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Porosity characteristics of the Devonian Horn River shale, Canada: Insights from lithofacies classification and shale composition

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ABSTRACT

This study evaluates pore systems of the Horn River shale in Western Canada Sedimentary Basin from lithofacies classification of core samples to micro-scale pore structure investigation. Samples from the Middle and Upper Devonian Horn River shale sequence were examined by core description, porosity measurement, SEM, and TEM imaging of ion milled samples, and nitrogen adsorption analysis in order to develop a better understanding of the controls of organic and inorganic rock constituents on porosity development and pore microstructure.

Five primary shale lithofacies were identified by hand-core and thin section analyses: massive mudstones, massive mudstones with pyrite streaks, laminated mudstones, bioturbated mudstones and carbonates. Porosity ranges from 0.62% to 12.04% and shows wide variation between different lithofacies. Massive mudstones and pyritic mudstones with high total organic carbon (TOC) content have the highest porosity, whereas bioturbated mudstones and carbonates with low TOC content have the lowest porosity. SEM and TEM images suggest that several kinds of sites for porosity development are present, including organic matter, pyrite framboids, clay platelets, quartz rims, carbonate grains and microfractures. A general positive relationship between TOC and porosity indicates that a large proportion of pores are developed in organic matter. Results from the nitrogen adsorption analysis suggest that samples with more organic matter tend to develop smaller pores. Thus while porosity development is a combined function of organic matter, mineral components, fabric and fractures, it is most affected by organic matter concentration.

The Muskwa Formation and the Evie Member have more gas storage capacity as they primarily consist of massive mudstones and pyrite-rich mudstones, showing the best porosity. The Otter Park Member has lower porosity, which may relate to the fact that its lithofacies mainly consists of laminated mudstones and bioturbated mudstones.

1. Introduction

Shales or mudstones are fine-grained sedimentary rocks with a dominant grain size less than 63 μm (Schieber, 1998). Due to recent advances in horizontal drilling and hydraulic fracturing techniques, oil and gas are now economically produced from shale reservoirs (Curtis, 2002; Hao et al., 2013; Jarvie et al., 2007) that were previously considered only as source rock and seals for conventional oil and gas reservoirs. Shale reservoirs are typically characterized by low porosities ranging from 3.1 to 11.7%, and unlike conventional reservoirs, which usually have micron scale pores (Curtis et al., 2012; Nelson, 2009), pore sizes in the nanometer range (Curtis et al., 2010, 2012; Louks et al., 2009) and extremely low permeabilities ranging from 2.4×10^{-1} nanodarcies to 1.6×10^{2} nanodarcies (Yang and Aplin, 2007). Natural gas is stored in three forms: free gas in pores and fractures, gas adsorbed to the surface of organic matter and inorganic composition, and dissolved gas in water, oil and bitumen (Curtis, 2002). Porosity and pore structure are the most significant factors controlling gas storage capacity and deliverability. Understanding factors controlling shale storage capacity and investigating the pore structure are of great significance for successful evaluation and exploitation of shale oil and gas reservoirs.

Two fundamentally different approaches have been applied to elucidate the complex pore systems of shales. Direct imaging methods, including scanning electron microscopy (SEM) and transmission electron microscopy (TEM) imaging methods, combined with focused ion milling techniques, provide information on pore size, pore morphology, sites for pore development and connectivity between pore networks. Indirect methods, such as helium porosimetry, mercury injection capillary pressure, nuclear magnetic resonance spectroscopy and nitrogen adsorption, provide an estimation of bulk properties of a sample, including porosity, pore size and morphology (Curtis et al., 2011, 2012; Dong and Harris, 2013; Milner et al., 2010; Sondergeld et al., 2010; Wang and Reed, 2009).

