Characteristics of the nuclear magnetic resonance logging response in fracture oil and gas reservoirs

Lizhi Xiao¹ and Kui Li
State Key Laboratory of Petroleum Resources and Prospecting, China University of Petroleum, Beijing 102249, China
E-mail: xiaolizhi@cup.edu.cn

New Journal of Physics 13 (2011) 045003 (12pp)
Received 30 July 2010
Published 4 April 2011
Online at http://www.njp.org/
doi:10.1088/1367-2630/13/4/045003

Abstract. Fracture oil and gas reservoirs exist in large numbers. The accurate logging evaluation of fracture reservoirs has puzzled petroleum geologists for a long time. Nuclear magnetic resonance (NMR) logging is an effective new technology for borehole measurement and formation evaluation. It has been widely applied in non-fracture reservoirs, and good results have been obtained. But its application in fracture reservoirs has rarely been reported in the literature. This paper studies systematically the impact of fracture parameters (width, number, angle, etc), the instrument parameter (antenna length) and the borehole condition (type of drilling fluid) on NMR logging by establishing the equation of the NMR logging response in fracture reservoirs. First, the relationship between the transverse relaxation time of fluid-saturated fracture and fracture aperture in the condition of different transverse surface relaxation rates was analyzed; then, the impact of the fracture aperture, dip angle, length of two kinds of antennas and mud type was calculated through forward modeling and inversion. The results show that the existence of fractures affects the NMR logging; the characteristics of the NMR logging response become more obvious with increasing fracture aperture and number of fractures. It is also found that $T_2$ distribution from the fracture reservoir will be affected by echo spacing, type of drilling fluids and length of antennas. A long echo spacing is more sensitive to the type of drilling fluid. A short antenna is more effective for identifying fractures. In addition, the impact of fracture dip angle on NMR logging is affected by the antenna length.

¹ Author to whom any correspondence should be addressed.
1. Introduction

Fractures normally develop well in carbonate and igneous rocks and can also be found in sandstones. Fracture types in the formation include network fractures, oblique fractures, vertical fractures, half-filling fractures and induced fractures. Fractures play a very important role in oil and gas recovery. Fractures could connect isolated vugs, which may generate an effective reservoir space. They may also be conducive to the secondary transformation of reservoirs [1, 2]. Identifying and evaluating fractures have always been important tasks in well logging.

It is known that nuclear magnetic resonance (NMR) logging provides lithology-independent porosity and $T_2$ distributions. $T_2$ distribution is a starting point for further interpretation and evaluation of NMR logging, and it contains a variety of information about the fluids in the pore and in the matrix. From $T_2$ distribution, one can derive the porosity, permeability and pore size distribution, which are essential for formation evaluation [3]–[9].

Figure 1 shows examples of NMR logging in fracture reservoirs. In figure 1(a), the zone of interest is between 3590 and 3600 m, and was identified as a gas-bearing formation from mud logging data. In figure 1(b), the zone of interest is from 3599.6 to 3607.4, and mud log measurements show an exception. Both of them are well-developed fracture zones, as shown by formation microimaging (FMI; right side on each). Although their $T_2$ distributions of NMR logging did not show a direct relation to fractures, at some depths, the $T_2$ value is small, which reflects bound fluids, whereas at some other depths, the $T_2$ value is large, which normally reflects movable fluids, from either large pores or fractures. It is necessary to study the characteristics of the NMR logging response of fracture reservoirs. To date, the study of NMR in fracture reservoirs is rare; it has been mentioned and analyzed qualitatively in three articles [10]–[12]. Yoshito and Tsuneo [13] proposed a method for estimating fracture apertures using NMR logging. It was pointed out based on the relation between the $T_2$ of fluids in reservoirs and fracture apertures that if the fracture aperture is greater than 0.2 mm, then one could use NMR logging (free fluid porosity data) to evaluate fractures quantitatively, and determine the linear relationship between the free fluid porosity and fracture aperture by calibrating the NMR sensor in the laboratory. In the same study, fractures in a Holocene andesitic lava were evaluated quantitatively using NMR logging, electrical micro imaging (EMI, trademark of Haliburton Energy Services) and neutron logging data comprehensively, which was the first quantitative evaluation of fractures using NMR logging, but there was no discussion of the effects of NMR logging on fracture reservoirs. We present here a thorough study of the NMR logging response...
at fracture reservoirs and investigate whether the fracture parameters, borehole conditions and sensor parameters will affect the NMR logging response.

