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Research paper

The lithofacies and reservoir characteristics of the Upper Ordovician and Lower Silurian black shale in the Southern Sichuan Basin and its periphery, China

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ABSTRACT

The black shale of the Upper Ordovician and Lower Silurian is a significant target for shale gas exploration in the Southern Sichuan Basin. In this study, we introduced a lithofacies classification for shale based on rock mineral composition. Because the pore structure of gas shale reservoirs are complex and greatly affect the gas storage and transport in shale, four different methods of low-pressure nitrogen gas adsorption, high-pressure mercury intrusion, scanning electron microscopy (SEM) and gas expansion methods were used to investigate the reservoir pore structure and storage space. Combined with X-ray diffraction, total organic matter content (TOC), gas content, methane adsorption, porosity and permeability and wireline data, the key factors that affect shale gas content and storage of shale gas were analyzed.

According to our shale classification, three main lithofacies, i.e., calcareous mudstone (CM), high calcareous mixed mudstone (HCMM) and low calcareous mixed mudstone (LCMM), were identified in our study area. The experiment indicates that the shale has a high TOC, thermal maturity and gas content. The methane adsorption isotherms show that the sorbed gas content has a positive correlation with TOC. Difference of TOC between the three is small. Nitrogen adsorption indicates that mesopores dominate the shale pore composition and organic matter is the main source of mesopores. Mercury injection shows that the macropore volume accounts for approximately 14–22% of the total pore volume. No obvious pore structure differences were found for different lithofacies. However, taking the porosity into consideration, LCMM has the largest macropore volume. The SEM observations revealed that organic matter pores, interparticle pores and intraparticle pores are the main pore types. Interparticle pores mainly develop in LCMM which has a relatively high quartz and low carbonate content, it may be the major reason for high porosity, high macropore volume, and high free gas content of LCMM. Free gas and absorbed gas are the major storage form of shale gas. Given similar temperature and pressure conditions, the total organic matter content is the major factor that affects the adsorbed gas content. Therefore, with high free gas and adsorbed gas content, LCMMs with high total organic matter contents would be the most favorable type of lithofacies in this region.

1. Introduction

Due to the technological innovations of horizontal drilling and hydraulic fracturing, gas production from shale has dramatically improved (Wang and Carr, 2012a, b; Curtis, 2002, 2012; Clarkson et al., 2012a). The recent frontier research on gas shale has focused on lithofacies classification (Hickey and Henk, 2007; Loucks and Ruppel, 2007; Dong et al., 2015), lithofacies identification (Wang et al., 2013, 2014a; Chang et al., 2000, 2002), depositional environments (Stow et al., 2001; Gross et al., 2015) and reservoir characteristics (Loucks et al., 2009, 2012; Curtis et al., 2012; Cao et al., 2015). Lithofacies and reservoir characteristics are two important focuses in the study of gas shale.

Lithofacies, the basic properties of rocks, has been used in

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geology, stratigraphy and sedimentology for more than seventy years (Wang and Carr, 2012b). It has a close connection with mineral components, organic matter (Wang and Carr, 2012a, b) and reservoir properties (Chang et al., 2002; Jungmann et al., 2011). A considerable amount of lithofacies research has been conducted in carbonate and siliciclastic reservoirs, in which wireline logs have been widely employed for carbonate and siliciclastic lithofacies identification (Chang et al., 2000; Saggaf and Nebrija, 2003). A sound understanding of the connection between shale lithofacies and reservoir ability could provide guidelines for making modest assessments of undiscovered hydrocarbon resources and designing proper exploration programs. A limited number of shale reservoir lithofacies studies have focused on the Barnett Shale, Marcellus Shale, New Albany Shale, and little concerns on the Upper Ordovician and Lower Silurian shale in the Southern Sichuan Basin.

Shale reservoirs are characterized as a self-contained source reservoir system. Abundant gas can be stored in pores and fractures in the form of free gas, absorbed gas and solution gas (Curtis, 2002; Ross and Marc Bustin, 2007), free gas and sorbed gas are two major forms (Labani et al., 2013). Shale reservoirs usually have extremely low permeability, relatively low porosity and contain extensive nanopores, the pore characterization and pore structure is of great significance for gas storage and flow capacity (Ross and Marc Bustin, 2009; Slatt and O'Brien, 2011; Wang et al., 2014a,b; Yang et al., 2014). To reduce exploration risks and achieve economical production, it is important to understand the pore structure, sorption and potential gas capacities of shale reservoirs (Ross and Marc Bustin, 2007, 2009; Yang et al., 2014). The International Union of Pure and Applied Chemistry (IUPAC) made a pore classification based on pore diameter: micropores (<2 nm), mesopores (2–50 nm) and macropores (>50 nm). Shale has a wide pore size distribution ranging from micropores to mesopores and macropores (Loucks et al., 2009). Loucks et al. (2012) created a descriptive classification for matrix-related pores, interparticle pores found between particles and crystals, intraparticle pores located within particles and organic matter pores located within organic matter. Assessments of pore features are typically made by quantitative and visual qualitative analyses (Clarkson et al., 2012a, 2012b; Wang et al., 2014b). FE-SEM images are the most common way to qualitatively characterize pore systems (Curtis et al., 2012). Quantitative analyses include high-pressure mercury intrusion (HPMI), low-pressure nitrogen and CO_2 gas adsorption (Clarkson et al., 2012b). Low-pressure nitrogen and CO_2 gas adsorption were used for micro-mesopore analysis, and high-pressure mercury was used for macropore characterization (Rouquerolt et al., 1994).

