

Original Paper

A fast bidirectional pressure decay method for measuring permeability and porosity in tight rocks

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ARTICLE INFO

Article history:

Received 20 October 2025

Received in revised form

15 April 2026

Accepted 26 June 2026

Available online 1 July 2026

Edited by Xiu-Fang Hu

Keywords:

Tight rocks

Nanoporous

Permeability

Porosity

Bidirectional pressure decay

ABSTRACT

Permeability and porosity parameters of tight rocks are of crucial importance to the applications ranging from extraction of geothermal and hydrocarbon resources to subsurface storage of carbon, nuclear waste, and hydrogen. Separate measurements of permeability and porosity, however, cost time and can produce erroneous results. We designed a bidirectional pressure decay (BPD) experiment to assess the porosity and permeability at the same time. A pressure differential was applied between a gas chamber and a core sample's two end surfaces. The pressure in chamber (p_c) was recorded with time until the pressure reached an equilibrium pressure (p_e). The porosity of the core sample was computed based on the gas mass amount in chamber and core sample. The mathematical model was derived for this BPD method. The exact solution of the model was validated with numerical results. The late-time solution shows that the difference between p_c and p_e has a linear correlation with time on a semi-logarithmic plot. The permeability was produced based on the slope of the linear regression. Applying confining pressures ranging from 12 MPa to 22 MPa, the BPD method was implemented for estimating the porosity and permeability of a shale sample. The results suggest that it can efficiently measure the stress-dependent porosity (2.23%–2.61%) and permeability (2.21×10^{-5} – 3.72×10^{-5} mD) of the sample. This technique has two main advantages: On the one hand, it is highly efficient due to the bidirectional flow pattern, allowing gas to enter the core through both end surfaces and drastically reducing experimental duration; On the other hand, measuring porosity and permeability from a single experiment is more straightforward and precise than testing them separately.

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1. Introduction

An abundance of tight formations, such as tight sandstone, shale, and limestone, has gained widespread attention in recent years (Dong et al., 2025; Geng et al., 2023; Hu et al., 2024; Zhang et al., 2020b). They can bear a vast amount of energy and

resources, such as geothermal energy in granite formations (Kumari et al., 2017) and hydrocarbons in shale, limestone, and sandstone formations (Liu et al., 2022; Ma and Zoback, 2017; Wang et al., 2023; Zhao et al., 2022). Those low-permeability formations could be feasible for subsurface CO₂ storage (Xie et al., 2023; Zhao et al., 2025a), underground hydrogen storage (Pan et al., 2024), and nuclear waste disposal (Fairhurst, 2004; Popov et al., 2023) due to the fluid flow being extremely slow. An accurate characterization of porosity and permeability is critical for the geological processes in those formations (Liu et al., 2025; Sun et al., 2016; Zhao et al., 2025b). However, precisely evaluating these petrophysical properties in unconventional tight reservoirs presents significant challenges due to their unique pore structures and extreme

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Peer review under the responsibility of China University of Petroleum (Beijing).

tightness (Vafaie et al., 2021; Zhou et al., 2025). Recent reviews have further emphasized that the accurate measurement of permeability in such low-permeability media remains a primary focus of ongoing experimental efforts and technical refinements (Gong et al., 2023; Li et al., 2025).

The steady-state method is one of the most commonly used methods to determine the permeability of rock cores in laboratories (Dong et al., 2012). For tight rocks, however, the fluid flow rate is extremely small and difficult to detect, leading to inaccurate results (Liu et al., 2024). The pulse decay methods are the most commonly used techniques to determine the permeability of tight rocks (Sander et al., 2017). Brace et al. (1968) proposed a pulse decay method by creating a pressure increase in the upstream reservoir and determining the permeability of granite. This method is based on the assumption that the storage volume of the sample is negligible and the pressure gradient within the sample remains constant. It was refined by taking into account the sample's particular storage, and an iterative method of curve-fitting the experimental data was used to assess its permeability (Hsieh et al., 1981; Neuzil et al., 1981). The restrictions on the volumes of upstream and downstream reservoirs were further altered to produce a more straightforward approximation of the permeability equation to achieve an easier solution (Dicker and Smits, 1988). This work was then improved by using a much simpler late-time solution (Jones, 1997). This late-time solution considerably enhanced earlier work and used a simple data processing method: a semi-logarithmic depiction of the differential pressure with time. Furthermore, combining laboratory methods with statistical analyses, like multiple linear regression, has been shown to improve permeability prediction accuracy for tight shale gas resources (Vafaie et al., 2021). However, the experimental time to measure the permeability of tight rocks is still long. To reduce experimental time, the permeability can be measured using an exact early-time solution before the upstream pressure pulse reaches the downstream reservoir to shorten the experimental duration (Wang et al., 2021a). Nonetheless, the permeability derived from such methods remains contingent upon a precise assessment of the individual pore volumes. Typically, these pore volumes are evaluated using gas-volumetric methods based on the Boyle-Mariotte law, alongside non-stationary nitrogen filtration to determine absolute permeability (Ghasemi and Javid, 2026).

Permeability measurements can be conducted using the Gas Research Institute (GRI) approach, which is a variation of the pressure pulse decay method (also called the pressure fall-off method) (Luffel et al., 1993). This method involves quickly drawing one complete vessel's core surface down to a vacuum, from which the permeability can be derived from the data on the pressure fall. The procedure for testing unconfined core plugs was further refined (Cui and Brezovski, 2013), and the permeability was assessed in the presence of in-situ stress (Yang et al., 2015). In this context, core-scale experiments, such as seepage tests and X-ray CT, are also crucial for quantifying permeability changes with hydrate saturation and stress sensitivity (Li et al., 2025). Furthermore, researchers utilize permeability and NMR experiments under confining pressure to investigate the relationship between stress-dependent permeability and pore structure evolution in tight sandstone and shale (Li et al., 2024; Wang et al., 2026). The pressure decay method was further modified especially to measure the core pore volume at the same time (Cui et al., 2010). Furthermore, the permeability was calculated while accounting for the adsorption impact when measuring the pulse-decay of crushed samples and cores (Cui et al., 2009). Additional modifications were made to the pressure decay approach in order to assess tight cores' radial permeability (Yang et al., 2016). To shorten the test duration, modifications of GRI approach can be

used to quickly test the permeability of crushed samples or powders (Jia et al., 2021). However, because the crushed samples avoid fluid flow in microfractures, the permeability of crushed samples could show significant differences with that from core plugs (Peng and Loucks, 2016). This discrepancy can be attributed primarily to two factors. First, the GRI method typically employs low gas pressures (below 100 psi), which can induce the Knudsen diffusion effect (Liu et al., 2018). Second, the presence and influence of induced fractures must be considered (Zhang et al., 2020a). Recent experimental advancements have focused on developing novel systems and techniques to address the complex evolution of permeability under specific scenarios, such as unconventional oil and gas extraction and natural gas hydrate production (Kan et al., 2025; Li et al., 2025; Shang et al., 2026; Yang et al., 2025; Zhou et al., 2024). Nevertheless, the fundamental premise of all these advanced investigations remains the accurate and efficient measurement of permeability.

