

Article

The Influencing Factors of CO₂ Utilization and Storage Efficiency in Gas Reservoir

Yulong Luo ¹ , Jiazheng Qin ¹, Jianqin Cai ² and Yong Tang ^{1,*}

¹ State Key Laboratory of Oil and Gas Reservoir Geology and Exploitation, Southwest Petroleum University, Chengdu 610500, China

² Dagang Zhaodong Operation Branch, PetroChina Company Limited, Tianjin 300457, China

* Correspondence: tangyong2004@126.com

Abstract: Carbon Capture, Utilization and Storage (CCUS) technology is one of the most practical means to meet zero greenhouse gas emission goal of the Paris Agreement and to ensure profitability, which could achieve permanent sequestration of CO₂. Due to the cost constraints of CCUS implementation, improving recovery and maximizing storage efficiency have become a critical part of ensuring economic efficiency. This research aims to analyze the effects of key factors on enhancing gas recovery and storage efficiency, combined with the validation of CO₂ displacement and storage mechanisms. Therefore, long core experiments and different dimensional simulations were established based on R gas reservoir (one of the actual gas reservoirs in Northeast China), which were designed for sensitivity analyses of different influencing parameters and quantitative analyses of different storage mechanisms during CCUS process. When the conditions (temperature and pressure) were closer to the CO₂ critical point, when the following parameters (the CO₂ purity, the injection rate and the dip angle) became larger, when the reservoir rhythm was reversed and when the irreducible water was in existence, the final displacement and storage effects became better because of weaker diffusion, stronger gravity segregation and slower CO₂ breakthrough. The contributions of different storage mechanisms were quantified: 83.78% CO₂ existed as supercritical fluid; 12.67% CO₂ was dissolved in brine; and 3.85% CO₂ reacted with minerals. Some supercritical and dissolved CO₂ would slowly transform to solid precipitation over time. This work could provide theoretical supports for CCUS technology research and references for CCUS field application. At the same time, countries should further improve CCUS subsidy policies and make concerted efforts to promote the globalization and commercialization of CO₂ transport.

Keywords: CO₂ utilization; CO₂ storage; long-core experiment; numerical simulation; gas recovery



Citation: Luo, Y.; Qin, J.; Cai, J.; Tang, Y. The Influencing Factors of CO₂ Utilization and Storage Efficiency in Gas Reservoir. *Appl. Sci.* **2023**, *13*, 3419. <https://doi.org/10.3390/app13063419>

Academic Editors: Nikolaos Koukoulas and Mickaël Lallart

Received: 15 November 2022

Revised: 1 March 2023

Accepted: 6 March 2023

Published: 8 March 2023



Copyright: © 2023 by the authors. Licensee MDPI, Basel, Switzerland. This article is an open access article distributed under the terms and conditions of the Creative Commons Attribution (CC BY) license (<https://creativecommons.org/licenses/by/4.0/>).

1. Introduction

Since 1980, the global average temperature has risen year by year. By 2020, the global average temperature has been 1.1 °C higher than that at the end of the 19th century. Since the signing of the Paris agreement, countries have declared their greenhouse gas emission reduction policies and committed to achieve carbon neutrality by 2050 or 2060 [1]. The US Congress passed a bipartisan budget bill that expanded the corporate income tax credit for CCUS [2]. Russia proposed a federal law on limiting greenhouse gas emissions in 2021 [3]. The Chinese government has also issued a series of CCUS incentive policies [4]. During The 26th Conference of the Parties (COP26) to the United Nations Framework Convention on Climate Change in 2021, it was announced that the global average temperature will rise at least 1.8 °C by the end of this century, even if countries around the world achieve their emission reduction targets. At the 27th COP, it was suggested that even a 1.8 °C rise in temperature would cause serious impact in vulnerable ecological regions such as Africa [5]. Therefore, countries need to further improve their tax credit policies. At the same time, the establishment of CO₂ global transport chains is also required to break the CO₂ source limitation and promote CO₂ commercialization [6].

As there are still certain controversies and technical barriers in coal, steel and new energy industries, CCUS is currently one of the most effective measures to reduce CO₂ emissions. Carbon Capture, Utilization and Storage (CCUS) is a technology used to mitigate climate change and reduce carbon dioxide emission, which is developed from enhancing oil recovery by CO₂ injection [7,8]. CCUS is still in the development and demonstration stage; there are many prominent problems restricting its development which need to be solved and verified, including high cost and high energy consumption, as well as uncertain safety and reliability of long-term storage [9,10].

