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Characterization of multi-fractured horizontal shale wells using drill cuttings: 2. Permeability/diffusivity estimation

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ABSTRACT

There is considerable research interest in the transport properties of shales to assist in their evaluation as reservoirs for natural gas and oil. However, shales have proven difficult to characterize, in part because of the challenges of obtaining viable reservoir samples from multi-fractured horizontal wells used to produce from them. Often the only reservoir samples available from horizontal wells are drill cuttings – the sample sizes obtained from cuttings are typically too small for quantitative analysis using conventional techniques. Therefore, new, high-precision methods are required to analyze the smaller cuttings samples. Further, the physics of gas storage and transport through the multi-model pore structure of shale is complex, requiring rigorous modeling approaches to extract parameters of interest such as permeability/diffusivity.

In this work, the use of a high-precision, low-pressure adsorption device is explored for extracting permeability/diffusivity parameters from small amounts (1–2 g) of artificial (crushed core sample) drill cuttings of Duvernay shale. In order to extract the transport parameters, gas flow through the complex, heterogeneous matrix pore structure of the shale has been approximated using a general dual porosity numerical model which assumes that (1) gas flows through macropores by continuum viscous flow (2) gas flows through meso and micropores by Knudsen diffusion and molecular slippage on pore walls and (3) adsorption occurs in meso and micropores. The model can be simplified into two sub-models, a macro/micropore system or meso/micropore system, depending on the measured pore size distribution of the samples of interest.

The new multi-pore (bidisperse) numerical model is applied to carbon dioxide low-pressure adsorption rate data obtained from the crushed Duvernay shale core samples, and apparent permeability for each gas/sample group is calculated at different pressure steps. The low-pressure adsorption device yields pressure-time data that is of much better quality than a commercial crushed rock permeability device that requires larger sample sizes. The new bidisperse pore structure numerical model, which allows permeability to vary (at each pressure step) due to gas slippage effects, properly describes the entire adsorption rate history of the samples studied. Mesopore apparent permeabilities range from1 $\times$ 10^{-2}–1 $\times$ 10^{-3} mD and micropore apparent diffusivities are in the 1 $\times$ 10^{-7} mD range. The calculated apparent diffusivities obtained from modeling adsorption rate data change with pressure.

The results of this study have important implications for shale matrix transport characterization. The resulting data can be used for making completions decisions and in reservoir models which capture reservoir property changes along a horizontal lateral.

1. Introduction

Although static volumetric calculations often indicate large in-place hydrocarbon volumes for shale (adsorbed plus free gas), it is the rate of desorption (in organic-rich shales) and diffusion/flow that dictate the timescales needed to produce hydrocarbon gas through primary production, or inject CO_2 for enhanced recovery of hydrocarbons and storage in shale. Therefore, a good understanding of the transport properties of the shale matrix and fracture system is required for accurate production predictions. Matrix permeability, which is the subject of the current study, is a

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particularly important control on long term fluid flow in unconventional reservoirs.

However, shale matrix permeability is challenging to measure in the laboratory. The various techniques used for this purpose operate on different physical principals and utilize samples of different sizes and geometries, subjected to contrasting measurement conditions (Ghanizadeh et al., 2015a). Crushed rock permeability measurements are often performed to obtain a "true" measurement of matrix permeability (Handwerger et al., 2011). Although commercial labs routinely perform these analyses, the procedures and algorithms used for analysis are not always disclosed. Further, commercial equipment often gives one value (average) for permeability. The experimental and modeling attempts for describing diffusion/flow mechanism of coal reservoirs have a long history; however, these techniques are still being evolved for shales. In the following, a brief summary of attempts to extract coal diffusivity values is provided, followed by a summary of methods for shale matrix permeability calculation.

1.1. Diffusivity/permeability studies performed for coal

Some researchers suggest that a single coefficient is sufficient for describing matrix transport through coal (Charrière et al., 2010; Ciembroniewicz and Marecka, 1993; Jian et al., 2012; Pone et al., 2009; Švábová et al., 2012), while others apply a more general two coefficient model (Busch et al., 2004; Clarkson and Bustin, 1999; Cui et al., 2004; Shi and Durucan, 2003; Siemons et al., 2007) to describe diffusion in samples with a relatively wide pore size distribution. Proponents of the "bidisperse" pore structure approach suggest that one single average value for pore size may no longer represent the whole sample.

In order to determine the desorption/diffusion behaviour of coal, experiments can be designed to directly measure sorption kinetics (Charrière et al., 2010; Gruszkiewicz et al., 2009; Shi and Durucan, 2003).