In China, the potential shale gas resources could reach approximately 26×10^{12} m^3 (Chen et al., 2011), and increasing shale gas exploration has been conducted in Sichuan Basin, from which the upper Ordovician Wufeng shale and Lower Silurian Longmaxi shale have been identified as major exploration targets because of their high organic matter abundance, considerable thickness and high maturity (Chen et al., 2011, 2014; Cao et al., 2015). However, to date, a lithofacies classification has not been performed, which could directly reflect reservoir and pore structure. The major goals of our work are to construct a systematic classification for the upper Ordovician Wufeng shale and Lower Silurian Longmaxi shale, which is useful for reservoir comparisons, and to provide further theoretical support for future shale gas exploration in similar basins.

2. Geologic setting and stratigraphy

The Sichuan Basin is a tectonically stable sedimentary basin, with an area of 180×10^3 km^2. It is located in southwestern China bordered by the Micang-Daba Mountains to the north, the Songpan-Ganzi Terrane (SGT) and Longmen Mountains to the west and the Xuefeng Mountains to the east. The study area is located in the Southern Sichuan Basin (Fig. 1). The Sichuan Basin underwent two tectonic deposition stages, the Sinian-Middle Triassic passive continental margin stage and the Late Triassic-Eocene foreland basin stage (Liang et al., 2014). A series of tectonic movements formed the current structural framework. The Sichuan Basin is covered by the strata from the Neoproterozoic to the Quaternary (Liang et al., 2014; Guo et al., 2014). The Sinian-Middle Triassic deposits mainly consist of thick marine carbonates. In the late Triassic, influenced by the closure of the Palaeo-Tethys Ocean and the subduction of the oceanic crust of the Yangtze Plate, the Sichuan Basin evolved from marine-terrigenous transitional deposition to terrigenous clastic rocks. In the late Ordovician and early Silurian, two third-scale global transgressions occurred, resulting in sedimentation of the Wufeng and Longmaxi shale (Guo et al., 2014).

The Wufeng and Longmaxi shales are widely distributed in the study area. The Wufeng shale has a thickness ranging from 5 to 11 m. The lower Wufeng shale is composed of a series of graptolite-rich black shale. The Guanyinqiao Member, which is the upper part of the Wufeng shale, has a thickness of approximately 0.2–0.6 m and higher calcium content. The Longmaxi shale also has a large distribution, with a considerable thickness of approximately 200 m. The lower Longmaxi shale also contains graptolite-rich black shale and high total organic matter content, whereas the upper Longmaxi shale consists of gray and sandy shale, with low total organic matter content. Our study interval includes the Wufeng and lower Longmaxi black shale, with a thickness of approximately 40 m and abundant organic matter.

3. Samples and methods

A total of 138 core samples collected in the study area were used to analyze the geochemical and mineral characteristics. The gas content determination of 35 samples was performed when a fresh core was taken out. Eighteen core plugs were used for helium porosimetry and nitrogen permeability. Then, they were prepared as small blocks, with the remaining offcuts and other samples crushed to powder with a diameter of less than 250 μm for the total organic carbon (TOC) content measurement and low temperature nitrogen adsorption. Mercury intrusion was performed using a 9510-IV porosimeter. The porosity was tested by a ULTRAPORE-200A using the helium expansion method. Permeability was measured using an ULTRA-PERMTM200. The TOC of all samples were measured using a LECO CS-230 carbon analyzer. A RINT-TTR3 was used for X-ray diffraction at a voltage of 45 kV and a current of 100 mA to test the mineral content of all samples. Ar-ion-beam milling could produce a relatively flat surfaces which are suitable for highmagnification imaging. In our study, eight samples processed by an Ar-ion-beam were observed using FEI Quata200F equipped with an energy-dispersive spectrometer (EDS). Another eight unmilled samples were observed using a HITACHI S-4800 to determine the microstructure and morphology of the minerals and organic matter.

The thermal maturity was tested using optical microscopy. The most favored way of assessing the thermal maturity is vitrinite reflectance (VR_o), however, Longmaxi shale contain no vitrinite (Liang et al., 2014) for VR_o measurement. Because VR_o has a strong relationship with bitumen reflectance (BR_o) (Jacob, 1989; Schoenherr et al., 2007), we were able to obtain VR_o using Schoenherr's equation in cases in which solid bitumen was present and vitrinite was absent. The equation is as follows: