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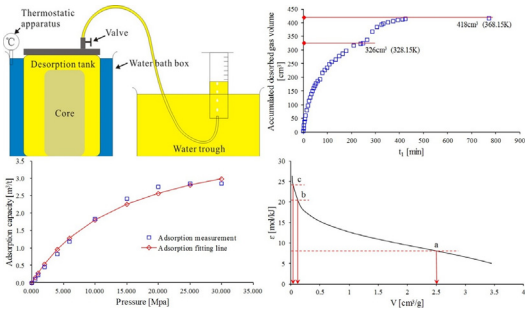
A novel method to estimate subsurface shale gas capacities

Hexin Huang[a,b], Wei Sun[a,b], Fengyang Xiong[c], Lei Chen[d,*], Xin Li[e], Tian Gao[f], Zhenxue Jiang[d], Wei Ji[g], Yanjun Wu[a,b], Jin Han[h]

[a] State Key Laboratory of Continental Dynamics of Ministry of Geology, Northwest University, Xi'an 710069, China
[b] Department of Geology, Northwest University, Xi'an 710069, China
[c] School of Earth Sciences, The Ohio State University, Columbus, OH 43210, USA
[d] State Key Laboratory of Petroleum Resources and Prospecting, China University of Petroleum, Beijing 102249, China
[e] No. 5 Gas Production Plant, PetroChina Changqing Oilfield Company, Xi'an 710018, China
[f] No. 6 Gas Production Plant, PetroChina Changqing Oilfield Company, Xi'an 710018, China
[g] Changqing Division of China Petroleum Group Logging Co., Ltd., Xi'an 710201, China
[h] School of Petroleum Engineering and Environmental Engineering, Yan'an University, Yan'an 716000, China

GRAPHICAL ABSTRACT



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ABSTRACT

In order to evaluate shale gas content more accurately, a novel method for estimation of shale gas content in place is proposed based on the Polanyi adsorption potential and the London dispersion potential energy (P-L method). A series of integrated analyses were conducted on one shale core sample from the 7th member of Yanchang Formation (Chang 7 Member) in Ordos Basin, NW China, including on-site canister desorption tests, high-pressure methane adsorption isotherms, helium-based porosimetry, and gas composition analysis. On the basis of our experimental results, the P-L method and the commonly used 'direct' (based on measurement of desorbed gas) and 'indirect' (based on measurement of pore volume and state of equation) methods were used, respectively, to model the in-situ shale gas content. The results show that the shale gas content under the same experimental conditions predicted by the P-L method was 4.398 cm^3/g and that by the direct method was 1.668 cm^3/g, which is significantly lower. Meanwhile, those under the same lab conditions by the P-L method and the indirect method are 3.954 cm^3/g and 3.820 cm^3/g, respectively. Direct methods are more sensitive to human errors than the indirect methods, remove the impact of arbitrary factors by operators, and can shed light on the actual shale gas content in place based on the measured properties of samples. The P-L method is supported by well-developed theoretical basis. Through comparison between all these three methods, the results by

* Corresponding author.
E-mail address: chenlei19880804@163.com (L. Chen).

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the P-L method can be reasonable and practicable, and could be used to recover shale gas content in-situ during the shale gas resource potential assessment.

1. Introduction

Consisting mainly of alkane and containing less sulfide, shale gas is considered as a cleaner energy resource than coal and oil [1–3]. Its exploration and development in North America has been highly successful in the past decades [1,4–7]. Recently, China has learned experiences from the success in the United States and been engaged in the shale gas exploration and development since 2009 owing to the increasingly domestic demand of energy [8–14]. Accurate assessment of shale gas content in place is a prerequisite for evaluation of shale gas resource potential, recoverability, and productivity [4,12,15,16].

There are two categories of commonly used methods for estimation of shale gas content in place. One is direct [16], while the other is indirect [17].

Direct methods to estimate the shale gas content divide shale gas into *desorbed gas*, *residual gas*, and *lost gas* [18]. Desorbed gas is the gas collected at a temperature in the on-site desorption tank, residual gas is the gas obtained by crushing the desorbed core, and lost gas refers to the gas loss from the very beginning of drilling core to being sealed in the desorption canister. Generally, lost gas contributes the largest error in the direct methods. Accordingly, several methods have been proposed to estimate the lost gas, including the modified United States Bureau of Mines (USBM) method [19], the Smith-Williams method [20,21], and a curve fitting method [22]. Among these, the USBM method has been the most widely used in the coal bed methane (CBM) and shale gas industries [16].

