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Three-dimensional modelling of reservoir fluid typing by applying nuclear magnetic resonance (NMR) and thermophysical parameters

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ABSTRACT Reservoir fluid typing is one of the key parameters in reservoir evaluation and field development planning. Nuclear magnetic resonance (NMR) is one of the most effective and useful methods for fluid identification, based on the petrophysical parameters. NMR determines the kind of hydrocarbon fluids using the parameters obtained from the hydrogen nucleus polarization. A novel algorithm is proposed employing the NMR dependent parameters and thermophysical fluid properties. The NMR intensification index (I_{NMR}) is defined as a function of NMR parameters (i.e. longitudinal relaxation time, transverse relaxation time, and diffusion coefficient). This index can provide effective separation boundaries within the reservoir fluids as the three major classes, including gas, oil and brine phases. The boundaries between the fluid zones are determined by computing the 3D gradient model of I_{NMR} variable against the temperature and viscosity. Using this gradient model, three major fluids with two sharp drops and three transition zones are recognizable. The gaseous phase has the highest value of I_{NMR} while its lowest level is related to the brine-bearing zone. The proposed model can effectively determine the boundaries between different major and transition phases, such as gas, gas-oil, oil, oil-water, water, water-brine and brine zones.

Key words: NMR measurements, reservoir fluid typing, thermophysical parameters, 3D model.

1. Introduction

In the petroleum exploration process, the determination of the hydrocarbon type composition plays a significant role in the reservoir characterization (Myers Jr. *et al.*, 1975; Hsu, 2003). Well logging techniques provide the petrophysical measurements to identify the type, volume and potential of hydrocarbon reservoir (Darling, 2005; Ellis and Singer, 2008). Different analytical methods are being used to provide sufficient information about the characterization of complex fluids. These methods may include gas chromatography, optical and nuclear magnetic resonance (NMR) spectrometry (Liu *et al.*, 2013). NMR tools are a well-known technique to measure the carbon and hydrogen contents of petroleum samples (Durand *et al.*, 2008).

NMR logging is an open hole technique, which can be employed to evaluate the subsurface hydrocarbon reservoirs and directly compute the signal from protons of the formation fluids in

pores. Its applications ascertain the different formation characteristics, including rock porosity, permeability, pore-size distributions, the relative saturations of various fluid types, and bound water estimation (Coates *et al.*, 1999; Xie *et al.*, 2008; Zou *et al.*, 2016). The first step of acquiring borehole NMR logging data is to polarize (align) magnetic nuclear spin in the pore fluid with imposing static magnetic field. These magnetic nuclei are, then, excited by the radio frequency field to define the time period of returning them into balance. The response signal can be considered independent of the matrix material, which is not necessary to calibrate with formation lithology (Dunn *et al.*, 2002).

The reservoir fluids are rich in hydrogen, which can possibly be distinguished against the hydrogen in the pore space based on the relaxation times. The hydrogen NMR signal represents the properties and fractions of fluid as a function of the relaxation times and diffusion rates (Hirasaki *et al.*, 2003; Hürlimann *et al.*, 2009; Edwards, 2011). There are many researches in the literature dealing with interpretation of NMR measurements for hydrocarbon-typing applications. These models have presented the reliable multidimensional relation between NMR measurements (i.e. relaxation times and diffusion) and fluid properties (e.g. specific gravity, viscosity, temperature, and gas-oil ratio) to identify the fluid types of the reservoir (Kleinberg and Vinegar, 1996; Lo *et al.*, 2002; Chen *et al.*, 2004; Sun and Dunn, 2005a; Korb *et al.*, 2015).

In this paper, the reservoir fluids are modelled as three main types: oil, gas, and brine. The different behaviours of the fluids are investigated considering the relationship between the viscosity and temperature. To differentiate the hydrocarbon type contents, an intensifying index is defined employing NMR dependent parameters (relaxation times and diffusion coefficient). A three-dimensional model is proposed, where the NMR intensifying index interpolates into the viscosity and temperature of the fluids to effectively determine the reservoir fluid distributions.

2. NMR dependent parameters for fluid typing

In the NMR characterization, different parameters can be considered, including longitudinal relaxation time (T_1), transverse relaxation time (T_2), diffusion coefficient (D), and hydrogen index (HI). T_1 describes the energy exchange rate between the spin alignment and nuclear environment with surrounding molecules, while T_2 characterizes the decay processes of the nuclear spins to an equilibrium state. D is the rate of movement of different substances across a unit area of a section divided by the space gradient concentration. HI is defined as the relative amount of hydrogen atoms per unit volume of formation. These mentioned parameters are nearly different for each fluid; hence, hydrocarbon typing can be performed using the integration of NMR dependent parameters (Coates *et al.*, 1999; Blümich, 2005; Serra, 2008). Table 1 shows different NMR properties of reservoir fluids.