Over the past few decades, several permeability estimation techniques for tight rocks based on unidirectional flow patterns have been proposed. The permeability test duration continues to be lengthy. The porosity data from different tests are required by the widely used pressure pulse decay method, which may lead to inaccurate permeability results (Sun et al., 2020). Therefore, we developed a novel and efficient bidirectional pressure decay technique that permits gas to flow from the core sample's two end surfaces into its center. This approach not only significantly shortens the experimental time but also enhances the reliability of the results by enabling simultaneous determination of porosity and permeability.

2. Experimental methodology

2.1. Core sample preparation

The core sample used is black shale, extracted from the Longmaxi Formation in the Sichuan Basin of China at a depth of roughly 2252 m. Extremely low porosity and permeability were characteristics of the Longmaxi shale. The core sample was cut into 2.45 cm in diameter and 3.35 cm in length. To eliminate any remaining water content, the core sample was dried in an oven set at 80 °C for three days. The core sample was placed into a core holder, which can provide confining pressure to the side and two end surfaces of the core sample, to assess the in-situ porosity and permeability.

2.2. Experimental procedures

Fig. 1 shows a schematic of the bidirectional pressure decay experiment. After calibrating the gas chamber volume, a leakage test was conducted. Since the tight sample has low porosity and the pressure decay method prefers a small gas chamber, no additional vessel was used in this study. The entire void volume of the pressure transducer, gas lines, and valves 2 and 3 is referred to as the gas chamber. The chamber's volume (V_c) is roughly 5.373 cm³. In an oven, the experiment's temperature was maintained at 20 °C. In this research, 99.99% pure helium was used as the test gas. In the setup, a gas cylinder is used to initially fill the system with helium. However, as the gas enters the testing system, the overall volume increases, causing the system pressure to drop slightly below the initial cylinder pressure. Furthermore, a gas cylinder cannot precisely regulate pressure. Therefore, a fluid-pressure hand pump is incorporated into the system to fine-tune and accurately raise the gas pressure to the predetermined target value.

The following is the set of procedures for this bidirectional pressure decay experiment:

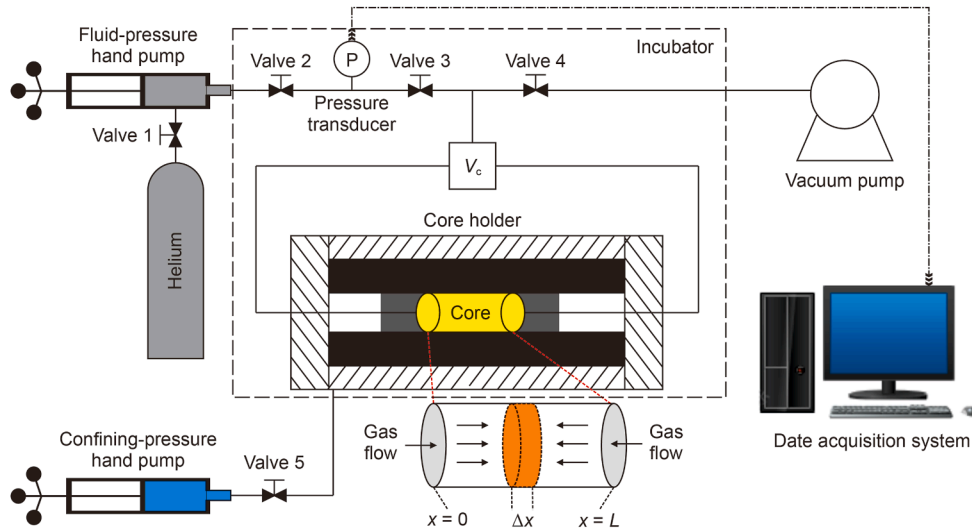


Fig. 1. Schematic diagram of the bidirectional pressure decay experiment (modified after Sun et al., 2016).

- (1) After inserting the core sample into the core holder, a confining-pressure hand pump was used to apply hydraulic confining pressure (C_p).
- (2) After vacuuming the experimental system for an hour to remove remaining air, valves 1, 2, and 3 were opened to fill the system with helium.
- (3) The valve 1 was closed. Using a fluid-pressure hand pump, the core sample was saturated with helium for 3 h at a pressure of p_1 .
- (4) The valve 3 was closed. The fluid-pressure hand pump's gas pressure was raised.
- (5) The valve 2 was closed and the valve 3 was open. The pressure in the gas chamber rose to p_0 , which is approximately 0.5 MPa higher than p_1 .
- (6) The pressure decline data in the chamber was collected by the computer until the core sample and chamber pressure reached the ultimate equilibrium pressure (p_e).

The design of the BPD method offers a key advantage in operational efficiency. By establishing a bidirectional flow and utilizing a small chamber volume, the pressure equilibrium is achieved much more rapidly compared to conventional unidirectional pulse-decay methods, significantly shortening the experimental duration.

3. Permeability and porosity from BPD method

3.1. Mathematical model

The diffusion-type pressure equation for one-dimensional gas flow in a core sample can be expressed as follows (Cui et al., 2009):

$$\frac{\partial^2 p(x, t)}{\partial x^2} = \frac{1}{D} \frac{\partial p(x, t)}{\partial t} \quad (1)$$

where x is the distance, t is time, and D is the apparent transport coefficient, which can be defined as

$$D = \frac{k_g}{\phi \mu C_g} \quad (2)$$

where k_g is permeability, ϕ is the porosity, μ is the gas viscosity, and C_g is the gas compressibility, which is written as follows:

$$C_g = \frac{1}{p} \left(1 - \frac{p}{z} \frac{\partial z}{\partial p} \right) = \frac{f_z}{p} \quad (3)$$

where z is the helium compressibility factor. The f_z is expressed as

$$f_z = 1 - \frac{p}{z} \frac{\partial z}{\partial p} \quad (4)$$

For the experimental configuration depicted in Fig. 1, the rate at which the gas leaves the chamber is always equal to the rate at which it enters the core plug over the surfaces at $x = 0$ and $x = L$. The gas amount in the chamber was written as

$$V_c \frac{dc_c}{dt} = -DA\phi \frac{\partial c}{\partial x} \Big|_{x=0} + DA\phi \frac{\partial c}{\partial x} \Big|_{x=L} \quad (5)$$

where c_c is the gas concentration in the chamber, c is the gas concentration in the sample's pores, and A is the end surface area of the core sample.

The modified gas state equations, which are displayed below, can be used to determine the gas pressure:

$$c_c = \frac{p_c}{z_{av}RT} \quad (6)$$

$$c = \frac{p}{z_{av}RT} \quad (7)$$

where p_c is the pressure in the gas chamber, p is the pressure in the core, R is the gas constant, T is the temperature, and z_{av} is the helium compressibility factor at average pressure in the core and gas chamber. For the pressure decay experiment, the average compressibility factor can be used because the pressure shift is small.