2. Response equation

The sensitive zone for an NMR logging sensor will depend on the length of its antenna. For Magnetic Resonance Imaging Logging (MRIL; trademark of Halliburton Energy Services), the length of antennas is 24 inches. If the tool does not move during the measurement cycle (i.e. a stationary reading is obtained), the vertical resolution equals the length of the antennas. Figure 2(a) shows the detection region, marked by a blue line. The sensitive volume is a thin cylindrical shell with 24 inches height and 1 mm thickness. Fractures cross the cylindrical shell by a certain width and angle and form an inclined cylindrical shell (the cylindrical shell is vertical when the dip angle is 0), as shown in figure 2(b); the relaxation time of the fluid-saturated fracture will vary with fracture parameters (apertures, number and dip) and type of fluid in the fracture.

There are three relaxation mechanisms for fluids saturated in reservoir rocks: surface relaxation, bulk relaxation and diffusive relaxation. Without taking into account the impact of
Figure 2. The detection region of NMR logging (a) and the distribution of fractures in the detection region (b).

Figure 3. $T_2$ values as a function of fracture aperture with different surface relaxivities.

diffusion, the transverse relaxation time $T_2$ of the fluid in fractures can be expressed as

$$\frac{1}{T_2} = \rho_2 \left( \frac{S}{V} \right) + \frac{1}{T_{2b}},$$

(1)

where $\rho_2$ is the surface relaxivity of the fracture. Paramagnetic irons in rocks will yield a high magnetic susceptibility and increased $\rho_2$ value. Here, $S/V$ is the surface-to-volume ratio of the pore space, and $T_{2b}$ is the $T_2$ of bulk fluid.

For a planar fracture with aperture $d$, $S/V$ is $2/d$. Therefore, equation (1) can be replaced by equation (2),

$$\frac{1}{T_2} = \rho_2 \left( \frac{2}{d} \right) + \frac{1}{T_{2b}}.$$

(2)

Figure 3 shows the relationship between $T_2$ of the fluid-saturated fracture and fracture aperture with different transverse surface relaxivities. We assume that $T_{2b}$ of the drilling fluid filtrate equals 2 s. The study assumes that no solid particles enter the fractures; hence the drilling fluid filtrate signature is considered.
If the matrix porosity, fracture aperture and dip are known, then the volume and porosity of the fracture in the detection region can be estimated. The volumes of the thin cylindrical shell and the inclined cylindrical shell are given by equations (3) and (4),

\[
V = \int_{r_1}^{r_2} L \cdot 2\pi r \, dr, \quad (3)
\]

\[
V_f = \int_{r_1}^{r_2} \left( \frac{d \cdot 2\pi r}{\cos \theta} \right) \, dr, \quad (4)
\]

\[
\phi_f = \frac{V_f}{V}, \quad (5)
\]

\[
\phi_b = \phi_m \cdot (1 - \phi_f), \quad (6)
\]

where \(L\) is the length of antennas, \(r\) is the radial detection depth, \(\theta\) is the fracture dip, \(d\) is the fracture aperture, \(\phi_f\) is the fracture porosity, \(\phi_m\) is the matrix porosity without fracture and \(\phi_b\) is the matrix porosity when fractures exist in the detection region.

The response function of NMR logging in the fracture reservoir can be expressed as

\[
\text{ECHO} = \sum_{i=1}^{N} \phi_1\text{HI}_{\text{fluid}} \left(1 - \exp\left(-\frac{T_w}{T_{1,\text{pore}}(i)}\right)\right) \left(\exp\left(-\frac{t}{T_{2,\text{pore}}(i)}\right)\right)
+ \sum_{i=1}^{M} \phi_2\text{HI}_{\text{fluid}} \left(1 - \exp\left(-\frac{T_w}{T_{1,\text{fracture}}(i)}\right)\right) \left(\exp\left(-\frac{t}{T_{2,\text{fracture}}(i)}\right)\right) + \text{noise}, \quad (7)
\]

where \(N\) is the bin number for pore size components, \(M\) is the number of fractures, \(\text{HI}_{\text{fluid}}\) is the hydrogen index of the fluid, \(T_{2,\text{pore}}\) is the transverse relaxation time of the fluid in the pore and \(T_{2,\text{fracture}}\) is the transverse relaxation time of fluid-saturated fractures.

The first part of the equation is the NMR logging response to pores and the second part is to fractures’ response. It can be seen that the response of NMR logging in the fracture reservoir is affected by many factors, such as matrix porosity, fracture porosity, type of fluid, \(T_1\), \(T_2\), which are controlled by fracture parameters (aperture, number and dip), type of fluid and the length of antennas.

Based on the equation, an echo train can be produced by forward modeling plus random noise, and then \(T_2\) distribution can be inverted from the echo train.

