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A new analytical method based on pressure transient analysis to estimate carbon storage capacity of depleted shales: A case study

Zhiming Chen*, Xinwei Liao, Xiaoliang Zhao, Xiaoxu Feng, Jiali Zang, Liping He

College of Petroleum Engineering, China University of Petroleum, 102249 Beijing, China

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A B S T R A C T

In this paper, based on pressure transient analysis (PTA), a quick and reasonable analytical method for estimating CO_2 storage capacity of depleted shales is introduced. Firstly, a CO_2 seepage model for an injection well with constant injection rate is proposed in consideration of Knudsen diffusion, gas adsorption, and stress-sensitivity effect of permeability. Then, combined with Laplace transform and Pedrosa's substitution, the seepage model is solved and the transient pressure solutions of the injection well are obtained. At last, with these solutions, CO_2 storage capacity can be easily estimated at an arbitrary injection pressure. To verify the proposed approach, a derived case from the New Albany Shale is studied. Furthermore, on the basis of the case, the influences of some critical parameters on CO_2 storage capacity are analyzed.

The research results demonstrate that there is a good agreement between the proposed method and the numerical method, with the maximum difference smaller than 1.5%. In addition, sensitive analysis shows that CO_2 storage capacity increases with the increasing of stress-sensitivity coefficient, adsorption index, Knudsen diffusion coefficient and constrained injection pressure; it decreases with the increasing of storage ratio. It is also found that as constrained injection pressure increases, the effects of the parameters above on the storage capacity become more obvious.

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1. Introduction

In previous work, researchers were inclined to rely on conventional geological sequestrations, such as saline aquifers, unminable coal seams, and depleted carbonate reservoirs for CO_2 storage (Bachu, 2000; Bachu et al., 1994; Busch et al., 2008; De Silva and Ranjith, 2012). Only few people, till recently, have attempted to transform shale formations into repositories (Jiang et al., 2014; Tao and Clarens, 2013). It is pointed out in many published works that, kerogen contained in shale could result in a significant gas adsorption amount (Akkutlu and Fathi, 2011; Ambrose et al., 2010; Kang et al., 2010; Loucks et al., 2009; Sondergeld et al., 2010; Wang and Reed, 2009). The kerogen acts as a molecular sieve allowing the linear molecule CO_2 to reside in small pores and prohibiting other naturally-occurring gases from entering such pores (Kang et al., 2010). This provides valuable views as well as strong supports for the feasibility of CGS in shales (Clarkson et al., 2012). Meanwhile, storing CO_2 in shale formations could enhance methane recovery, reduce leakage risk and save storage cost which makes the estimation of CO_2 sequestration capacity in shales a hotspot of relevant studies (Godec et al., 2013; Tao and Clarens, 2013).

By far, several methods have been proposed for evaluating the CO_2 storage capacity in shales, and they can be simply classified into three groups: volume based method, production based method, and numerical method.

The volume based method is simple and convenient. Busch et al. (2008), Kang et al. (2010) and Tian et al. (2013) experimentally measured the storage volume of CO_2 in shale samples from Muderong (Australia), Barnett (USA), and Sichuan (China). Then, the CO_2 storage capacity can be easily calculated by incorporating the whole volume of shale formation. However, for heterogeneous or geological-uncertainty shale reservoirs, the reliability of volume based method may be reduced.

The production based method was firstly introduced by Tao and Clarens (2013) to evaluate CO_2 sequestration capacity of the Marcellus Shale. In their work, they estimated the CO_2 storage capacity based on historical and projected CH_4 production data. The production based method is attractive due to the rapid process. Unfortunately, its accuracy may decrease when poor-quality production data is applied (Middleton et al., 2012).

A series of numerical simulation studies were also performed on in-house or commercial simulation simulators to appraise the

* Corresponding author at: China University of Petroleum, No. 18, Fuxue Road, Changping, Beijing, China.
E-mail address: zhimingchn@163.com (Z. Chen).