A subject of debate in the experimental estimation of coal diffusion coefficients is whether diffusion coefficients increase or decrease with an increase in pressure. The dominant trend in diffusivity/permeability with pressure has implications for modeling both primary and enhanced recovery/CO_2 storage in unconventional reservoirs. Even with similar models, some authors have found that diffusion coefficients increase with increasing pressure (Charrière et al., 2010; Ciembroniewicz and Marecka, 1993; Jian et al., 2012), while others have found that they decrease (Busch et al., 2004; Cui et al., 2004; Pone et al., 2009; Shi and Durucan, 2003; Siemons et al., 2007). Still others have found that different models may give different pressure trends depending on the model chosen, even when using the same data (Clarkson and Bustin, 1999; Staib et al., 2013). Staib et al. (2013). recently summarized that the lack of consistency in the deduced effects of pressure could be due to: (i) choice of model, (ii) choice of experimental conditions, and (iii) choice of coal sample.

1.2. Diffusivity/permeability studies performed for shale

Matrix transport mechanisms of shale are likely quite different from coal, in part due to the difference in pore structure of the matrix, and also different pore associations within organic and inorganic matter, the latter of which is typically not as important for coal. There appear to be very few studies performed that account for specific transport physics while estimating the permeability of shale samples. Recently, Heller et al. (2014) used helium at relatively high pressure (~1 MPa) as the test gas and measured permeability of some crushed shale samples. Helium was used to avoid the effects of adsorption and/or associated swelling that might impact permeability. Those authors then applied the model suggested by Cui et al. (2009), while neglecting the Klinkenberg slippage effect, to analyze pressure vs. time data of crushed shale samples. Because of low accuracy of the experimental data, Heller et al. (2014) were only able to fit their data with lower and upper bound curves, as opposed to a single curve. For shales, particularly when adsorptive gases are used for measurement, it is important to properly capture the potentially significant effects of adsorption, slippage and diffusion.

Researchers such as Ertekin et al. (1986), Javadpour (2009), and Civan (2010) have evaluated permeability coefficients in the shale matrix and concluded that, while gas flows through nano-scale pores at low pressures, the mean-free path of gas molecules is comparable to the average effective rock pore throat radius causing the gas molecules to "slip" along pore surfaces (as noted by Klinkenberg, 1941) – this slip-flow creates an additional flux mechanism which may be additive to viscous flow and diffusion flow, causing a higher apparent permeability. In the Javadpour model (Javadpour, 2009), pressure-driven flow of shale nano-pores was modeled using Darcy's Law corrected for slippage, while concentration-driven flow was modeled with Fick's Law.

These complexities in matrix transport property determination for shale make it difficult for reservoir engineers to obtain representative values for use in shale reservoir simulation. Further, use of reservoir simulation to study the effects of fluid storage and transport mechanisms on primary and enhanced shale gas recovery requires a relatively large dataset. Although some of these data are available for well-developed shale reservoirs, they are limited for other unconventional reservoirs such as the liquid-rich portions of the Duvernay and Montney formations in Western Canada, which have recently received a great deal of attention and are in early stages of development (Ghanizadeh et al., 2015a,b,c).

Rock samples of these reservoirs are required as a source of reservoir property information; however, typically the only source of rock samples from horizontal wells used to develop these unconventional reservoirs are rock (drill) cuttings. Because rock properties and reservoir quality are expected to vary significantly along the length of a horizontal well (Clarkson and Haghshenas, 2016), it is critical to assess these properties quantitatively from cuttings. However, quantitative analysis procedures for drill cuttings are in their infancy (Ortega and Aguilera, 2013, 2014). The conventional methods proposed in the literature for shale sample permeability evaluation require a large quantity of sample (i.e. cores or core plugs) that are not typically available for horizontal laterals, but rather from offset (and rare) vertical wells. Matrix permeability is then typically measured using 30 g (or more) of crushed rock samples obtained from cores extracted from the vertical wells.

In this Part 2 of a two-part series on drill cuttings analysis (Part 1 by Clarkson and Haghshenas, 2016; addresses fluid-in-place calculations) experimental procedures and modeling techniques are developed to allow the extraction of permeability/diffusivity from drill cuttings collected at multiple intervals along a horizontal well, which in turn enables the evaluation of reservoir heterogeneity. Drill cuttings obtained from horizontal wells present challenges for characterization due to small sample sizes (typically $< 2–3$ g). Therefore, in the current paper, laboratory and modeling procedures for extracting critical reservoir properties (e.g. permeability or diffusivity) from small sizes of crushed samples are developed. "Artificial" cuttings derived from previously-analyzed core plug samples (Ghanizadeh et al., 2015a) are used to develop the procedures and allow for comparison of the results with larger-scale samples. The experimental procedures used historically for analyzing coal (Busch et al., 2004; Ciembroniewicz and Marecka, 1993; Clarkson and Bustin, 1999; Cui et al., 2004; Jian et al., 2012;