For fluids in rock pores, there are three mechanisms controlling the relaxation times. The bulk fluid and surface relaxation processes affect both T_1 and T_2 relaxation, while the diffusion in the presence of magnetic field gradients only affects T_2 relaxation. All three processes are independent and act in parallel according to the following equations:

$$\frac{1}{T_1} = \frac{1}{T_{1\text{bulk}}} + \frac{1}{T_{1\text{surface}}} \tag{1}$$

Table 1 - The qualitative descriptions of NMR parameters for different fluid types (Coates *et al.*, 1999).

Parameters \ Fluid types	Light oil	Heavy oil	Brine	Structural water	Gas
T_1	Long	Short	Medium-Long	Very Short	Long
T_2	Long	Short	Medium-Long	Very Short	Short
D	Medium	Slow	Medium	Slow	Very fast

$$\frac{1}{T_2} = \frac{1}{T_{2\text{bulk}}} + \frac{1}{T_{2\text{surface}}} + \frac{1}{T_{2\text{diffusionn}}} \quad . \tag{2}$$

As with bulk relaxation, the diffusion coefficient is controlled by the various physical properties such as viscosity, molecular composition, environmental conditions, temperature, and pressure. Gas, oil, and water diffusion coefficients are given by Eqs. 3 to 5:

$$D_{Gas} \cong 8.5\times10^{-2}\left[\frac{T_K^{0.9}}{\rho_g}\right]\times10^{-5}\frac{Cm^2}{s} \tag{3}$$

$$D_{Water} \cong 1.2\left[\frac{T_K}{298\eta}\right]\times10^{-5}\frac{Cm^2}{s} \tag{4}$$

$$D_{Oil} \cong 1.3\left[\frac{T_K}{298\eta}\right]\times10^{-5}\frac{Cm^2}{s} \tag{5}$$

where T_K = temperature (°K); η = fluid viscosity (cp); and ρ_g = gas density (gm/cm^3).

In the NMR study, one of the most important parameters is the data acquired from the distribution function of the transverse relaxation time. In the relaxation time distribution, the position and spread of the fluid signals depends on fluid viscosity and formation condition. The water-wet formation provides an easier condition for hydrocarbon typing than mixed-wet formations. T_1 contrasts between the hydrocarbon and brine phases, while T_2 contrasts between the gas and oil phases. The contrast between the oil and water phases can be clearly identified by employing diffusion coefficients. T_2 function can also be analysed for determining the range of fluid typing time based on the shapes of distribution functions of T_W (wait time) and T_E (echo spacing). However, 1D and 2D NMR models are the applicable techniques for detecting and quantifying different types of fluids (Sun, 2007).

Hence, the enhanced T_2 relaxation rate in a magnetic field gradient (as the important physical phenomenon) is applied to differentiate oil from water. On the coupling between the magnetic field gradients (G) and T_E, it can characterize the hydrocarbon types and water by comparing the shifts on T_2 spectra at different G-T_E tracks. Another 1DNMR method presents the simultaneous inversion of multiple echo trains to find the T_2 distributions corresponding to various reservoir fluids and formation properties (Prammer *et al.*, 1995; Romero and Zhang, 2010). There are basically two types of 2D NMR post-processing normally used in the industry: D-T_{2int} (diffusivity - T_2 intrinsic) and T_1-T_{2app} (apparent) models.

Comparing with the traditional 1D approach, 2D NMR methods improve the discrimination capability of different fluid contributions by simultaneously plotting proton density (a function of the T_2 relaxation time) at the first variable dimension and diffusion constant (or T_1 relaxation time or T_1/T_{2app} ratio) at the second variable dimension and using forward modelling (Jerath *et al.*, 2012; Meridji *et al.*, 2013).

3. Effective thermophysical parameter in fluid typing

NMR dependent measurements are not perfect to detect fluid types only by themselves. Hence, they can be coupled with the thermophysical properties of fluid systems for effective fluid typing. Temperature and viscosity are the most common variables in the related field of NMR studies (Hirasaki *et al.*, 2003). In the various models, the viscosity is generally predicted as a function of temperature, fluid chemical composition, and some other physicochemical properties. Fluids behave differently in terms of viscosity-temperature relationship. In general, viscosity decreases with increasing temperature, but in the case of gas phase this is reversed (i.e. the viscosity of gases rises as the temperature increases). In the reservoir, the highest viscosity is respectively observed in the brine phase, liquid hydrocarbons, and gases (Zega, 1988; Perry and Green, 1999).