Substituting Eqs. (6) and (7) into Eq. (5) yields

$$\alpha L \frac{dp_c}{dt} = -D \frac{\partial p}{\partial x} \Big|_{x=0} + D \frac{\partial p}{\partial x} \Big|_{x=L} \quad (8)$$

where α is the ratio of chamber volume and pore volume.

The α is expressed as

$$\alpha = \frac{V_c}{LA\varphi} \quad (9)$$

where V_c is the chamber volume.

The pressure on the two surfaces is known to be equal. The gas, however, moves in the opposite direction. The following is a relationship for the pressure gradient on two end surfaces:

$$\left. \frac{\partial p}{\partial x} \right|_{x=0} = - \left. \frac{\partial p}{\partial x} \right|_{x=L} \quad (10)$$

3.2. Boundary and initial conditions

The following are the boundary conditions on the core plug's two end surfaces:

$$\begin{cases} p_{(x=0,t)} = p_c \\ p_{(x=L,t)} = p_c \end{cases} \quad (11)$$

$$\begin{cases} \alpha L \frac{dp_c}{dt} = -2D \left. \frac{\partial p}{\partial x} \right|_{x=0} \\ \alpha L \frac{dp_c}{dt} = 2D \left. \frac{\partial p}{\partial x} \right|_{x=L} \end{cases} \quad (12)$$

The pressure decay experiment provides information about the initial gas pressure within the chamber. The initial pressure conditions in the core and chamber are therefore expressed as:

$$\begin{cases} p_{(x,t=0)} = p_1 \\ p_{c(t=0)} = p_0 \end{cases} \quad (13)$$

3.3. Permeability determination

Eq. (1) can be solved by converting it into an ordinary differential equation using the Laplace transform. The Laplace transform for comparable diffusion issues has been given in previous work (Carslaw and Jaeger, 1959). The initial condition in Eq. (13), along with the integration by parts theorem, allows us to rewrite the Laplace transform as:

$$D \frac{d^2 \bar{p}}{dx^2} - s\bar{p} + p_1 = 0 \quad (14)$$

where $\bar{p}$ is the Laplace transform of pressure and s is the Laplace transform parameter.

Eq. (12) displays the relevant boundary conditions, and their Laplace transforms are as follows:

$$\alpha L s \bar{p} - 2D \frac{d\bar{p}}{dx} = \alpha L p_1, \quad x = 0 \quad (15)$$

$$\alpha L s \bar{p} + 2D \frac{d\bar{p}}{dx} = \alpha L p_1, \quad x = L \quad (16)$$

A similar diffusion problem in a planar sheet with different initial circumstances was studied (Crank, 1979). By first solving the ordinary differential Eqs. (14)–(16), and then conducting the inverse Laplace transform, the case's solution can be obtained. The following expression represents the pressure within the core plug:

$$\frac{p - p_1}{p_e - p_1} = 1 + \sum_{n=1}^{\infty} \frac{2(1 + \alpha)}{1 + \alpha + \alpha^2 \lambda_n^2} \frac{\cos\left(\lambda_n \left(\frac{2x}{L} - 1\right)\right)}{\cos \lambda_n} e^{-\frac{4D\lambda_n^2 t}{L^2}} \quad (17)$$

The λ_n denotes the n th positive root of

$$\alpha \lambda_n = -\tan \lambda_n \quad (18)$$

The bisection method is an efficient way to solve Eq. (18), which has infinite solutions. Applying mass conservation to the initial and equilibrium states results in

$$c_1 + \alpha c_0 = (1 + \alpha) c_e \quad (19)$$

where c_1 is the initial gas concentration in the core, c_0 is the initial gas concentration in the chamber, and c_e is the gas concentration at the equilibrium state.

Eq. (19) is then rewritten as:

$$\frac{p_1}{z_{av}RT} + \frac{\alpha p_0}{z_{av}RT} = (1 + \alpha) \frac{p_e}{z_{av}RT} \quad (20)$$

where z_{av} is the average compressibility factor at the average pressure (p_{av}).

$$p_e = \frac{p_1 + \alpha p_0}{1 + \alpha} \quad (21)$$

Substituting Eq. (21) into Eq. (17) yields

$$p = p_1 + \frac{\alpha(p_0 - p_1)}{(1 + \alpha)} \left(1 + \sum_{n=1}^{\infty} \frac{2(1 + \alpha)}{1 + \alpha + \alpha^2 \lambda_n^2} \frac{\cos\left(\lambda_n \left(\frac{2x}{L} - 1\right)\right)}{\cos \lambda_n} e^{-\frac{4D\lambda_n^2 t}{L^2}} \right) \quad (22)$$

At $x = 0$, substituting Eqs. (21) and (22) into Eq. (12) yields

$$\alpha L \frac{dp_c}{dt} = -4D(p_0 - p_1) \sum_{n=1}^{\infty} \frac{\lambda_n^2 \alpha^2}{(1 + \alpha + \alpha^2 \lambda_n^2)L} e^{-\frac{4D\lambda_n^2 t}{L^2}} \quad (23)$$

Integrating Eq. (23) from $t = 0$ to infinity produces

$$\frac{p_0 - p_c}{p_0 - p_e} = 1 - \sum_{n=1}^{\infty} \frac{2\alpha(1 + \alpha)}{(1 + \alpha + \alpha^2 \lambda_n^2)} e^{-\frac{4D\lambda_n^2 t}{L^2}} \quad (24)$$

As the pressure in the chamber and the pressure on the core surface are equal, Eq. (22) and $x = 0$ can also be used to generate Eq. (23). The fractional pressure decrease in the chamber is represented by a parameter called F_D , which we define and write as:

$$F_D = \frac{p_0 - p_c}{p_0 - p_e} \quad (25)$$

At both the initial and ultimate equilibrium states, the total amount of gas in the chamber and core was identical.

The fractional pressure decrease (F_D) is then expressed as

$$F_D = 1 - \sum_{n=1}^{\infty} \frac{2\alpha(1 + \alpha)}{1 + \alpha + \alpha^2 \lambda_n^2} e^{-\frac{4D\lambda_n^2 t}{L^2}} \quad (26)$$

where t_D is defined as a dimensionless time, defined as

$$t_D = \frac{Dt}{L^2} \quad (27)$$

We use a late-time method for Eq. (26). The F_D in Eq. (26) is close to a late-time solution, as the t_D is large. The fractional pressure decrease using late-time solution is expressed as

$$F_{DL} = 1 - \frac{2\alpha(1+\alpha)}{1+\alpha+\alpha^2\lambda_1^2} e^{-4\lambda_1^2 t_D} \quad (28)$$

where λ_1 is the first positive root of Eq. (18) and it's a function of α .