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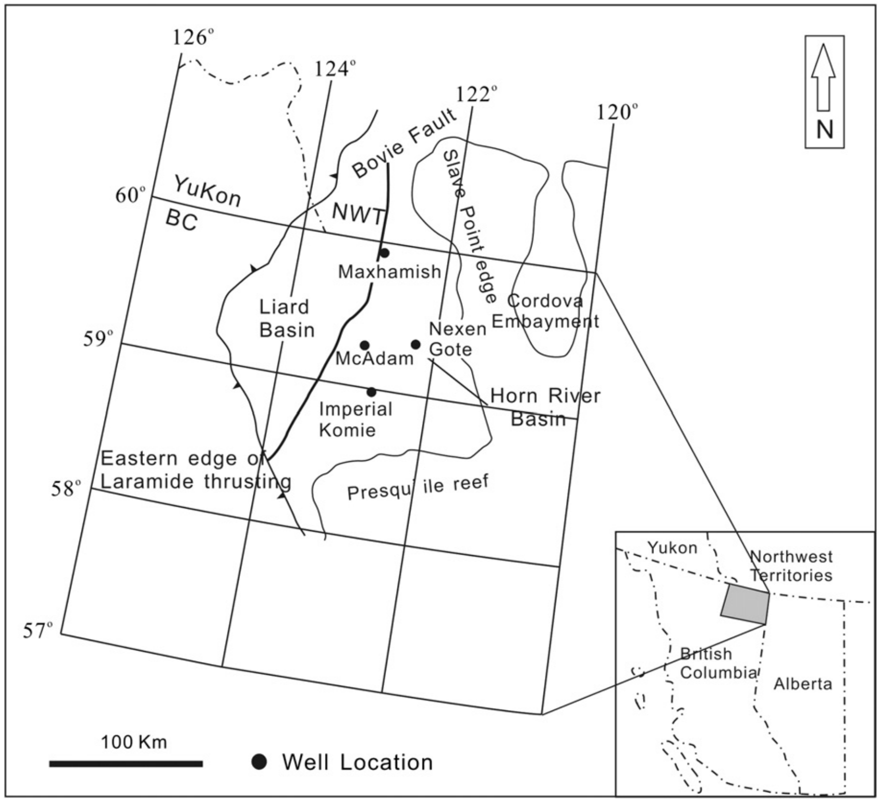

Fig. 1. Map of Horn River Basin and adjacent areas (Liard Basin and Cordova Embayment), showing well locations (modified after Ross and Bustin, 2008).

Early investigations of pore systems in shale samples from Mississippian Barnett Shale that applied scanning electron microscopy to Ar-ion-beam milled samples showed that pore size is dominantly nanometer in scale (Louks et al., 2009). Several modes of porosity development have been identified in both Barnett and Woodford Shales: associated with organic matter, floccules, porous fecal pellets, preserved fossil fragments and various minerals such as pyrite framboids, microchannels, and microfractures (Schieber, 2010; Slatt and O'Brien, 2011). Although a variety of pore shapes and origins have been described in mudrocks (Louks et al., 2009; Passey et al., 2010), three primary classes of pores within shales are proposed: interparticle mineral pores, intraparticle mineral pores and intra-organic matter pores (Loucks et al., 2012). Porosity in shale successions is thought to be a direct outcome of depositional and diagenetic processes (Jennings and Antia, 2013; Schieber, 2010), depending on organic matter concentration, mineralogy, fabric, texture and microfractures (Loucks et al., 2012). Depositional environments significantly control shale fabric and mineralogical composition such as lamination, organic matter concentration, clay, quartz, and carbonate content, while diagenetic processes alter that fabric and composition. Although the geochemical controls on shale microstructure have

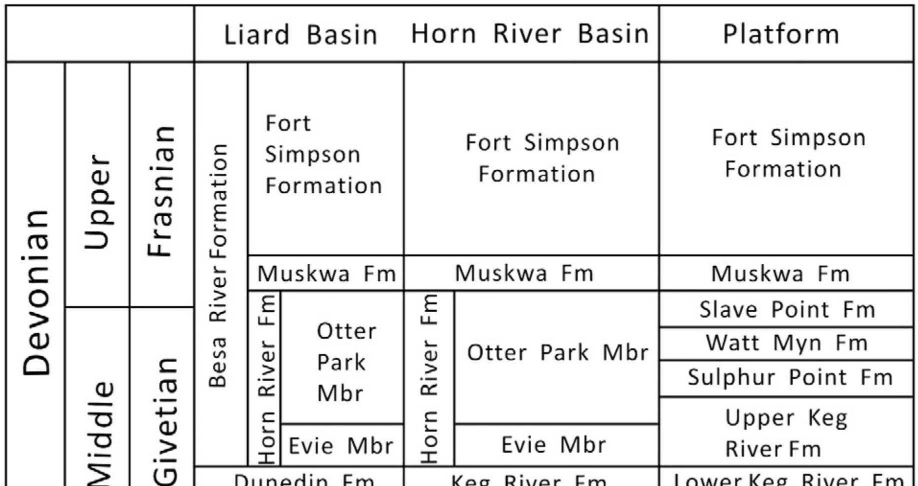

Fig. 2. Middle and Upper Devonian stratigraphy of the Liard Basin, Horn River Basin and Cordova Embayment (modified after Ferri et al., 2011).