3. Analysis and discussion

Assuming that the fracture is planar, the dip is 0°, 45° and 90° separately and the fracture aperture is 0.1, 0.5, 1, 10 and 20 mm; the types of drilling fluids include water-based and oil-based. Matrix porosity, fracture porosity and \(T_2\) for fluid-saturated fracture could be calculated by using equations (2)–(6) with different parameters, drilling fluids and lengths of antennas. The magnetic gradient is given as \(18 \times 10^{-4}\) T cm\(^{-1}\) and MRIL is used. It is further assumed that formations exist in only two kinds of reservoirs: small pores and fractures, rock is hydrophilic, \(\Phi_m = 5\%\), \(T_{2b} = 1\) s, the length of antennas is 24 inches, and the detection region exists in a single fracture. As shown in table 1, \(T_2\) values become higher and higher with increasing fracture aperture when a water-based drilling fluid is used, but do not depend on the fracture aperture when an oil-based drilling fluid is considered.
Table 1. Matrix porosity, fracture porosity and $T_2$ of fluid-saturated fractures with different fracture apertures, dip angles and drilling fluids

| Dip $\theta$ (°) | Fracture aperture $d$ (mm) | Fracture Matrix Fracture $T_2$ (ms) fluid-saturated fracture | Water-based | Oil-based |
|------------------|-----------------------------|--------------------------------|--------------|-----------|
|                  | $\phi_h$ (%) | $\phi_f$ (%) | $T_2$ |                   |            |
| 0                | 0.1 4.99    | 0.02 47.61 | 47.61 | 769.20 |                |
|                  | 0.5 4.99    | 0.08 200   | 200  | (TE = 0.9 ms) |            |
|                  | 1 4.99      | 0.16 333.33 | 333.33 | 623.40 |            |
|                  | 10 4.91     | 1.64 833.33 | 833.33 | (TE = 1.2 ms) |            |
|                  | 20 4.84     | 3.28 909.09 | 909.09 | 271.04 |            |
| 45               | 0.1 4.99    | 0.02 47.61 | 47.61 | 139.58 | (TE = 2.4 ms) |
|                  | 0.5 4.99    | 0.12 200   | 200  | (TE = 3.6 ms) |            |
|                  | 1 4.98      | 0.23 333.33 | 333.33 | 83.13 |            |
|                  | 10 4.88     | 2.32 833.33 | 833.33 | (TE = 4.8 ms) |            |
|                  | 20 4.77     | 4.64 909.09 | 909.09 | 54.69  | (TE = 6 ms) |
| 90               | Fracture is in the slice | 2 4.97 | 0.48 500 | 500 |            |
|                  | Fracture is not in the slice | 2 5 0 | – | – |            |

3.1. Impact of fracture aperture

From equation (2), the transverse relaxation time of fluid-saturated fracture will change with fracture aperture. From table 1, when the fracture aperture increases, the matrix porosity decreases and the fracture porosity increases.

Figure 4 shows the characteristics of the NMR logging response in the detection region using a water-based drilling fluid, where the transverse relaxation time and hydrogen index of the drilling fluid filtrate is 1 s and 1, respectively, and $T_w = 12$ s, $TE = 1.2$ ms, $L = 24$ inches. Different apertures of fractures are given as 0.1, 0.2, 0.5, 0.8, 1, 2, 3, 4, 5, 10 and 20 mm. The $S/V$ for each fracture is calculated by $2/d$.

As shown in figure 4, when the fracture aperture $d$ is equal to 0.1 or 0.2 mm, the $T_2$ distribution is the same as when there is no fracture. When the fracture aperture is equal to or greater than 2 mm, bimodal distributions appear on the $T_2$ spectrum; with increasing fracture aperture, the peak of the $T_2$ distribution becomes larger gradually.

In a network-fracture or oblique-fracture formation, an NMR sensor will detect more fracture signals.

Figure 5 shows $T_2$ distributions when the formations exist in a single or two fractures (assuming the two fractures are spaced apart by 2 mm). Here, the total width of two fractures is equal to the width of a single fracture. Their $T_2$ distributions are basically the same. From equation (2) it is seen that the $T_2$ values of a single fracture with an aperture of 2 mm and two fractures with an aperture of 2 mm are different, but when the fracture aperture is small, the fracture porosity is accordingly small, so its effect could be ignored. Therefore, when the fracture aperture is very small, the impact of porosity on NMR logging is dominant.
3.2. Impact of dip angle

When the dip angle of the fracture changes, the volume of fracture in the slice will change; according to equation (4), fracture porosity changes accordingly; when the fracture dip is too large, the fracture will not fully appear in the detection area owing to the thickness of the NMR slice, such as vertical fractures (with a dip of 90°). Therefore, it is necessary to consider two cases: whether the vertical fracture is in the slice or is not in the slice. After calculating, we could see that when the fracture dip is 0° and 45°, respectively, the reservoir matrix porosity and fracture porosity vary in the range of 0–0.1% and 0–1.36% at several fracture apertures, which illustrates that the impact of the change in dip angle on the NMR logging is not obvious when the aperture of the fracture is small, but becomes increasingly obvious with increasing fracture aperture. Here we test the shape of the $T_2$ spectrum with variation of dip angle when the fracture aperture is equal to 2 mm.