The relationship between λ_1 and α is displayed in Fig. 2. Since the pore volume of tight rocks is quite small, the chamber volume should be constrained. The pressure shift is quite minor for a pressure decay experiment, and pressure reduction in the chamber will decrease as the α increases. As α goes to infinity, λ_1 goes to $\pi/2$. A greater pressure drop within the chamber is desired due to the constraint of a pressure transducer's precision. It is advised to use a value of less than 20 for a quick and precise testing.

Fig. 3 displays a comparison between the exact solution and the late-time solution. As the t_D is smaller than 0.03 one can see that the exact solution F_D and the late-time solution F_{DL} exhibit considerable deviations until they become almost equal. In contrast to other pressure decay methods, where the late-time solution and precise solution become identical at a t_D of 0.1 (Cui et al., 2009) and a t_D of 0.15 (Yang et al., 2015), this value is far smaller. This bidirectional pressure decay method favors the determination of the core sample's pore volume and reaches equilibrium quickly. It is conceivable to measure permeability using the late-time solution.

Eqs. (25) and (28) are then reformulated as

$$1 - F_{DL} = \frac{p_c - p_e}{p_0 - p_e} \quad (29)$$

$$\frac{p_c - p_e}{p_0 - p_e} = \frac{2\alpha(1+\alpha)}{1+\alpha+\alpha^2\lambda_1^2} e^{-4\lambda_1^2 t_D} \quad (30)$$

The logarithmical value of $p_c - p_e$ becomes a linear function of time, or t_D . We derive the subsequent results:

$$\ln(p_c - p_e) = -\frac{4D\lambda_1^2 t}{L^2} + \ln\left(\frac{2\alpha(1+\alpha)(p_0 - p_e)}{1+\alpha+\alpha^2\lambda_1^2}\right) \quad (31)$$

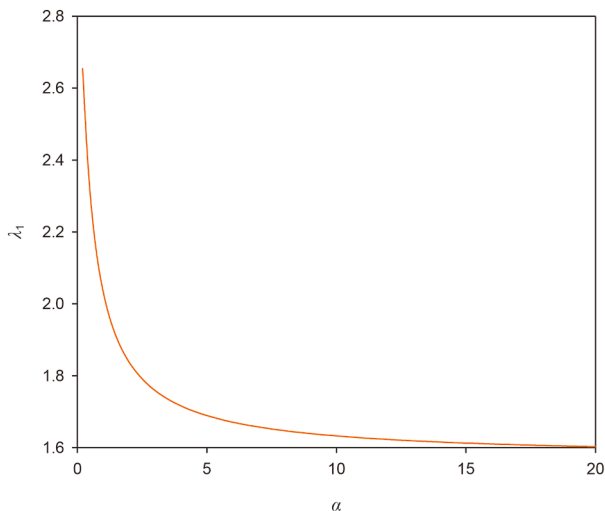


Fig. 2. Relationship between λ_1 and α .

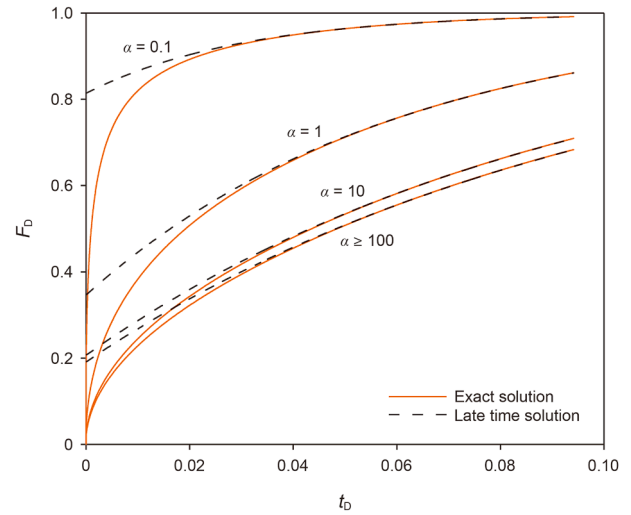


Fig. 3. Comparison of the late-time solution and exact solution for F_D .

$$\ln(p_c - p_e) = s_1 t + b_0 \quad (32)$$

where s_1 is the slope of the straight-line $\ln(p_c - p_e)$ -vs- t plot, and b_0 is the intercept of this straight-line. The following are the expressions for s_1 and b_0 :

$$s_1 = -\frac{4D\lambda_1^2 t}{L^2} \quad (33)$$

$$b_0 = \ln\left(\frac{2\alpha(1+\alpha)(p_0 - p_e)}{1+\alpha+\alpha^2\lambda_1^2}\right) \quad (34)$$

Further discussion is given to Eq. (31) to show this linear relationship. Fig. 4 compares the exact solution with the late-time solution for various volume ratios. The findings show that since t_D is larger than 0.03, the late-time solution and the exact solution are the same. Furthermore, the exact solutions and late-time solutions for various values of α all become nearly identical as the volume ratio α approaches or exceeds 100. As the chamber volume is too large, the pressure decrease in the chamber will be

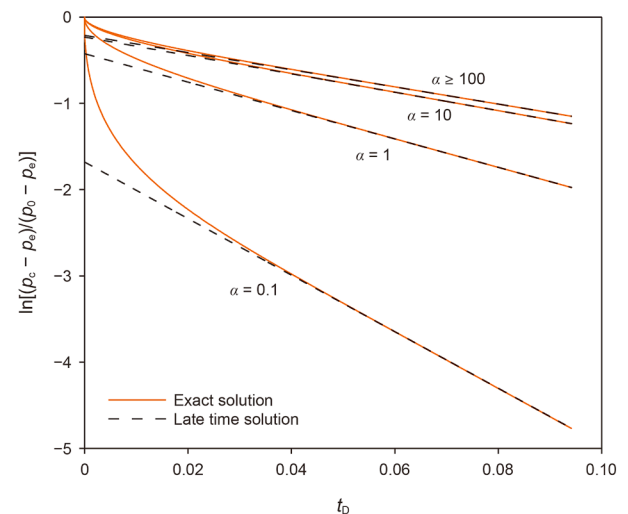


Fig. 4. Comparison of the late-time solution and exact solution for $\ln[(p_c - p_e)/(p_0 - p_e)]$.

extremely small, causing challenges for the pressure transducer to measure the tiny pressure variation.

The linear regression of Eq. (32) can then be used to determine the permeability of the core sample. The slope of Eq. (33) is employed to determine the permeability, as shown below:

$$k_g = -\frac{s_1 L^2 \varphi \mu C_g}{4\lambda_1^2} \quad (35)$$

3.4. Model validation

We generated the numerical results of controlling Eq. (1) using the finite difference method to verify the accuracy of both the exact solution and the late-time solution. Whereas the pressure in the chamber merely depends on time, the pore pressure in the core sample can be split into two dimensions: length and time. Both the length space $[0, L]$ on the x -axis and the time space $[0, t]$ on the t -axis are respectively divided into equal segments by $i = 0, 1, 2, \dots, n+1$ and $s = 0, 1, 2, \dots, J$. The step increments are Δx and Δt , respectively, on the x - and t -axes. Taking p_i^s as an example, it represents the pore pressure a point at $i\Delta x$ and a time at $s\Delta t$.