The viscosity of the gases is modelled at different ranges of temperature with increasing trend. However, the gradient of this change is found to decrease with temperature (Fig. 1a). In the study of the thermophysical parameters of liquids such as brine and oil, with rising temperature, the reduction of viscosity is observed in Fig. 1b. As the density of the liquid hydrocarbons augments, the gradient of the viscosity changes with respect to the temperature shows a reducing trend, e.g. from pentane to octane this gradient is increasing (Fig. 1c). It is a common technique to designate the fluid by the viscosity at a certain temperature range and also viscosity-temperature gradient.

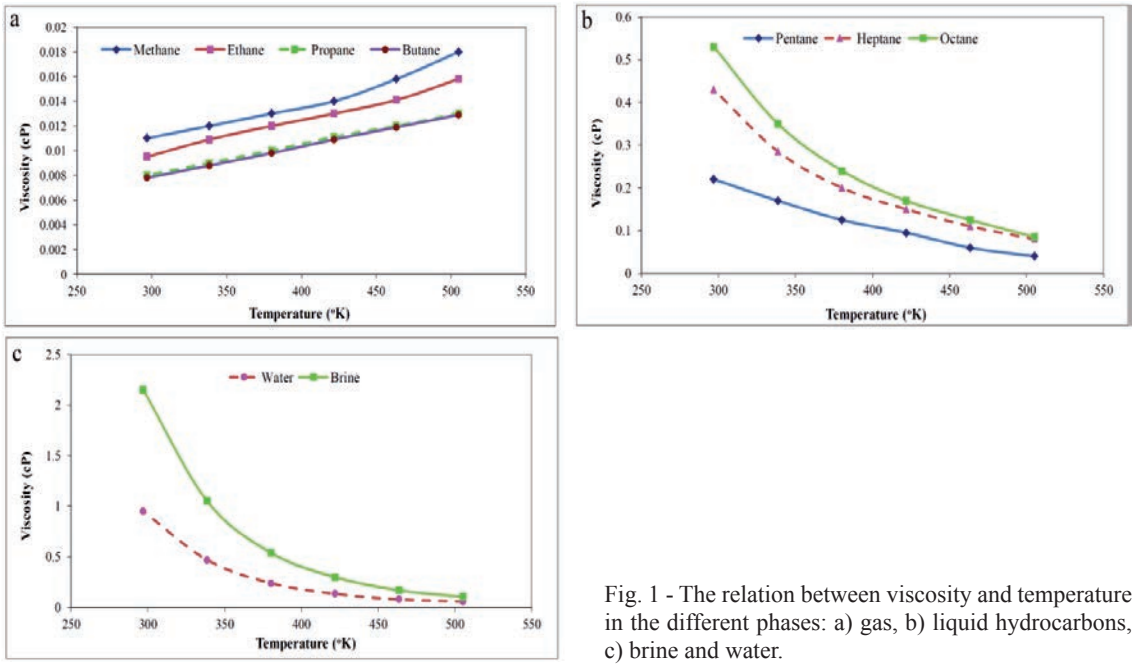

Fig. 1 - The relation between viscosity and temperature in the different phases: a) gas, b) liquid hydrocarbons, c) brine and water.

Reservoir liquid phase has an exceptionally flat temperature-viscosity curve, as the heavy oil slope of the viscosity-temperature dependence is steeper than light oil. The viscosity of gases increases slowly with rising temperature, and shows a nearly linear slope (Loskutov *et al.*, 2014).

4. 3D modelling of the NMR parameters

Sun and Dunn (2005a) proposed a two dimensional model based on the two basic parameters: i) secondary relaxation time and ii) the diffusion coefficient. The third axis expresses the proton population as a function of two other independent variables. These models are shown in the form of the contour map and three-dimensional surface plot. This approach employs the T_2 relaxation rate in a magnetic field gradient and the large contrast between diffusion coefficients of oil and water to model a 2D NMR map, where the oil and water signals are clearly identified. The water-containing zone is detected by its diffusion coefficient being about 3×10^{-5} cm^2/s, whereas the oil peak is found by its location being on a D-T_2 map with linear classifier. The peak points are related to fluids and have a reducing trend from water to oil (Ernst *et al.*, 1987; Sun and Dunn, 2005b; Chen *et al.*, 2016). In Fig. 2, the fluid type determination is modelled based on the changes in T_2 and diffusion rate with respect to the proton population.

