMR porosity with other conventional measurements is in gas bearing zones where Density-NMR porosity (DMRP) gives more accurate results than Density-Neutron porosity.

\[
\text{DMRP} = \frac{\text{PHIT}_{\text{max}} \cdot (1 - \frac{(H_f)_{\text{cut}}}{(H_f)}) + \lambda \cdot p_{\text{HTcut}}}{(1 - \frac{(H_f)_{\text{cut}}}{(H_f)}) + \lambda}
\]

Where,

\[
p_{g} = 1 - \exp \left( -\frac{T_{W}}{T_{eg}} \right)
\]

\[
\lambda = \frac{p_{g} - p_{f}}{p_{w} - p_{f}}
\]
Permeability

One of the advantages of using NMR logs is the capability of knowing the real-time permeability, $K_{NMR}$, which is derived from empirical relationships between the NMR porosity and the mean values of $T_2$ [3]. These relationships were established in the laboratory by the use of many core samples. One of the most important equations, which was developed by Schlumberger-Doll Research (SDR) is shown below:

$$K_{NMR} = C(\Phi_{NMR})^4 \left( T_{2(M)} \right)^4$$

Where, $C$ is a constant that varies depending on the type of lithology. If it is sandstone, $C$ is equal to 4, and if it is carbonate, $C$ is equal to 0.1. Also, $\Phi_{NMR}$ is the porosity obtained from the NMR logs, and $T_{2(M)}$ is the logarithmic mean of the $T_2$ distribution.

Another formula, Timur-Coates, depends heavily on the bound and free-fluid fractions of the NMR porosity, which is obtained by the use of the cut-off values for the bound and free-fluids (Logan et al. 1998). This formula, as shown below, is not sensitive to the existence of oil in the $T_2$ spectrum.

$$k = 1000 \left( \frac{\phi_{BF}}{\phi_{FF}} \right)^{\frac{1}{2}}$$

Both equations have proved their efficiency in calculating the permeability in sandstones, while the first formula that employs the logarithmic mean of $T_2$ gives more accurate values. Even in carbonates, it generates precise and accurate results. That is due to two main factors. First, Timur-Coates formula assumes that the existing porosity is the effective porosity. Unfortunately, this assumption is only valid in homogeneous rocks. Second, Timur-Coates formula is delicate to the selection of the $T_2$ cut-off values for the bound-fluid area, while knowing that these cut-off values may change for two reasons. First, these values can be modified depending on a change in paramagnetic ion concentration. Second, an alteration in the capillary pressure of the rock can trigger these cut-off values to change, if the values of the capillary pressure are accurately identified. On the other hand, results obtained from the first formula do not depend on the alterations in the capillary pressure values [8].

Identification of Multiple Fluids in the Pore Space

Another advantage of using a NMR log is the ability to identify multiple fluids in pore spaces, near the wellbore. NMR devices are only capable of measuring data from 1 to 4 in from the walls of the formation while knowing that this area is flushed by the mud filtrate, which is called the flushed zone. However, due to gravity segregation in highly permeable formations, formation fluids are able to invade this flushed area. Therefore, Figure 10 indicates the presence of multiple fluids obtained from the NMR tool by analyzing the different distributions of the relaxation time.

Figure 10: The presence of different fluid phases in a $T_2$ distribution

For water-wet rocks, water will be the fluid that is filling pores of various sizes and, hence, it will present different volumes with a unique value of $T_2$. On the other hand, oil that is present in the bulk volume, which is independent of the formation properties, will indicate a broad range of relaxation time as shown in Figure 10. These results are only dependent on the composition of oil and the temperature of the formation [9].

The NMR functionality of identifying different fluids is the result of a procedure that is called, molecular diffusion. This procedure is simply the random thermal motion of molecules and for each molecule, it can measure the mean square distance that is covered by the molecule per unit of time. The thermal motion of gas and water molecules are usually defined by a single constant. However, for crude oils, since there is a broad range of molecular sizes, a distribution of coefficients exists for their molecular diffusions. Moreover, for lightweight molecules, such as methane and ethane, a molecular diffusion coefficient, $D$, is defined. Hence, NMR tools are capable of using these differences in molecular diffusion for each fluid to generate the water, oil and gas saturations. In more details, there are three procedures that aids in
measuring $T_2$, bulk relaxation, surface relaxation of the wetting-phase fluid, and diffusion relaxation of the signal. Nevertheless, the diffusion relaxation is more important because it depends on the spacing of the radio-frequency pulses, TE, which is an acquisition parameter of the NMR tool. So, it is proportional to the product of DxTE. By recording a set of measurements with diverse TE, water, oil and gas indicate signals that are mitigated due to the diversities of the molecular diffusion coefficient values [5].