Using the implicit finite difference approach, we can discretize Eq. (1) as

$$p_{i-1}^{s+1} - (2+M)p_i^{s+1} + p_{i+1}^{s+1} = -Mp_i^s \quad (36)$$

where the definition of the parameter M is

$$M = \frac{\Delta x^2}{D\Delta t} \quad (37)$$

The following matrices can be used to compute the pore pressure (p_1 – p_n) on each node within the core sample:

$$\begin{bmatrix} -2-M & 1 & & & & \\ 1 & -2-M & 1 & & & \\ & 1 & -2-M & 1 & & \\ & & \dots & \dots & \dots & \\ & & & 1 & -2-M & 1 \\ & & & & 1 & -2-M & 1 \\ & & & & & 1 & -2-M \end{bmatrix} \times \begin{bmatrix} p_1 \\ p_2 \\ p_3 \\ \dots \\ p_{n-2} \\ p_{n-1} \\ p_n \end{bmatrix} = \begin{bmatrix} d_1 \\ d_2 \\ d_3 \\ \dots \\ d_{n-2} \\ d_{n-1} \\ d_n \end{bmatrix} \quad (38)$$

Eq. (11) is substituted into Eq. (36), yielding the d_i as

$$\begin{cases} d_1 = -Mp_1^s - p_c^{s+1} \big|_{i=1} \\ d_i = -Mp_i^s \big|_{2 \leq i \leq n-1} \\ d_n = -Mp_n^s - p_c^{s+1} \big|_{i=n} \end{cases} \quad (39)$$

The pressure distribution (p_i^s) within the core sample can be calculated by solving Eq. (38). The total amount of gas in the initial state and the total amount in the equilibrium state are equal. To determine the gas pressure inside the chamber, the following formula is derived:

$$p_0 V_c + p_1 LA\varphi = p_c^{s+1} V_c + A\varphi \int_0^L p_i^s dx \quad (40)$$

The gas pressure in chamber is rewritten as:

$$p_c^{s+1} = p_0 - \frac{A\varphi \int_0^L p_i^s dx - p_1 LA\varphi}{V_c} \quad (41)$$

The above finite difference equations can be solved in a MATLAB environment. Fig. 5 compares the fractional pressure decline (F_D) between the numerical results and the exact solution. Fig. 6 illustrates the numerical results with the exact solution for $\ln[(p_c - p_e)/(p_0 - p_e)]$. It can be seen that the exact solutions and numerical solutions are closely identical. Thus, the exact solution is considered to be feasible to predict the pressure decay data in the chamber. Eq. (35) can be utilized to precisely calculate a core sample's permeability using the BPD technique.

3.5. Porosity determination

Because of its tiny molecular size and low adsorption, helium is the most commonly used gas for assessing rock porosity (Cui et al., 2009). For unconfined samples, a reference cell and a sample cell are often used in the porosity measuring process (Sun et al., 2016). Because the porosity of tight rocks is dependent on stress, the core

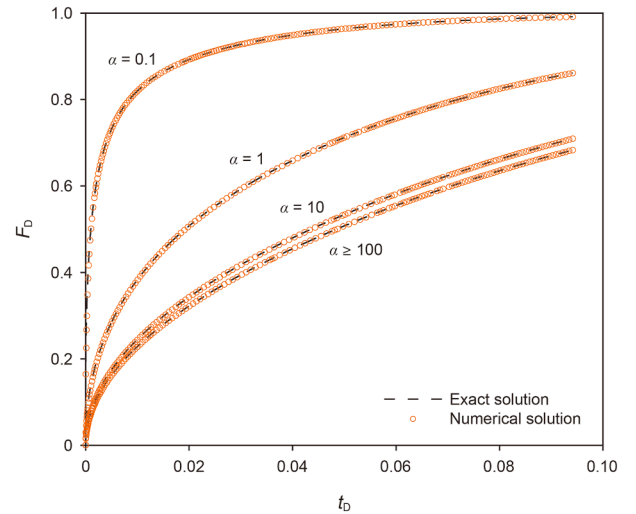


Fig. 5. Comparison of the F_D from exact solutions and numerical results.

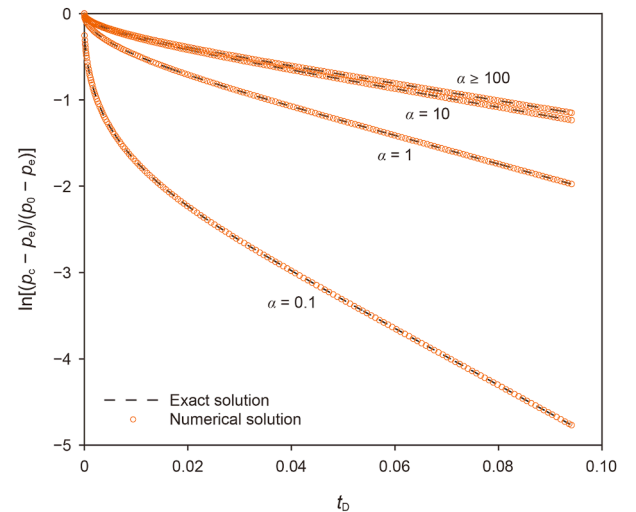


Fig. 6. Comparison of the $\ln[(p_c - p_e)/(p_0 - p_e)]$ from exact solution and numerical results.

sample is often confined in a core holder to obtain the porosity of a sample under in-situ stress conditions (Ma and Zoback, 2017).

Since the core is placed in a core holder, the gas chamber serves as the reference cell for the experimental design, avoiding the necessity for the sample cell. The initial pressure in the chamber and core sample was the same as p_1 prior to the pressure decay process. Following an increase to a value of p_0 , the pressure inside the chamber starts to fall until it reaches an equilibrium pressure of p_e . The total amount of gas at the equilibrium pressure (p_e) equals the total amount of the gas in the chamber under pressure p_0 and the gas in the core sample under pressure p_1 . The gas amount equation can be written as follows:

$$\frac{p_1}{z_1 RT} + \frac{\alpha p_0}{z_0 RT} = (1 + \alpha) \frac{p_e}{z_e RT} \quad (41)$$

where z_1 , z_0 , and z_e are the helium compressibility factors under pressures p_1 , p_0 , and p_e , respectively.

Eq. (41) above can be used to determine the volume ratio α . Substituting α into Eq. (9), the porosity of the core sample is expressed as follows:

$$\varphi = \frac{V_c(z_0 z_1 p_e - z_1 z_e p_0)}{(z_0 z_e p_1 - z_0 z_1 p_e) A L} \quad (42)$$

It should be noted that this BPD method is primarily applicable to intact core plugs without natural or induced fractures. The presence of fractures would alter the gas transport mechanisms and challenge the underlying model assumptions, affecting accuracy.