Multidimensional NMR analysis significantly improves the accuracy of fluid typing and saturation determination. These methods are particularly efficient to identify highly diffusive fluids (e.g. gas, condensate, and light oil). 3D NMR logging provides multiple formation and the fluid parameters such as porosity, oil and water saturation, oil viscosity, permeability, and wettability (Chen *et al.*, 2016). The 3D NMR model includes diffusion coefficient, T_2, and T_1 relaxation times (D-T_2-T_1) of

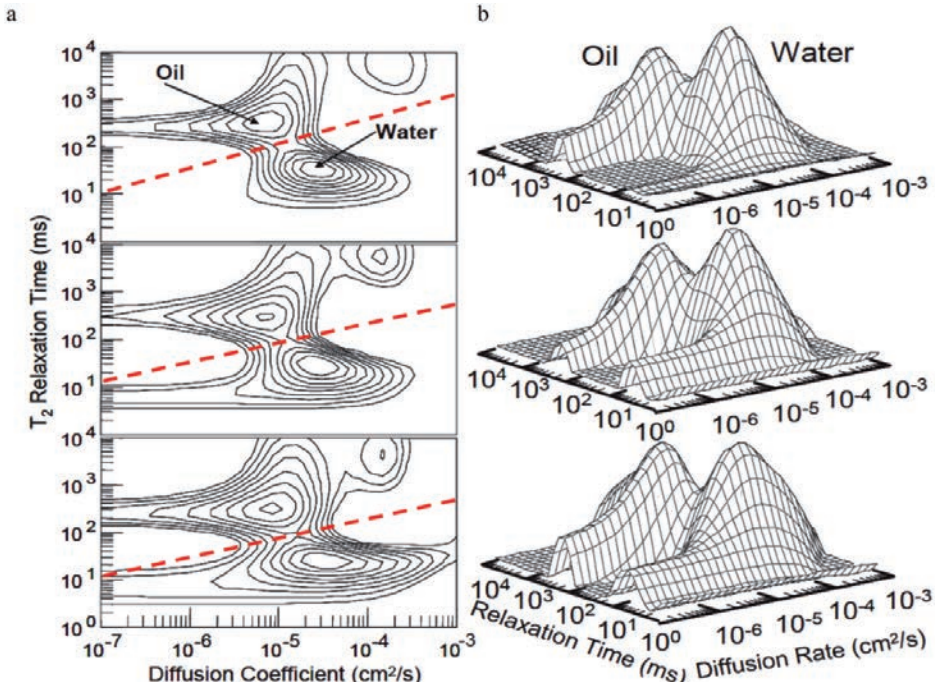

Fig. 2 - The proton amplitude as a function of diffusion coefficient and T_2 relaxation time in the form of: a) the contour map plane, b) three dimensional surface plot (Sun and Dunn, 2005a).

