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Quantifying fluid distribution and phase connectivity with a simple 3D cubic pore network model constrained by NMR and MICP data

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ABSTRACT

A computer algorithm is implemented to construct 3D cubic pore networks that simultaneously honor nuclear magnetic resonance (NMR) and mercury injection capillary pressure (MICP) measurements on core samples. The algorithm uses discretized pore-body size distributions from NMR and pore-throat size versus incremental pore-volume fraction information from MICP as initial inputs. Both pore-throat radius distribution and body–throat correlation are iteratively refined to match percolation-simulated primary drainage capillary pressure with MICP data. It outputs a pore-throat radius distribution which is not directly measurable with either NMR or MICP. In addition, quasi-static fluid distribution and single-phase connectivity are quantified at each capillary pressure stage. NMR measurements on desaturating core samples are simulated from the quantitative fluid distribution in a gas-displacing-water drainage process and are verified with laboratory measurements. We invoke effective medium theory to quantify the single-phase connectivity in two-phase flow by simulating percolation in equivalent sub-pore-networks that consider the remaining fluid phase as solid cementation. Primary drainage relative permeability curves quantified from fluid distribution and phase connectivity show petrophysical consistency after applying a hydrated-water saturation correction. Core measurements of tight-gas sandstone samples from the Cotton Valley formation, East Texas, are used to verify the new algorithm.

1. Introduction

Understanding fluid distribution at multiple time and length scales in subsurface reservoirs is critical to reservoir characterization, including migration history interpretation, reserves estimation, saturation-height analysis, production optimization, and CO_2 sequestration modeling (Akbar et al., 1994; Parnell and Schwab, 2003; Xu and Torres-Verdín, 2012; Xu et al., 2012a, 2012b; Benson and Cole, 2008). Microscopic fluid distributions determine various saturation-dependent petrophysical properties such as capillary pressure and relative permeability, which directly govern hydrocarbon recovery processes (Lake, 1996; Peters, 2012). Additionally, the fluid distribution has significant effects on various geophysical measurements, including electric or dielectric, acoustic, magnetic resonance, and nuclear well logs (Knight and Nolen-Hoeksema, 1990; Knight, 1991; Endres and Knight, 1991; Garrouch and Sharma, 1995; Chen et al., 1994; Freedman and Heaton, 2004; Xu et al., 2012b). Therefore, it is imperative to study fluid distributions in reservoir rocks by connecting petrophysical principles with the physics of measurements used to probe rocks.

It has been recognized that microscopic fluid distributions in porous media are a consequence of complex physical and chemical processes and depend on many factors such as fluid displacement mechanism, saturation history, flow rate, and wettability (Handy and Datta, 1966; Mohanty, 1981). Many experimental techniques have been advanced to study fluid distributions during multiphase flow. The use of computer tomography and X-ray microtomography to visualize fluid distribution has been reported by several research groups (Peters and Hardham, 1990; Tomutsa et al., 1990; Kumar et al., 2009; Silin et al., 2011; Youssef et al., 2010). NMR imaging is an alternative approach to characterize fluid distribution during two-phase flow (Chen et al., 1994; Liaw et al., 1996; Li, 1997; Chen et al., 2004; Tan et al., 2013). Recently, numerical pore network modeling techniques have become popular in quantifying fluid distributions and predicting petrophysical properties (Mohanty and Salter, 1982; Bryant et al., 1993; Oren et al., 1998; Patzek, 2001; Blunt, 2001; Blunt et al., 2002; Jin et al., 2007; Balhoff et al., 2007; Peng et al., 2009; Sun et al., 2012). Despite their accuracy, most of the above experimental and numerical techniques require significant effort to render a representative pore-network model, which limits their extensive use to assist real-time petrophysical interpretation.

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Nomenclature

a	length of a cube (m)
A	NMR echo decay signal amplitude (mV)
h	cylinder height (m)
k	absolute permeability (mD)
k_{rg}	gas relative permeability (frac)
k_{rw}	water relative permeability (frac)
m	SDR porosity exponential (–)
p	density function of logarithmic pore-throat radius (–)
P_c	capillary pressure(psi)
r	sphere or cylinder radius (m)
R_b	pore-body radius (μm)
R_{th}	pore-throat radius (μm)
S	pore surface area (m^2)
S_{hg}	mercury saturation (frac)
S_{hw}	hydrated water saturation (frac)
S_w	wetting phase or water saturation (frac)
$S_g{}^*$	gas saturation corrected for hydration water (frac)
t	echo decay time (ms)
T_2	NMR transverse relaxation time (ms)
T_{2B}	bulk relation time (ms)
T_{2D}	diffusion relaxation time (ms)
T_{2S}	surface relaxation time (ms)
V	pore volume (m^3)
w_1	Fraction of pore volume connected by large pore-throat size (frac)
w_2	fraction of pore volume connected by small pore-throat size (frac)