4. Results and discussion

4.1. Experimental results

Six sets of BPD experiments with confining pressures between 12 and 22 MPa were conducted. Since the mathematical model and its late-time solution assume constant gas properties, the model is strictly validated only when the pressure change during the decay process is sufficiently small. In our experiments, the initial pressure difference between p_0 and p_1 is strictly controlled between 500 and 600 kPa (roughly 6.8%–7.2% of the p_1). This small pressure step is a critical assumption that justifies the use of the late-time solution, as it ensures that the helium viscosity and compressibility remain practically constant throughout the transient decay process. If a large pressure drop were applied, the resulting dynamic variations in gas compressibility would introduce nonlinearities into the governing equations, making the analytical late-time solution invalid and severely distorting the calculated permeability. When measuring permeability for tight cores, high pressure is frequently utilized to reduce the Klinkenberg slippage effect. In this study, the pressure in the gas chamber is set higher than 8.5 MPa, which is higher than the threshold pressure of 7 MPa that gas slippage may occur (Letham and Bustin, 2016; Zhang et al., 2021, 2022).

A high-resolution pressure transducer was used to monitor the gas pressure in the chamber until the pressure in the chamber and core sample were equal. Due to its rapid fall in the early stages compared to the late stages, the pressure was measured at short intervals in the early stages. Fig. 7 displays the pressure decline curves. The pressure was found to decrease quickly at a confining pressure of 12 MPa, and it took around 700 s for the pressure in the chamber and core sample to equalize. Additionally, as the confining pressure rises, so does the experimental time required for the pressure to approach equilibrium. After the confining pressure was increased to 22 MPa, the pressure took around 1400 s

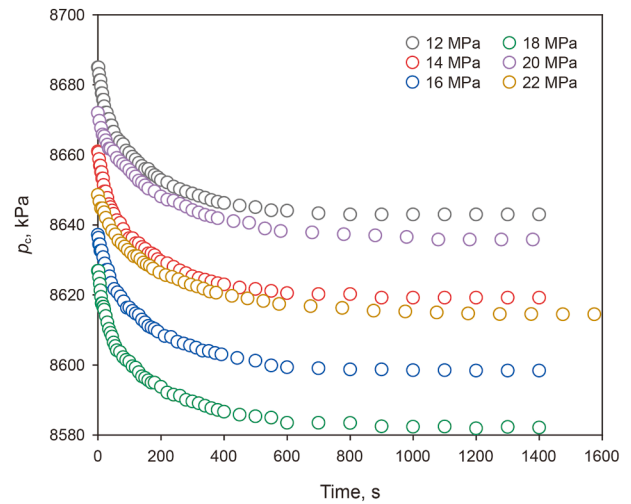


Fig. 7. Helium pressure in chamber obtained from BPD experiments.

to reach an equilibrium state. The decreased permeability could result in a considerable reduction in the gas flow rate. Tight rocks' permeability is extremely sensitive to effective stress, especially in shale rocks (Sun et al., 2020; Zhang et al., 2021).

4.2. Porosity computation

The BPD experiments were used to calculate the porosity. Table 1 shows the initial pressure in the chamber (p_0), the initial pressure in the core (p_1), and the equilibrium pressure (p_e). Another main reason for setting the variations between p_1 and p_0 modestly is to prevent the porosity stress sensitivity effects on the tight core. The pressure in the chamber and core was the same before the pressure decay process. After that, the chamber's pressure was raised by about 7%. These pressure values were obtained, and the helium compressibility factor was calculated. The helium compressibility factor is shown in Fig. 8 for the widely used gas pressure range of 0 to 29 MPa and temperature range of 283.15 K to 313.15 K. Linear interpolation can be used to get the compressibility factor for helium.

As illustrated in Fig. 8, the helium compressibility factor (z) deviates from the ideal gas law ($z = 1$) and increases almost linearly at pressures exceeding 4 MPa. The physical reasoning behind this is that at elevated pressures, the free volume for gas molecules decreases, and intermolecular repulsive forces become dominant (Van Sciver, 2012). Ignoring this physical behavior at high pressures (e.g., setting $z = 1$) would lead to an inaccurate estimation of the actual gas moles in the system, thereby causing significant errors in mass balance and overestimating the calculated porosity. Therefore, incorporating the precise z values into Eq. (42) is essential to eliminate the high-pressure gas deviation effect.

The porosity dropped from 2.61% to 2.23% when the confining pressure increased from 12 MPa to 22 MPa, as shown

Table 1
Porosity and parameters for porosity determination.

C_p , MPa	p_0 , kPa	p_1 , kPa	p_e , kPa	z_0	z_1	z_e	φ
12	8685.0	8096.5	8643.0	1.0419	1.0390	1.0417	0.0261
14	8661.0	8052.0	8619.2	1.0417	1.0388	1.0415	0.0250
16	8637.2	8052.5	8598.4	1.0416	1.0388	1.0414	0.0241
18	8620.9	8020.1	8582.0	1.0415	1.0387	1.0414	0.0235
20	8671.4	8107.5	8635.8	1.0418	1.0391	1.0416	0.0229
22	8648.5	8096.0	8614.5	1.0417	1.0390	1.0415	0.0223

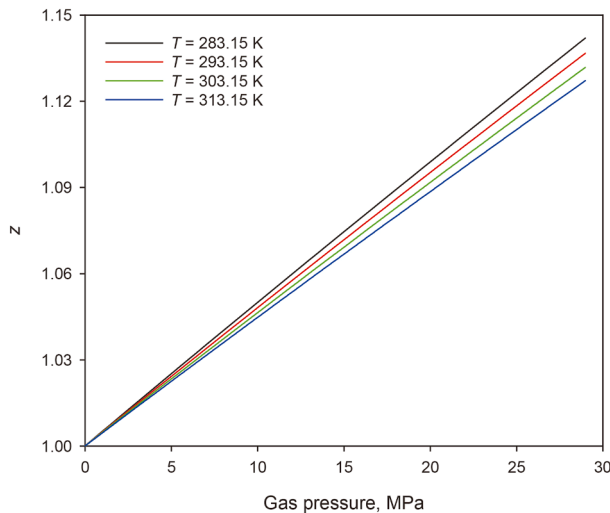


Fig. 8. Helium compressibility factor (z) variation with gas pressure and a temperature of 283.15–313.15 K.

by the data in Table 1. Porosity value is considerably decreased by about 15.0% as a result of the increase in effective stress. It should be noted that the porosity data from crushed samples may not match the data from the core plug because of differences in pore connectivity (Peng and Loucks, 2016; Sun et al., 2016; Zhao et al., 2021). Certain pores cannot be filled with helium because they are not connected. Nevertheless, when the sample is crushed, those pores can be open to helium. Conversely, an increase in stress can cause a reduction in pore size and pore connectivity.