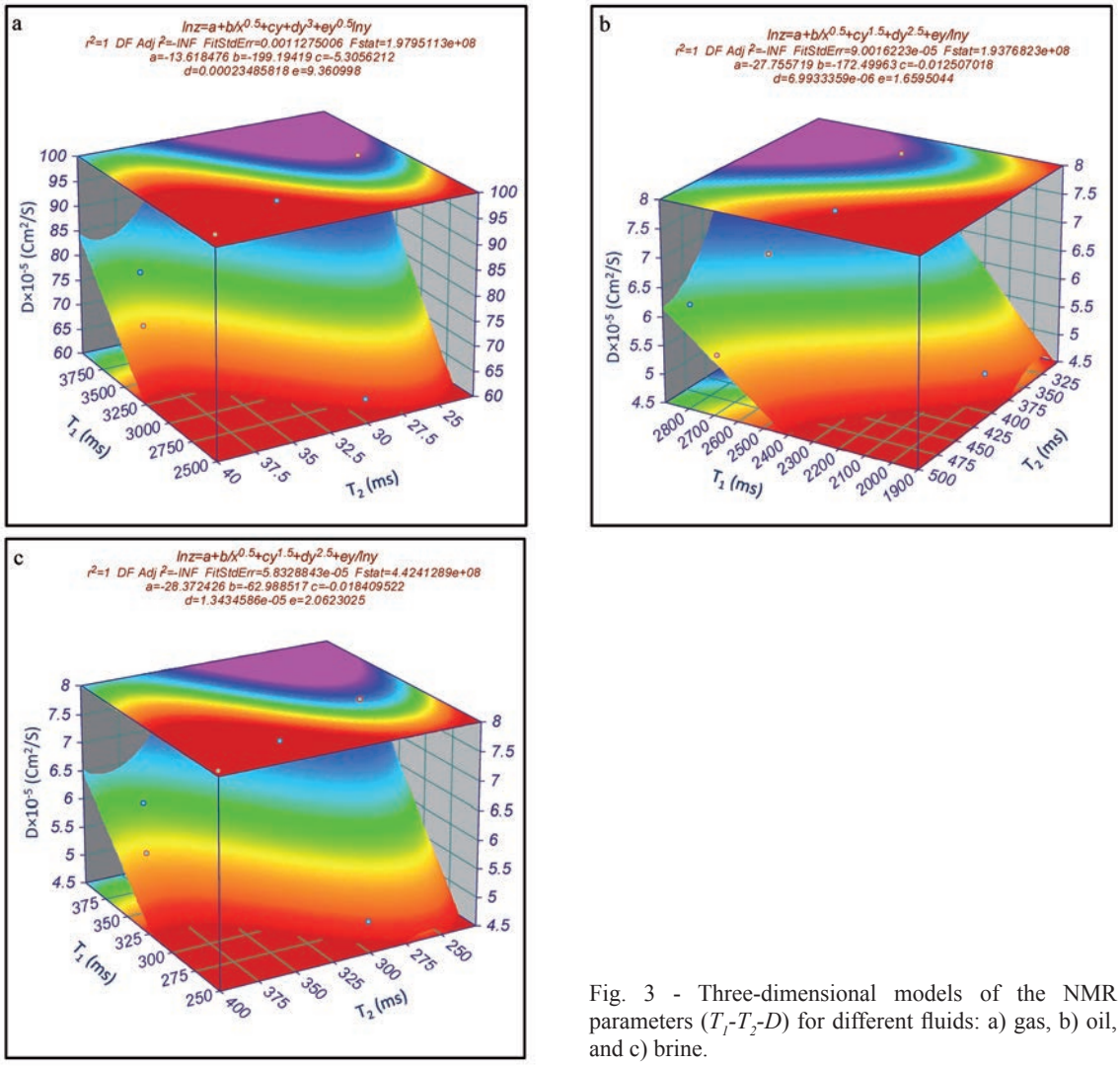

Fig. 3 - Three-dimensional models of the NMR parameters (T_1-T_2-D) for different fluids: a) gas, b) oil, and c) brine.

different fluids in rocks (Fig. 3). These models can actually separate the fluid phases combining the pairwise NMR parameters, but the shape and pattern of models are approximately the same.

To improve the performance of the model, in addition to the NMR parameters (i.e. T_1 and T_2 relaxation times and diffusion coefficient), the thermophysical parameters such as temperature and viscosity are also considered. Initially, the changes of the NMR dependent parameters can be computed for the various types of fluids. In this paper, we introduced the intensification index (I_{NMR}), which can provide effective separation among the fluids within a hydrocarbon reservoir using the following equation:

$$I_{NMR} = D \times \left[\frac{T_1}{T_2}\right] \times 10^8 \tag{6}$$

I_{NMR} index employs different thermophysical and NMR parameters so that it is possible to provide a suitable separation boundary between the different types of fluids within a typical reservoir. For the homogenization of different parameters, the two thermophysical axes from

the quantitative point of view are in the same range. The temperature range of 300 to 500 °K, and the viscosity changes with respect to fluid types in centipoises unit. The third axis, which is perpendicular to the other two, obeys the intensification function as Eq. 3.

After knowing the viscosity variation versus temperature in different reservoir fluids and determining I_{NMR} based on the major NMR parameters, it is now possible to find a proper model for the probable reservoir fluids. In Fig. 4, the model is computed based on the three parameters (i.e. temperature, viscosity, and I_{NMR}). This model presents a surface trend for brine and oil, but for gaseous phase has a more complex trend model considering the relation between the three parameters at different states. These 3D models are separately calculated for gas, oil, and brine and the corresponding evaluated outputs are shown graphically in Fig. 4.

In the vector map (shown in Fig. 5), the gradient arrows show the paths of steepest descent at different points. The direction and length of the arrow depend on the magnitude and the steepness of the slope at each grid node. With the rapid decline along the vertical axis, the breakpoints usually occur at the boundary between the classes through the x-y space in 3D surface. The gradient model of I_{NMR} variable against the temperature and viscosity can be used to determine the effective separation among the fluids within a hydrocarbon. To unify the ranges of x and y axes, the transformation $log(viscosity(cP)^{-100})$ is applied to the viscosity variable.

3D surface is calculated in the form of $z=F(x,y)$ with constant coefficients (w), where x as "$log(viscosity(cP)^{-100})$", y as "*Temperature*", and z as "I_{NMR}". These functions of gas, oil, brine, and hydrocarbon fluids in general are expressed as Eqs. 7 to 10:

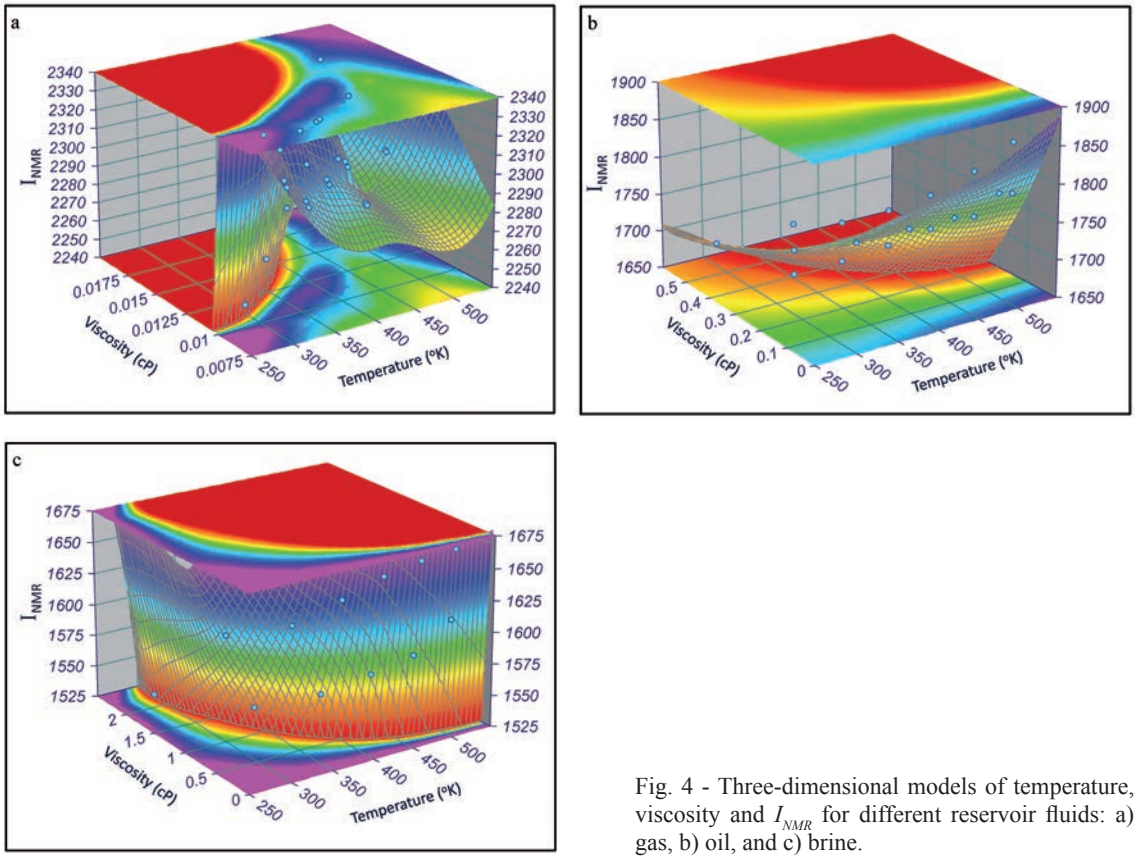

Fig. 4 - Three-dimensional models of temperature, viscosity and I_{NMR} for different reservoir fluids: a) gas, b) oil, and c) brine.

$$z_g = w_0 + w_1 x + w_2 / y + w_3 x^2 + w_4 / y^2 + w_5 x / y + w_6 x^3 + w_7 / y^3 + w_8 x / y^2 + w_9 x^2 / y \quad (7)$$

$$z_o = w_0 + w_1 x + w_2 x^2 + w_3 x^3 + w_4 x^4 + w_5 x^5 + w_6 / y + w_7 / y^2 + w_8 / y^3 + w_9 / y^4 + w_{10} / y^5 \quad (8)$$

$$z_b = w_0 + w_1 x + w_2 x^2 + w_3 x^3 + w_4 x^4 + w_5 x^5 + w_6 y \quad (9)$$

$$z_f = [w_0 + w_1 \ln(x) + w_2 y + w_3 y^2 + w_4 y^3] / \{1 + w_5 \ln(x) + w_6 [\ln(x)]^2 + w_7 y + w_8 y^2\} \quad (10)$$

Fig. 5 shows the general fluid variations in the reservoir under the influence of I_{NMR} and based on the changes of the thermophysical parameters. This illustration uses the vector map representation to distinguish the boundary of the typical fluids within the reservoir and clearly shows the changing border from one phase to another.

Finally, a comprehensive model is proposed to assess NMR dependent I_{NMR} as a function of temperature and viscosity criteria. In this model, the approximate zone of each reservoir fluid is based on the gradient of I_{NMR} parameter. There are three major fluid limitations, including gas, oil, and brine phases. The gaseous phase has the highest value of I_{NMR}, and another sharp drop is observed between the oil and water (brine) phases. However, the boundaries of transition phases are not sharply distinct in the 3D model. The proposed model can provide distinguishable boundaries between different phases, respectively, including the gas, gas-oil, oil, oil-water, water, water-brine and brine. In Fig. 6, the gas-phase has the highest value of I_{NMR} and the lowest level of I_{NMR} is related to the brine-bearing zone.