Indirect methods divide shale gas into *free gas, dissolved gas,* and *adsorbed gas*. Free gas is the gas in the bulk state stored in the pore space, which is obtained from the pore volume and an equation of state. Dissolved gas is obtained by empirical relations, which is in oil, water, kerogen, bitumen and so on [23]. Finally, adsorbed gas is the gas on the surface of mineral particles, especially organic matter (i.e., kerogen and bitumen) and clay minerals, which is obtained by isothermal adsorption of methane based on Langmuir or other adsorption theories [17,24]. Indirect methods have been recently widely used in investigating adsorption capacity of shales [4,11,25–28].

However, both direct and indirect methods have their limitations. For instance, the modified USBM method, representative of direct methods, is prone to large errors in the calculation of lost gas because of the following assumptions: the lifting time of drilling bit is very short; the temperature and diffusion rate during the estimation of cores are constant; and the diffusion of gas from the center to the surface of cores is instantaneous. These assumptions can never be achieved during the coring of shales.

In the indirect methods, the experimental condition for adsorbed gas is different from the reservoir conditions. For instance, in the experimental settings, crushed shale core samples contain less water vapor occupying adsorption sites [29,30], and adsorption sites occupied

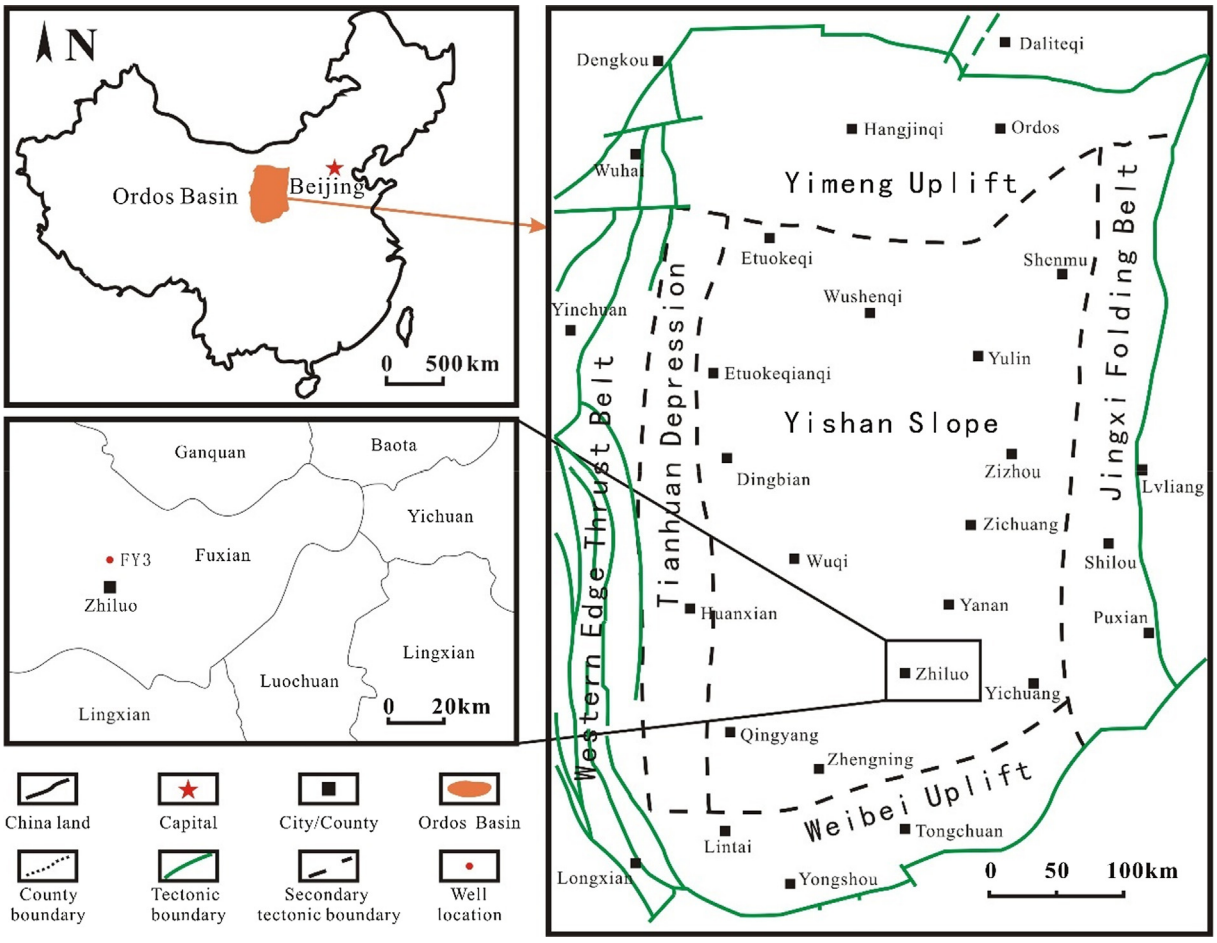

Fig. 1. Geological map of study area and location of coring wells.