Figure 6 shows six cases: the dip angle of the fracture $\theta$ equals 0°, 15°, 30°, 45°, 60° and 90°, respectively. We can see that the change in $T_2$ distribution with dip angle is not obvious when the fracture aperture equals 2 mm.

3.3. Impact of drilling fluids

The small pores are hydrophilic. When the drill fluid filtrate invades into the formation, the pores in the flushed zone fractures will fill with filtrate completely. Typical drilling fluids include water-based drilling fluid, oil-based drilling fluid and gas drilling. Different drilling fluids have
different hydrogen indexes, diffusion coefficients and transverse relaxation times due to their different densities and viscosities. Any change in parameters in equation (7) may affect the response of NMR logging. When the diffusion coefficient of the drilling fluid filtrate is large, the effect of diffusion relaxation could not be ignored, and equation (2) should be written as

$$1/T_{2d} = \rho_2 \left(2/d\right) + \left(1/T_{2b}\right) + \frac{D_f (r \text{GTE})^2}{12},$$

Figure 5. NMR $T_2$ distributions of the detection region with different fracture apertures: (a) single fracture; (b) two fractures.

Figure 6. $d = 2$ mm, $T_2$ distribution with different dip angles: (a) using water-based drilling fluid, the sensor coincided with the vertical fractures; (b) using water-based drilling fluid, the sensor did not coincide with the vertical fractures.
where $G$ is the magnetic gradient of the static magnetic field produced by the NMR logging tool and $TE$ is the echo spacing.

Here, $T_2f$ is the transverse relaxation time of the fluid-saturated fracture, $D_f$ is the diffusion coefficient of the drilling fluid filtrate, and $T_{2b}$ is the bulk relaxation time, which is related to the temperature and viscosity of the drilling fluid filtrate.

As mentioned in table 1, the $T_2$ distribution of the fracture reservoir changes obviously with fracture aperture when a water-based drilling fluid is used, but does not change when an oil-based drilling fluid is used.

Figure 7 shows $T_2$ distributions for different types of drilling fluids, where TE = 1.2 and 6 ms, respectively, and the magnetic field gradient is $18 \times 10^{-4} \text{T cm}^{-1}$ with MRIL. It can be seen that when the echo spacing is short, $T_2$ distributions are very close for both water-based and oil-based drilling fluid filtrates. When the echo spacing is long, $T_2$ distributions are different. The diffusion coefficient of the oil-based drilling fluid filtrate is normally greater than that of the water-based drilling fluid filtrate. The $T_2$ values of the fluid filtrate within fractures become smaller with increasing echo spacing (figure 8), which caused the information about fractures and small pores to overlap.

Figure 8 shows the $T_2$ distribution with different echo spacings, where the fracture aperture is 2 mm (left) and 20 mm (right) with a dip angle of 0 and an oil-based drilling fluid was used. The $T_2$ distribution becomes narrow with increasing echo spacing. The $T_2$ distribution has no
Figure 8. $T_2$ distributions at oil-based drilling fluid with different echo spacings and fracture apertures: $d = 2\text{ mm}$ (a) $d = 20\text{ mm}$ (b).

information about fracture when the echo spacing is greater than 3.6 ms. Therefore, if one wants to detect fractures using NMR, echo spacing has to be planned very carefully.

### 3.4. Impact of antenna length

From equations (3)–(6), we see that the fracture porosity and matrix porosity will increase as the antenna length decreases. The parameters are: echo spacing $TE$ is equal to 1.2 ms; the fracture aperture $d$ is equal to 0.05, 0.1, 0.2, 0.5, 0.8, 0.9, 1, 1.2, 1.5, 1.8 and 2 mm, respectively; the fractures are filled with a water-based drilling fluid filtrate; the antenna length is 24 and 6 inches, respectively; the magnetic field gradient is $18 \times 10^{-4} \text{T cm}^{-1}$; the simulated and inverted $T_2$ distribution in the fracture reservoir is shown in figure 9; the 6 inch antenna gets a higher vertical resolution than the 24 inch one; when $d$ reaches 0.8 mm, the $T_2$ distribution contains fracture information.