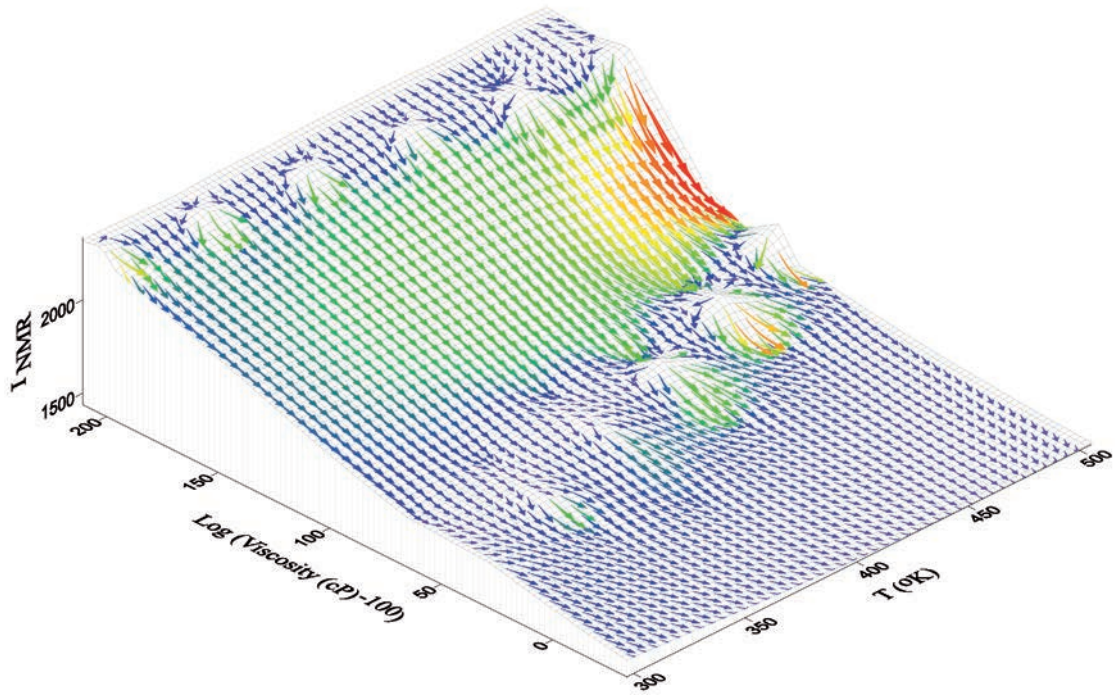

Fig. 5 - Vector map showing the general fluid variations in a reservoir under the influence of I_{NMR}.

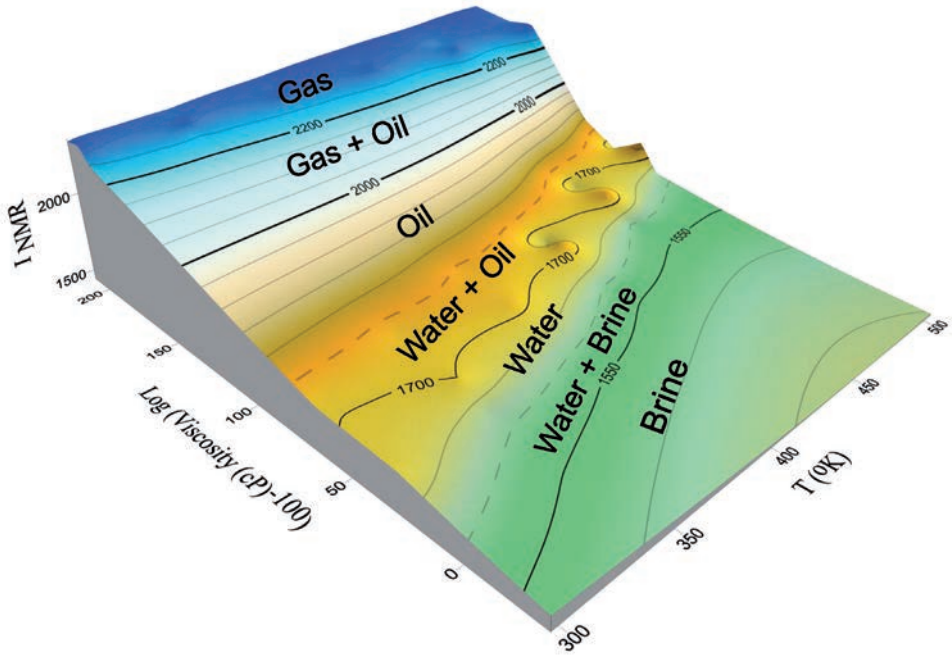

Fig. 6 - Three-dimensional representation of the boundaries between different reservoir fluids based on the thermodynamic characteristics and I_{NMR}.