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Nomenclature

a	adsorption index, dimensionless
C_D	wellbore storage coefficient, dimensionless
S	wellbore skin factor, dimensionless
C_g	CO_2 compressibility, MPa^{-1}
K_n	Knudsen number, dimensionless
D_K	Knudsen diffusion coefficient, $m^2\,h^{-1}$
F	number of fractured stages for horizontal fractured well, integer
M	number of segments of each fracture, integer
i,l	fracture number, integer
j,k	fracture segment number, integer
h	formation thickness, m
L	length, m
K	permeability, Darcy (D)
M_g	molar mass of CO_2, kg/mol
m	pseudo-pressure, MPa^2/mPa s
p	real pressure, MPa
q	CO_2 flow rate, m^3/d
Q_T	CO_2 injection volume, m^3
R_m	matrix radius, m
r_m	radial distance in matrix system, m
r_s	spherical distance in natural fracture system, m
r_c	cylinder distance in bounded system, m
R	gas constant, $J\,mol^{-1}\,K^{-1}$
t	injection time, h
T	temperature, K
T_D	total injection time, K
v	CO_2 flow velocity, m/h
V	CO_2 concentration, sm^3/m^3
Z	CO_2 Z-factor, dimensionless
s	Laplace transformation variable, dimensionless
x,y,z	coordinates, m
$I_n(x)$	first kind of modified Bessel functions
$K_n(x)$	second kind of modified Bessel functions
Greek	
ρ	density, ton/m^3
ϕ	porosity, fraction
μ	viscosity, mPa s
α	permeability modulus, MPa^{-1}
γ	modified permeability modulus, MPa^{-1} s
ω	storage ratio, fraction
Subscript	
con	constrained
D	dimensionless
E	external
f	fracture
i	initial
in	injection
L	Langmuir
m	matrix
sc	standard condition
w	wellbore
H	horizontal
1	pressure rise in infinite boundary
2	pressure rise in infinite boundary
Superscript	
$\bar{}$	Laplace transform
$\hat{}$	transient

CO_2 storage capacity (Dahaghi, 2010; Godec et al., 2013; Sun et al., 2013; Jiang et al., 2014; Schepers et al., 2009; Liu et al., 2013). With this numerical method, more accurate and convincing results can be obtained. However, the numerical calculation process is complicated, time-consuming and expensive (Chen et al., 2014). In addition, the detailed data required by numerical method is site-specific, and it may not be suitable for other situations.

Considering the disadvantages of existing methods, a more quick and reasonable estimation method is in great need. Zhou et al. (2008) and Birkholzer et al. (2009) developed analytical methods related to pressurization for rapidly estimating CO_2 storage capacity in saline aquifers. The quick-assessment methods derived from the fact that the volume of displaced brine is equal to that of cumulative injected CO_2, which can be calculated by average pressure buildup in the storage formations. These methods provided key references for later work on evaluating CO_2 storage capacity in saline aquifers (Ganjdanesh et al., 2015; Mathias et al., 2009; Song et al., 2015; Thibeau et al., 2014). Inspired by the rapid and reasonable approaches, a new analytical method based on transient pressure buildup of injection well is proposed for CO_2 storage in shales.

In this study, a PTA method is employed to estimate CO_2 storage capacity in depleted shale reservoirs. A derived case from the New Albany Shale is studied for method verification. Then sensitivity analysis is performed on several critical parameters which closely affect CO_2 storage capacity. The study also proposes a quick and reasonable access to CO_2 sequestration potential estimation, and we try to introduce a perspective for the reutilization of depleted shale reservoirs which is considerably beneficial to our environment.

2. Methodology for estimating CO_2 storage potential in depleted shales

The methodology for evaluating CO_2 sequestration capacity in depleted shales is organized as following:

(1) Building a physical model for CO_2 injection or storage.
(2) Reciting CO_2 basic equations.
(3) Establishing and solving the CO_2 seepage model in infinite shale formation through the basic equations.
(4) Achieving the solution of CO_2 seepage model in bounded cylindrical formation by using superposition and imaging based on 3.
(5) Obtaining the transient pressure solution of the injection well by applying integration and Stehfest numerical inversion.
(6) Calculating CO_2 storage capacity with constrained injection pressure.

2.1. Physical model

Fig. 1a shows an injection well located in the center of the depleted shale formation. Many researches (Prats, 1961) pointed out the influence of the boundary shape on wellbore pressure is insignificant. Thus, we assume a cylinder boundary for the shale formation. The injection well is a multiple fractured horizontal well (MFHW), which is the main tool for shale gas production before the depletion of shale reservoirs. Other assumptions of the physical model are as following:

- The shale formation has a uniform depleted pressure p_i and a fixed temperature T.
- Fractures along the MFHW, with length of L_H, are uniform, and they penetrate the shale formation completely.
- The total injection rate of CO_2 is constant, but the CO_2 flow rate is non-uniform in each fracture.

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