4.3. Permeability computation

Permeability determination can be done with the late-time solution. The slope of the linear relationship between $\ln(p_c - p_e)$ and t should be determined first using the BPD technique, described in Section 3.3. The linear regression and $\ln(p_c - p_e)$ plotted against time are shown in Fig. 9. Eq. (35) can be used to compute the permeability based on this slope. The linear regression based on the late-time solution may contain errors if the early pressure decay data is utilized. As demonstrated in Figs. 3 and 4, as α is close to 15, there would be a linear relationship between $\ln(p_c - p_e)$ and time as the F_D is larger than 0.3. Consequently, it can be assured that the $\ln(p_c - p_e)$ and time exhibit a linear connection by observing the pressure decrease in the chamber over a period of more than 50 s. The linear regression's slope dramatically drops as confining pressure increases, as seen in Fig. 9. The slopes decrease from -5.597×10^{-3} to -3.854×10^{-3} when confining pressures rise from 12 MPa to 22 MPa.

Viscosity, compressibility, and λ_1 are essential variables for the permeability computation. Table 2 displays the parameters required to determine permeability. In Fig. 10(a), the helium viscosity is displayed. In Fig. 10(b), the f_z is displayed. Eq. (3) is used to determine the compressibility of helium by using the f_z data in Fig. 10(b). As the confining pressure increases from 12 MPa to 22 MPa, as Table 2 illustrates, the permeability reduces from 3.715×10^{-16} cm² to 2.209×10^{-16} cm², dropping by approximately 40.5%. The permeability of extremely tight rocks can be effectively determined by this BPD approach. Our BPD method's short experimental duration—less than 450 s—is a big advantage. For tight rocks with comparable permeability, both the traditional and certain modified pressure pulse decay methods have demonstrated substantially longer experimental durations (Liu et al., 2016; Wang et al., 2021b; Yang et al., 2015). This gain in efficiency makes the BPD method a practical and valuable tool for petrophysical characterization.

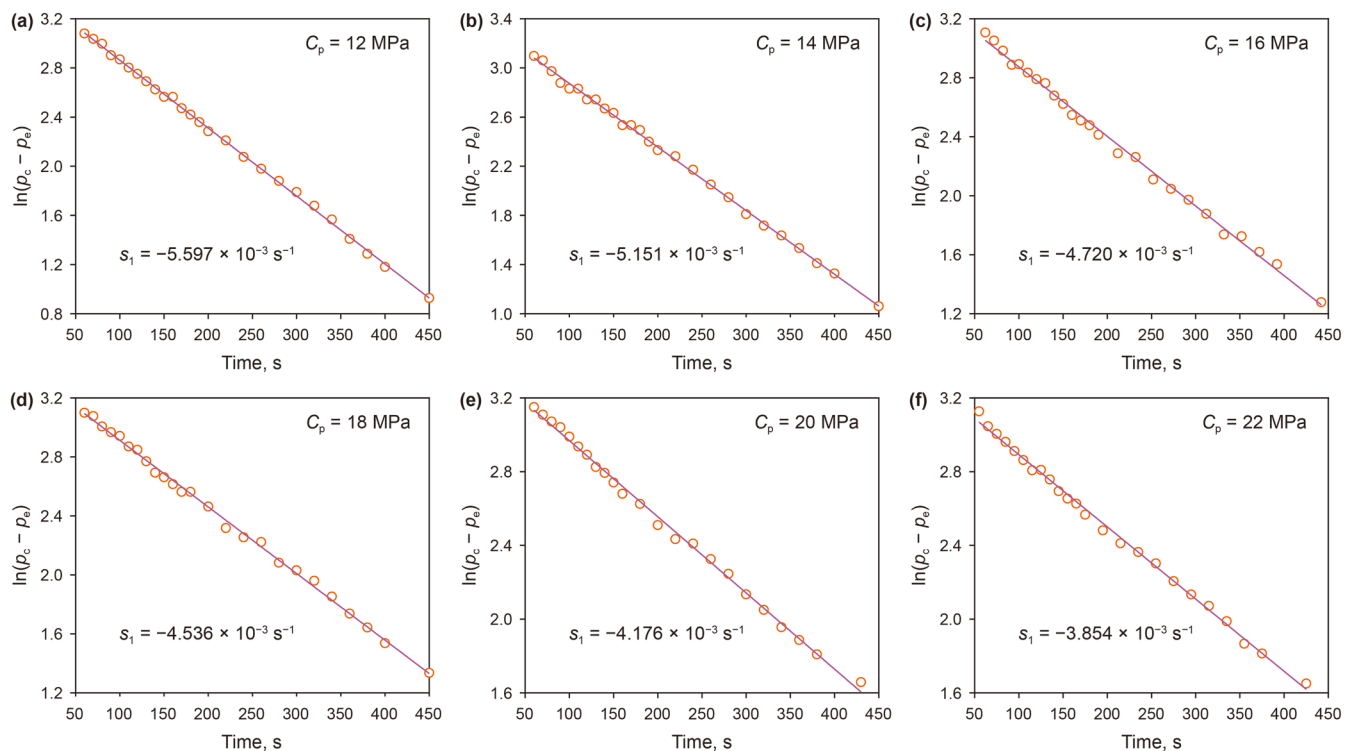


Fig. 9. Plot of $\ln(p_c - p_e)$ against time for BPD experiments.

Table 2
Permeability and parameters for permeability determination.

C_p , MPa	p_{av} , kPa	α	λ_1	μ , 10^{-2} MPa s	c_g , 10^{-4} kPa $^{-1}$	s_1 , 10^{-3} s $^{-1}$	k_g , 10^{-16} cm 2
12	8390.8	13.047	1.618	1.991	1.192	−5.597	3.715
14	8356.5	13.607	1.616	1.991	1.197	−5.151	3.296
16	8344.8	14.114	1.615	1.991	1.198	−4.720	2.919
18	8320.5	14.491	1.614	1.991	1.202	−4.536	2.747
20	8389.5	14.878	1.613	1.991	1.192	−4.176	2.447
22	8372.3	15.288	1.611	1.991	1.194	−3.854	2.209