5. Discussion and practical application

To design an optimal fluid typing, the multiple effective features are selected to achieve the maximum discrimination among the fluid classes. NMR driven parameters incorporate the formation attributes and fluid characteristic. On the other hand, the viscosity of a fluid is highly temperature-dependent measurement to classify and identify the type of fluid. The optimal model of reservoir fluid typing can be considered in terms of trade-off between complexity and performance of input features. The simplest and most efficient model is defined based on I_{NMR} and viscosity/temperature. In the complex and exact model, six dimensional input space is designed, including T_1 and T_2 relaxation times, and diffusion coefficient with the temperature, pressure, and viscosity of the fluids. In this paper, we proposed a model that can balance between the complexity and accuracy using the I_{NMR} and viscosity temperature dependence.

In the form of geological and fluid attributes, the reservoirs can be classified into the homogeneous and heterogeneous types. Geological heterogeneities relate to the spatial variations of facies, porosity, permeability, relative-permeability curves, fracture distributions, etc. Fluid heterogeneities define the spatial distributions of the fluid composition and its properties such as viscosity and density. In reservoir modelling, the distribution of live oil phase viscosity should be considered heterogeneous along the depth. The homogeneous reservoirs with constant viscosity can be considered for highly permeable media. The homogeneous viscosity is equal to the average of the distribution of heterogeneous viscosity versus depth (Chopra *et al.*, 2010).

In the reservoirs, the variations of vertical viscosity show four behaviours: i) the reservoir rapidly fills to an underseal and degradation stops as a result of nutrient transport deficiency to the

oil-water contact (OWC) or charging stops and lighter oil column slowly mixes; ii) the slightly more viscous and degraded hydrocarbon is found at the top of the reservoir, the viscosity-depth profile of the lower zone shows the mixing of oil column after the main charge stops; iii) the profile indicates an extensive degradation continues after the charging stage stops with a lower burnout zone; iv) in the stacked reservoirs, the upper horizon fills first completely and degradation stops, while degradation continues for a longer time in the lower zone (Gates *et al.*, 2008).

Temperature of formation reservoir is assumed to follow the regional or local geothermal gradient. In most cases of petroleum system modelling, the bottom-hole temperature (BHT) is an important parameter to determine the temperature of formation. The changes of temperature around a wellbore are greatly affected by drilling process and fluids. The most reliable sources of formation temperature are provided by drill stem test (DST), modular dynamic test (MDT) and log recorded temperature. Various empirical and theoretical methods of temperature corrections have been presented, which can be applied to the BHT value to model true formation temperature. These corrections are usually performed considering the time since circulation (TSC) recorded with the BHT reading, or the empirical calibration based on the depth of the measurement. In practice, the log recorded temperatures are calibrated to true temperatures derived from DST and MDT considering the depth and TSC (Kutasov and Eppelbaum, 2005; Zare-Reisabadi *et al.*, 2015).

In the hydrocarbon reservoir, the fluid phases are not completely separated, and the boundary between them is very fuzzy as the transition zone. To define this depth interval, the presented model and petrophysical properties are integrated by applying the fuzzy supervised and unsupervised learning algorithms. Each depth section is allocated and shared to different fluid types with the corresponding fuzzy membership degrees. The regions have almost the same membership degree of two fluid types, representing the transition zone (Wong *et al.*, 2002; Hossein Morshedy *et al.*, 2017).

6. Conclusions

Hydrocarbon fluid typing is a crucial step for reservoir characterization, for which NMR logging techniques provide the petrophysical measurements on the properties of fluids, and the sizes of the pores containing these fluids. In this paper, the novel model is proposed to combine the NMR dependent parameters (i.e. longitudinal relaxation time, transverse relaxation time, and diffusion coefficient) with thermophysical fluid properties (i.e. temperature and viscosity). In the study of the thermophysical parameters of brine and oil, the reduction of viscosity is observed with rising temperature, however the viscosity and temperature of gas phase has an inverse relationship. 1D and 2D NMR models cannot perfectly detect and discriminate the different types of fluids existing in the reservoir, hence I_{NMR} is defined as the function of NMR parameters (i.e. T_1, T_2, and D), which can provide effective separation among the hydrocarbon fluid typing. The 3D gradient model of I_{NMR} variable against the temperature and viscosity as logarithmic scale can be applied to determine the boundary between the fluids. In the gradient model, three major fluid zones with two sharp drops are recognizable, including gas, oil, and brine phases. The gaseous phase has the highest value of I_{NMR} and its lowest level is related to the brine-bearing zone. The proposed model can detect distinguishable boundaries between different major and transition phases such as gas, gas-oil, oil, oil-water, water, water-brine and brine zones.

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