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Natural and induced fractures in coal cores imaged through X-ray computed microtomography — Impact on desorption time

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ABSTRACT

Fractures are important in tight formations because they can constitute major paths for fluid flow and increase drainage surface area in oil and gas systems. The natural heterogeneity of subsurface formations is largely simplified or homogenized in practical applications. However, detailed rock characterization of natural discontinuities and planes of weakness can play a decisive role in judging fracture-matrix interaction and the effective properties of tight reservoir formations. We show the results of X-ray microtomography on coal cores with natural and induced fractures accompanied by digital image analyses for fracture discretization and numerical simulation of compressible fluid flow from an adsorptive medium to discrete fractures. Reconstructed tomographic images provide evidence of a complex network of open and mineralized fractures that interacts with induced shear fractures. Mineralized veins occupy from zero to up to 6% volume fraction in some bedding layers. Open fracture porosity is generally lower than 1% except upon shear and dilation. Natural fracture patterns can drastically change in less than 1 cm in direction perpendicular to bedding indicating strong lamination. X-ray microscopy can help assess brittleness during failure, the role of preexistent fracture tips on induced fractures, and potential for fines production. Digital image analysis based on the Hough transform yields meaningful results locating and characterizing a large number of fractures automatically along the core. Numerical simulation results show that desorption times can be more than two orders of magnitude faster in fractured coal than in the intact coal matrix. The use of tracers helps observe and model fluid flow and uptake in fracture-matrix systems. Altogether, combined X-ray tomography, image processing, and numerical simulation help visualize and quantify the complexity and heterogeneity of naturally fractured geological samples in views of applications to integrated reservoir petrophysical and geomechanical characterization.

1. Introduction

Subsurface formations are characterized by varying levels of heterogeneity at various length scales, including changes in lithology, faults, joints, and natural fractures in general. Mechanical discontinuities in subsurface formations are a result of various processes including tectonic loading, burial/uplift, folding, thermal cooling, chemical diagenesis, change in pore pressure, and phase intrusion among others (Pollard and Fletcher, 2005; Fossen, 2010). Associated changes of stresses can result in fractures in opening or shearing mode. Fractures constitute localized features that may significantly affect fluid flow in subsurface formations (Hennings et al., 2000; Fisher and Knipe, 2001). Fluid flow through a fracture depends on both normal effective stress and deviatoric stress (Barton et al., 1995).

From an engineering point of view, natural fractures are important because they can facilitate depletion in tight reservoirs (Curtis, 2002), impact hydraulic fracture branching (Olson, 2008; Gale and Holder, 2010; Lee et al., 2015), and also serve as pathways for leakage of injected fluids into overlying and underlying formations.

Conductive fractures help reduce the path length of hydrocarbons from their original site, through low permeability rock matrix, to the nearest set of conductive fractures to the wellbore. Fluid transport through low permeability rock matrix can be simplified as compressible fluid flow in a tight medium. The transport equation takes the form of the diffusion equation (for pore pressure) with a characteristic diffusivity parameter that is a function of the porosity and permeability of the porous medium and the viscosity and compressibility of the fluid (Patzek et al., 2013). The associated characteristic time to achieve steady-state conditions is proportional to the square of the characteristic drainage length. In other words, the distance between conductive natural fractures readily affects the time needed to achieve steady-state fluid flow rates and the characteristic depletion time.

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Coal seams are naturally fractured formations. Diagenetic processes lead to opening mode fractures predominantly oriented perpendicular to the bedding plane, called cleats (Laubach et al., 1998). Fracturing density varies with coal type and depends on subcritical fracture propagation characteristics (Tremain et al., 1991; Olson, 1993). Cleats account for most of the permeability at the seam scale (Mazumder et al., 2006; Pan and Connell, 2007). Hydro-geochemical events can lead to precipitation of epigenitic or diagenetic minerals such as calcite and pyrite in the fracture openings (Pitman et al., 2003). At the smallest scale, coal seams are constituted by a microporous disordered organic continuum usually termed as coal matrix. Micropores (and mesopores) sized in the order of 10^{-9} m to 10^{-8} m compose most of the coal matrix porosity. Transport processes induced by coal seam depressurization are quite complex and involve gas diffusion, slip flow, Darcy flow, and likely turbulent flow in large fractures (Ceglarska-Stefanska and Zarebska, 2002; Shi and Durucan, 2003). Usually double-porosity and triple-porosity models are needed to capture various transport processes from the coal matrix to the well (Chalmers et al., 2012; Wei and Zhang, 2010). Coal core scale permeability ranges from a few μD to mD depending on the degree of fracturing, effective stress, and gas pressure (Gensterblum et al., 2014). Recent advances on gas shales show that even extremely tight rocks can be subjected to a pressure gradient and measure Darcy-equivalent permeability in the order of a few nD to μD (Javadpour et al., 2007; Cui et al., 2009; Chalmers et al., 2012; Tinni et al., 2012). In the case of microporous coal and organic shale, sorption must be taken into account as an additional source and drive for hydrocarbon recovery (Cui et al., 2009; Pan and Connell, 2007). Well known sorption-induced swelling properties of coal can drastically affect fracture permeability and must be taken into account to predict reservoir performance (Palmer and Mansoori, 1998).

Natural fractures have primary importance in defining effective transport properties in tight formations at the reservoir scale. However, typical field geophysical methods and wellbore logging tools cannot detect small natural fractures. Thus, routine formation evaluation usually underestimates rock heterogeneity. Core fracture visual inspection is usually qualitative. X-ray computed tomography (CT) is a non-destructive laboratory tool that permits imaging heterogeneity of geological materials (among others) in three dimensions (Ketcham and Carlson, 2001; Cnudde and Boone, 2013). X-ray tomography and microtomography has become widely used by oil and gas service companies that require a detailed characterization of subsurface formations (Amendt et al., 2013). A limited number of manuscripts addresses natural fracture mapping in coal seams. There is an inherent trade-off in imaging coal because fracture size distribution is fractal (scale-dependent). CT scanning of large coal blocks (L > 10 cm) permits capturing large scale discontinuities (primary cleats) likely responsible for large scale seam permeability – resolution ~500 μm (Karacan and Okandan, 2000; Bossie-Codreanu et al., 2004; Mazumder et al., 2006). CT scanning of small cores (L ~ 1 cm) permits mapping smaller fractures (secondary to tertiary cleats) which likely play a lesser role in seam scale permeability but contribute to fluid drainage through fracture-matrix interaction. Higher resolution imaging techniques, such as, light microscope and SEM have been use to complement CT methods (Karacan and Okandan, 2000; Espinoza et al., 2014). High resolution X-ray microtomography can be used to measure topology of selected fractures (Johns et al., 1993; Ketcham et al., 2010). Recent work evaluated the role of deviatoric and pore pressure loading on induced fractures in coal through X-ray microtomography (Kumar et al., 2011; Cai et al., 2014). Both studies indicate a link between pre-existent natural fractures and induced fractures. Tracers, such as xenon, can also be used with X-ray tomography to identify small fractures and map adsorption (Karacan and Okandan, 2001; Mayo et al., 2015). The literature, so far, has based fracture characterization on finger-picked planar shapes recognized after segmentation. Such methodology is subjective and can take significant time.

The objective of this study is to image and locate secondary/tertiary cleats in coal samples through X-ray microtomography, 3D imaging, and digital image processing, in order to understand and capture the complexity of naturally fractured coal. Emphasis is put on fractures at the 10^{-2} m-scale that connect to the coal matrix and define coal matrix-fracture interaction rather than on the effective seam permeability. Image analysis is used as a tool for measuring volume fractions and characterizing fracture location and orientation along the core with potential application to analysis of 4 in-field cores. Numerical simulation permits estimation of the impact of natural fractures on the desorption times of fractured coal cores and on depletion of reservoirs with a tight adsorptive rock matrix.

2. Material and methods

2.1. Coal specimens

The tested coal comes from Forzando mine, a mining facility on the Highveld coalfield in South Africa part of the Permian Ecca Group. The recovered coal block shows a high degree of natural fracturing with a fair percentage of mineralized calcite-filled cleats (Fig. 1). Bedding heterogeneity is visible in several sections. Measured ash and volatile-matter yield on crushed coal from the same seam are 16.5% and 46.6% respectively. The tested coal classifies as sub-bituminous A/high volatile C bituminous considering its vitrinite reflectance ~0.57% (ASTM D 388). We drilled 38 mm diameter cores oriented perpendicular to the bedding plane (Fig. 1). The imaged specimens showed negligible damage during coring. Mechanical measurements at the core scale (38 mm diameter) indicate: Young's modulus of ~2.7 GPa (with significant elastic non-linearity), Poisson's ratio of 0.27, unconfined compression strength of 22 MPa, and friction angle of ~50° (Espinoza et al., 2014). Permeability perpendicular to bedding at the core scale (38 mm diameter) varies from 0.02 mD to 0.0001 mD as effective isotropic stress increases from 1 to 25 MPa (Espinoza et al., 2014). The Langmuir sorption (total uptake) parameters of the coal matrix at 40° are $P_L = 1.6$ MPa and $V_L = 0.046$ m^3/kg (volume at atmospheric pressure). One of the imaged coal cores was failed in shear under a specific pressure-stress loading path meant to simulate depletion at in-situ conditions, i.e., desorption from 10 MPa to 1 MPa fluid pressure (CO_2) under uniaxial strain condition with ensuing deviatoric stress increase from 15 MPa to ~28 MPa – further details in (Espinoza et al., 2015).

2.2. X-ray microtomography

X-ray microtomography was performed at Laboratoire Navier with an Ultratom RXSolutions scanner (http://navier.enpc.fr/Microtomographe). The X-ray source was set to 100 kV and 250 μA, and the detector frame rate to 5 and 7 fps with an average of 10 images (i.e., total exposure time of 1.4 and 2 s). The tomograph took 1440 radiographies over 360°. A copper filter of 0.1 mm thickness was used to reduce beam hardening effects. We used filtered back projection (Feldkamp method-cone beam geometry with Tukey filter) to reconstruct tomographic images. Because of the specimen slenderness, the scan was performed in three sections with necessary overlap to get a full 3D continuous scan. The result is a 16-bit image of 2024 × 2024 × 7200 voxels. ImageJ and VolumeViewer enabled 3D visualization and animation of the complete stack of slices.

2.3. Desorption and image analysis

The desorption analysis mimics experimental conditions for a coal core in a Hassler core-holder in which end caps act as drains and an impermeable membrane surrounds the core. The synthetic model for desorption analysis considers that the core can be analyzed as a stack of "discs" that have fractures well connected to low pressure drains