Greek letters

θ	contact angle between wetting and non-wetting phase (degree)
$\log \mu_1$	mean value of the large pore-throat radius Gaussian mode (μm)
$\log \mu_2$	mean value of the small pore-throat radius Gaussian mode (μm)
Γ	interfacial tension between wetting and non-wetting phase (dyne/cm)
$\log \sigma_1$	standard deviation of the large pore-throat radius Gaussian mode (μm)
$\log \sigma_2$	standard deviation of the small pore-throat radius Gaussian mode (μm)
ϕ	total porosity (frac)
ρ	surface relaxivity (μm/s)

Acronyms

3D	three-dimensional
CPU	central processing unit
MICP	mercury injection capillary pressure
NMR	nuclear magnetic resonance
RBLM	log-mean pore-body size
SDR	Schlumberger Doll research
T2LM	log-mean transverse relaxation time
XRD	X-ray diffraction

In this paper, we introduce an efficient computer algorithm to construct random 3D cubic pore network models constrained by NMR and MICP measurements acquired from core samples. In addition to pore-throat radius distributions, the algorithm outputs quantitative quasi-static distributions of a specific fluid phase. NMR measurements simulated for desaturating core samples are verified with laboratory measurements. Archie's concept of "effective pore size distribution" is invoked to quantify single-phase connectivity by simulating percolation in equivalent sub-networks that consider the remaining fluid phase as solid cementation. This method generates primary drainage relative permeability curves comparable to NMR-derived values on a first-order approximation. Core measurements acquired from tight-gas sandstone samples from the Cotton Valley formation, East Texas, are used in the study to verify the new algorithm.

2. Pore system characterization with MICP and NMR

NMR and mercury porosimetry are two experimental techniques commonly used to characterize pore systems (Coates et al., 1999; Purcell, 1949; Peters, 2012). Different pore-size information from NMR and MICP data were analyzed and compared in detail by Basan et al. (1997). Methods of correlating MICP and NMR data were documented elsewhere (Altunbay et al., 2001; Marschall et al., 1995; Gao et al., 2011). Projects about combining MICP and NMR data to predict permeability have also been documented in the open technical literature (Glover et al., 2006). However, it should be noticed that MICP and NMR measurements are essentially different in their physics, whereby they probe pore systems based on different petrophysical principles.

NMR transverse relaxation time (T_2) is mainly sensitive to pore-body size. With the assumption that bulk relaxation and diffusion coupling are negligible in a fully water-saturated rock sample measured under a constant magnetic field, T_2 is related to pore-body size by (Coates et al., 1999)

$$\frac{1}{T_2} = \rho \frac{S}{V}, \tag{1}$$

where ρ is surface relaxivity in μm/s, S/V is surface to volume ratio in μm^{-1} which quantifies the pore-body dimension. Table 1 lists the surface to volume ratio of some simple pore-body geometries. In this paper, spherical pore geometry is assumed to simulate NMR and mercury injection measurements. The use of alternative pore geometries requires additional testing.

For a spherical pore body of radius R_b, T_2 is expressed as

$$T_2 = \frac{R_b}{3\rho}. \tag{2}$$

Fig. 1 shows an example of converting the NMR T_2 spectrum to a pore-body size distribution assuming spherical pore geometry via Eq. (2) for a tight-gas sandstone sample. The same sample will be subsequently used for testing the pore-network inversion algorithm.

Mercury porosimetry (Webb, 2001) quantifies the pore volume accessible to the invading non-wetting phase at an exerted value of capillary pressure (P_c), which relates to pore-throat size through

Table 1
Surface to volume ratio of simple pore-body geometries.

Pore geometry	*Surface*	*Volume*	*Surface/ volume*
Sphere (radius$=r$)	$4\pi r^2$	$4\pi r^3/3$	$3/r$
Cube (length$=a$)	$6a^2$	a^3	$6/a$
Open-ended cylinder (radius$=r$; height$=h$)	$2\pi rh$	$\pi r^2 h$	$2/r$