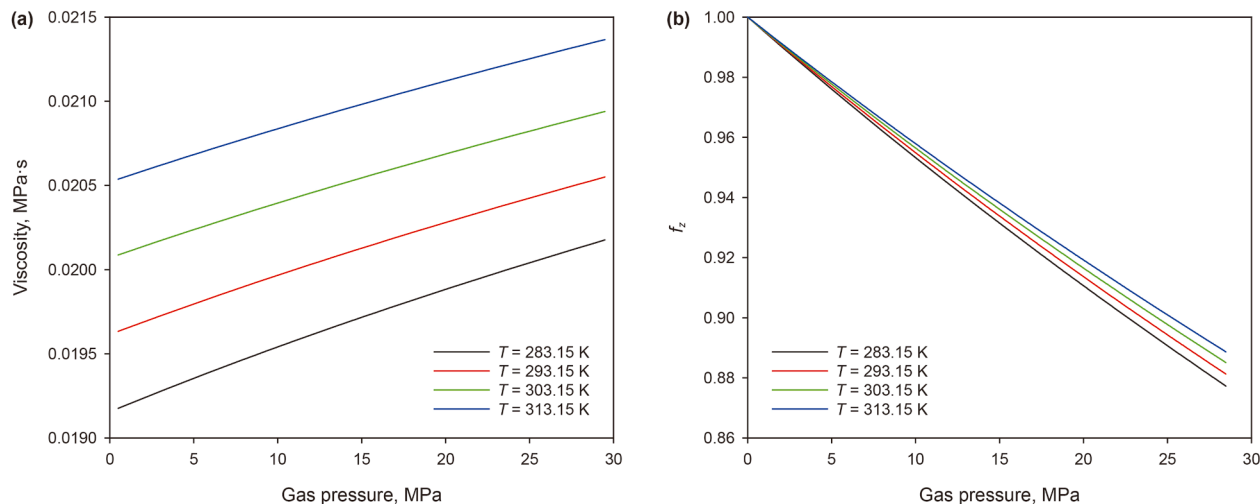


Fig. 10. The viscosity and f_z as a function of pressure with a temperature of 283.15–313.15 K.

4.4. Applicability limits and future work

While the proposed BPD method demonstrates high efficiency and reliability for tight rocks, it is essential to emphasize its current applicability limits. It should be noted that this BPD method is primarily applicable to intact core plugs without natural or induced fractures. As derived in the mathematical model, the exact solution and the late-time linear regression are based on the assumption of one-dimensional gas flow within a homogeneous matrix. The presence of natural or induced fractures would significantly alter the gas transport mechanisms, creating highly conductive pathways that challenge the underlying single-porosity model assumptions and affect measurement accuracy. In fractured samples, the pressure decay profile might exhibit complex dual-porosity behavior, which the current single linear correlation on a semi-logarithmic plot cannot fully capture. To address this limitation, future work could focus on extending the model to account for the effects of fractures and petrophysical heterogeneity. This could be achieved by integrating a dual-continuum mathematical framework into the current BPD analytical solution to separate fracture flow from matrix diffusion. By adapting the theoretical model for fractured samples, this approach can be further improved, thereby broadening its applicability to a wider range of complex reservoir conditions.

5. Conclusions

Precise and efficient measurements of porosity and permeability are essential for the evaluation of tight formations. We designed a bidirectional pressure pulse decay method to assess tight rock porosity and permeability simultaneously. A pressure difference was

established between the two end surfaces of a core sample and a gas chamber. Gas in the chamber can efficiently enter the core sample through its two end surfaces owing to this arrangement. The pressure within the chamber was monitored over time until the system reached an equilibrium pressure. It is straightforward to compute the pore volume using V_c and the pressures (p_1 , p_0 , and p_e). The late-time solution of the mathematical model greatly simplifies the processing of the experimental data. The semi-logarithmic plots of the late-time pressure differential ($p_c - p_e$) and time show a linear relationship. The permeability of tight rocks can be measured more reliably with this method since porosity is simultaneously obtained, minimizing errors from separate measurements. By applying a tiny chamber volume and establishing a bidirectional flow pattern, this approach operates quickly. It is advised that the ratio of chamber volume to pore volume be modest to enable precise monitoring of pressure decay. The porosity and permeability of a tight rock matrix under in-situ stress conditions were measured by applying appropriate confining pressures and pore pressures. The results imply that this BPD technique can be used to assess the permeability and porosity of tight rocks effectively. Future work could focus on extending the model to account for the effects of fractures, thereby broadening its applicability to a wider range of reservoir conditions.

CRediT authorship contribution statement

Xue-Yuan Li: Writing – original draft, Methodology, Investigation, Data curation. **Feng Zhu:** Resources, Project administration, Investigation. **Shao-jie Zhang:** Writing – review & editing, Methodology, Investigation. **Teng-yu Wang:** Investigation, Data curation. **Shang-Bin Chen:** Writing – review & editing, Validation, Supervision, Conceptualization. **Yang Wang:** Writing – review &

editing, Visualization. **Chu Zhang:** Writing – review & editing. **Jin Xu:** Resources, Project administration. **Peng Liu:** Project administration, Data curation.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Acknowledgements

The authors acknowledge the financial support from the National Natural Science Foundation of China (No. 42372159, and No. 42472222), the Fundamental Research Funds for the Central Universities (No. 2025QN1073), the Open Fund of SINOPEC Key Laboratory of Petroleum Accumulation Mechanisms (No. 33550007-22-ZC0613-0042), and the National Science and Technology Major Project (No. 2025ZD1404202).

Nomenclature

A	End surface area of the core sample, cm^2
c	Gas concentration in core, mol/cm^3
c_0	Initial gas concentration in chamber, mol/cm^3
c_1	Initial gas concentration in core, mol/cm^3
c_c	Gas concentration in chamber, mol/cm^3
c_e	Equilibrium gas concentration, mol/cm^3
c_g	Gas compressibility, kPa^{-1}
C_p	Confining pressure, MPa
D	Apparent transport coefficient, cm^2/s
F_D	Fractional pressure decrease
F_{DL}	Late-time solution of fractional pressure decrease
k_g	Permeability, cm^2
L	Length of core, cm
M	$(\Delta x^2/D/\Delta t)$, dimensionless
$\bar{p}$	Laplace transform of pressure, kPa
p	Pressure in core, kPa
p_0	Initial pressure in chamber, kPa
p_1	Initial pressure in core, kPa
p_{av}	Average of p_0 and p_1 , kPa
p_c	Pressure in chamber, kPa
p_c^s	Chamber pressure at a time of $s\Delta t$, kPa
p_e	Equilibrium pressure, kPa
p_i^s	Pore pressure at location of $i\Delta x$ and a time of $s\Delta t$, kPa
s_1	Slope of curve $\ln(p_c - p_e)$ -vs- t , s^{-1}
t	Time, s
t_D	Dimensionless time
T	Temperature, K
V_c	Chamber volume, cm^3
V_p	Pore volume, cm^3
x	Distance from core's left end surface, cm
z	Helium compressibility factor
z_0	Helium compressibility factor at p_0
z_1	Helium compressibility factor at p_1
z_{av}	Helium compressibility factor at p_{av}
z_e	Helium compressibility factor at p_e
α	Ratio of chamber volume to pore volume
Δt	Time step, s
Δx	Grid space on x axial, cm
λ_1	First positive root of $\alpha\lambda_n = -\tan(\lambda_n)$
λ_n	n th positive root of $\alpha\lambda_n = -\tan(\lambda_n)$
μ	Gas viscosity, $\text{MPa}\cdot\text{s}$
φ	Porosity

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