Figure 10 shows the impact of dip angle on $T_2$ distribution. The effect is not so obvious when $L$ equals 24 inches but is obvious when $L$ equals 6 inches.

### 4. Conclusions

Through theoretical analysis and numerical simulation, it can be concluded that NMR logging has a clear response at fracture reservoirs and is associated with many factors, such as fracture aperture, fracture number, fracture dip angle and drilling fluids.

1. If the fracture aperture increases, the $T_2$ of a fluid-saturated fracture will also increase correspondingly. The larger the fracture aperture, the more obvious the response of NMR logging.
2. With increasing fracture aperture, the peak of $T_2$ distribution gradually increases. The NMR logging response at the fracture becomes more obvious as the number of fractures increases.
3. The drilling fluid filtrate will affect the response of NMR logging. For different drilling fluid filtrates with the same fracture parameters, the shape of $T_2$ distribution will be related to echo spacing. When the echo spacing is small, $T_2$ distribution at the water-based drilling...
Figure 9. $T_2$ distribution with different antenna lengths when oil-based drilling fluid is used: (a) $L = 24$ inches; (b) $L = 6$ inches.

Figure 10. $T_2$ distribution with different antenna lengths when the dip angle changes, where $d = 2$ mm: (a) $L = 24$ inches; (b) $L = 6$ inches.

fluid filtrate is roughly the same as that at the oil-based drilling fluid filtrate. When the echo spacing is big, the $T_2$ distribution at different drilling fluid filtrates will not be the same.

4. The antenna length will affect the NMR logging response at the fracture reservoir. For a short antenna, NMR logging is more sensitive to fractures.
5. NMR logging may be applied to fracture evaluation if the fracture aperture is big enough. When the fracture aperture is big enough, however, it is still strongly recommended to integrate any other logging information, such as electronic FMI and ultrasonic scanning, into NMR logging. Remember that NMR logging with a gradient magnetic field is a sliced measurement, and it only responds to fracture when the slice measured intersects with the fracture.

References

[1] Yan W L and Fan X M 2009 Response characteristics of dual laterolog for net-fractured igneous reservoir J. Jilin Univ. (Earth Science Edition) (in Chinese) 39 158–62
[2] Liu C B and Li J G 1999 Completely evaluating the tight fracture and/or Vuggy carbonate and igneous reservoir with low porosity Well Logging Technol. (in Chinese) 23 457–65
[3] Xiao L Z 1998 Magnetic Resonance Imaging Logging and Rock’s Magnetic Resonance and its Application (Beijing: Science Press)
[4] Coates G R, Xiao L Z and Prammer M G 1999 NMR Logging Principles and Applications (Houston, TX: Gulf Publishing Company)
[5] Liu T Y, Xiao L Z and Fu R S 2004 Application and characterization of NMR relaxation derived from sphere capillary model (in Chinese) J. Geophys. 47 663–71
[6] Zhu Y Q, Fu Y S and Yang X L 1998 The application of MRIL in exploration of deep layer gas Well Logging Technol. (in Chinese) 22 (Suppl.) 77–80
[7] Wu H Y and Zhu L F 2002 Application of imaging and nuclear magnetic resonance to assessment of fractured reservoir in Cheng Bei (in Chinese) Oil Gas Geol. 23 45–48
[8] Li Z C, Sun J M and Geng S C 2001 Classification of fractured reservoir by $T_2$ spectrum of nuclear magnetic resonance log Geophys. Prospect. Pet. (in Chinese) 40 113–8
[9] Hidajat I and Mohanty K K 2004 Study of vuggy carbonates using NMR and x-ray CT scanning SPE Reservoir Eval. Eng. 7 365–77
[10] Chang C T P, Qiao J L, Chen S H and Watson A T 1996 Investigating the utility of NMR spectroscopic techniques for fracture characterization Trans. SPWLA 37th Annu. Logging Symp. paper QQ
[11] Mengual J F, Recinos L M, Ho E S and Herriandez F G 2000 Formation evaluation in southern Mexico’s low-porosity fractured carbonate rocks using imaging and NMR tools Trans. SPWLA 41st Annu. Logging Symp. paper K
[12] Tan M J and Zhao W J 2006 Description of carbonate reservoirs with NMR log Anal. Method Prog. Geophys. (in Chinese) 21 489–93
[13] Yoshito N and Tsuneo K 2007 Estimation of the apertures of water-saturated fractures by nuclear magnetic resonance well logging Geophys. Prospect. 55 235–54