**Oil Viscosity**

NMR tools aid the petroleum engineer in determining the oil viscosity by following an established equation, as shown below.

$$
\eta_o = \frac{aT}{T_{2,LM}} f(GOR)
$$

Where is the oil viscosity which is calculated by the NMR tool and $T$ is the temperature of the oil in Kelvin. Also, $T_{2,LM}$ is the logarithmic mean of the $T_2$ distribution and $f(GOR)$ is a function of the Gas-Oil ratio which is dimensionless. Furthermore, $a$ is an empirical constant that is equal to 0.004 (s·cp·K$^{-1}$) for a wide range of different crude oils. In addition to this equation, there is another equation, as shown below, that employs the molecular diffusion coefficient, $D$, that was previously mentioned.

$$
\eta_o = \frac{bT}{D_{LM}}
$$

In this equation, $b$ is a constant that is equal to 5.05 x $10^{-8}$ (cm$^2$·s$^{-1}$·cp·K$^{-1}$). This value is appropriate to use for dead and live hydrocarbon mixtures as well as crude oils. $D_{LM}$ is the logarithmic mean of the $D$ value and it has a unit of cm$^2$/s.

To emphasis on the advantage of estimating oil viscosity by an NMR tool, Figure 11 illustrates a comparison between the results obtained from the NMR tool and the measured value of the viscosity from a viscometer. By using both equations that were discussed in this section, 31 dead crude oils samples were used from the Belridge field in California, and 4 dead crude oils samples were obtained from the Rice University. The oil viscosities that have been achieved by the second equation employing the logarithmic mean of $D$ has an 11.9% of an average absolute percent deviation when compared to the measured values from the viscometer. On the other hand, the oil viscosities that were obtained by the first equation, employing the logarithmic mean of $T_2$, has a 26.8% of an average absolute percent deviation when compared to the measured values from the viscometer [10].

**Wettability**

Wettability is a measure of the tendency of one fluid to adhere, or spread over, rock surface containing two or more immiscible fluids. Different types of wettability may occur in reservoir rocks, depending on the oil-brine-surface interaction. These types include formations that is strongly oil-wet, neutral, strongly water-wet or mixed wet, where wettability change in the same rock depending on the pore size. Wettability measurement is expected to vary across the reservoir and with time, as oil is produced and saturations change. Even though understating rocks wettability is critical for estimating reservoir potential and selecting its development plan, it is considered one of the big uncertainties in many fields [11].

Determining wettability using NMR is much cheaper than traditional laboratory methods and provides equally accurate results without intervening in fluids’ saturation. Further it can be implemented in-situ to, for example, monitor real-time changes in wettability over the entire pay interval.

Wettability can be determined from NMR logging tools using the spin-lattice, transverse, relaxation times
(T2). Liquids near solid surfaces tend to have smaller diffusion coefficient, compared to its bulk phase, due to the stronger intermolecular forces present between the surface and the liquid. This surface-liquid interaction leads to longer relaxation times due to the creation of an additional relaxation mechanism called surface relaxivity [10, 12, 13].

Completely water wet rocks have no oil in contact with the rock surface; therefore the NMR relaxation times will not be different from that of its bulk phase, i.e. it will not have the additional surface relaxation mentioned above. On the other hand, rocks that are not completely water wet holds oil in contact with some of its solid surface; thus oil relaxation times will be affected by the surface relaxivity. The significance of this effect depends on the fraction of the rock wetted by oil. The NMR wettability index, INMR, in the equation below, uses this concept to quantitatively express the fraction of rocks wetted by water. In this equation SW_w and SW_o are the surfaces wetted by water and oil respectively. Similar to traditional laboratory-based wettability indices, Amott and USBM, the NMR wettability index is scaled from +1 for strongly water wet, 0 for neutral, to -1 for strongly oil wet [14, 12].

\[
I_{NMR} = \frac{SW_w - SW_o}{SW_w + SW_o}
\]

The limitation of using this method is that it requires the oil peak to be distinguishable in the T2 distribution; which is only true if oil saturation is very high and if the oil has low viscosity. Wim J. Looyestijn & Hofman [13] believe that this limitation could be overcome by inversion of a forward model of the obtained NMR data; while taking into account the T2 distribution of bulk fluids and the rock at SW = 1, the wetting fraction, and the microscopic disruption of water and oil. Figure 12 shows the effect of different wettability indices on modeled oil and water NMR responses. Figure 12

Using the Looyestijn & Hofman [13] forward model faces some challenges when it comes to field implementation. These include the fact that mud invasion will significantly disturb the results whether it was water and oil based mud. Also, T2 distribution of the rock at SW = 1 is not usually available and must be inferred, and oil’s in-situ viscosity and GOR must be known to be able to model its T2 distribution.

Conclusions

This paper presented the importance of employing an NMR tool to determine and analyze the petrophysical properties of any reservoir formation. This unique logging tool depends on the principle of the response of the nuclei of atoms after being subjected to a magnetic field with a definite resonance frequency. The NMR technology is able to surpass many conventional logging tools in achieving the goals of the formation evaluation studies by giving more accurate information. Through this paper, NMR logging tools demonstrated the capability to measure porosity, through the use of cut-off values, and to identify the presence of water, oil and gas better.
than the combination of neutron and density logs that are being used in conjunction to estimate the rock porosity and detect the presence of gas. In addition, by following a set of established equations, the NMR tool has proven its effectiveness in calculating the permeability of the rock and the oil viscosity which have a great importance in the petroleum industry. NMR logs could also be a great alternative to the laboratory-based methods to determine rock wettability. Hence, this paper gives an oversight of the field applications of the NMR tools, which have a promising future in enhancing the formation evaluation studies to successfully analyze the reservoir formations.

References