Depleted oil and gas reservoirs, unexploitable coal and brine layers are commonly selected for CO₂ storage [11,12]. Among them, the depleted oil and gas reservoirs have the higher adaptation for storage, because of the better economic benefit and safety [13,14]. The storage capacity of CO₂ in depleted gas reservoirs is estimated to reach 8×10^{11} tones, which has great potential [15]. In addition, there are more suitable porosity, permeability and better sealed caprock in depleted gas reservoirs which have advantage over oil reservoir in CO₂ storage [16]. Therefore, the CO₂ storage could be combined with enhancing natural gas recovery, which can effectively ensure profitability and promote energy conservation and emissions reduction. CO₂ storage with enhanced gas recovery (CSEGR) technology has been recognized internationally and has been adopted for field tests in some countries [17,18]. However, CSEGR technology has not achieved large-scale promotion due to the key problems as follows: 90% natural gas can be produced by depletion, due to high compressibility of gas, and there is no need for energy replenishment and secondary recovery in gas reservoirs rather than in oil reservoirs. Therefore, CO₂ injection in gas reservoirs is still in testing phase while widely used in oil reservoirs [19]. CO₂ injected into serious heterogeneous reservoirs will migrate first along high-permeability channels, resulting in premature breakthrough and low recovery efficiency [20,21]. Diffusion and convection occur during CO₂ injection in gas reservoirs, which are generally believed to exacerbate CO₂ breakthrough, pollute the natural gas, increase the cost of gas separation and reduce the recovery and storage efficiency [22,23].

There have been lots of studies on the mechanisms and influencing factors of CCUS. The effects of anisotropy were studied through displacing different directionally cored sandstones with CO₂. The storage capacity enhanced when the normal vector of the dense layer became closer to the gas flow direction [24]. The contributions of different storage mechanisms were quantified through detail 3D reactive transport modeling study on a carbonate-depleted carbonate field. An amount of 79% of CO₂ was trapped by structure storage; 19% was trapped by residual storage; 3% was trapped by solubility storage and no mineral storage after 1000-year storage [25]. The effects of impurity (N₂ and H₂S) were studied by numerical simulation of gas injection in brine formation. As the ratio of impurity increased, the gas migration became wider due to the lower viscosity and solubility of N₂ under reservoir condition [26].

However, there are fewer studies addressing the mechanism and influencing factors of CCUS in gas reservoir. The effects of physical property differences between CO₂ and CH₄ under reservoir condition were studied by core flooding experiments, which could inhibit the fluid mixing and diffusion and achieve more piston-like displacement [27]. The effects of temperature, injection rate and impurities were studied by numerical simulation and long core experiment [28]. As the temperature decreased from 114 °C to 75 °C, the CO₂ storage capacity became higher. The higher the injection rate, the less the enhanced recovery efficiency, but with better economics due to shorter production cycles [29]. As the impurity content increases (N₂), the CO₂ diffusion effect is enhanced, and the difference in physical properties between fluids becomes smaller, potentially causing more natural gas pollution and poorer enhanced recovery efficiency [30]. In the presence of residual water, CO₂ dissolves in water first, thus delaying CO₂ breakthrough, and secondly making the displacing front more stable, thus inhibiting fingering [31]. The stronger the heterogeneity, the more pronounced the CO₂ fingering, and the earlier the breakthrough [32]. There are stronger inhibition effects on CO₂ breakthrough when CO₂ is injected in larger dip

angle formation and in lower spot, because of the gravity segregation caused by density differences [33,34].

So far, there are few field tests and laboratory mechanism studies on CO₂ injection for enhanced recovery and storage in gas reservoirs, especially research focusing on enhanced CH₄ recovery and CO₂ storage at the same time. Based on previous studies, this paper comprehensively analyzed the influence of different parameters on CO₂ displacement and storage process. The long core experiments were conducted for parameters sensitive analysis of injection rate, dip angle, permeability and irreducible water. Then, the simulations were carried out for supplement, which analyzed the effects of temperature, pressure, CO₂ purity and heterogeneity. Finally, the proportion of different storage mechanisms in gas reservoirs were quantified, and the transformation laws between different mechanisms were obtained.

2. Experiments

2.1. Materials

High purity industrial CO₂ (molar concentration greater than 99.9%) and CH₄ (molar concentration greater than 99%) were used in the displacement experiments. The synthetic brine was prepared according to the ion contents and salinity of the R reservoir formation water, as shown in Table 1.

Table 1. Ionic composition of R reservoir formation water.

K ⁺ + Na ⁺	Mg ²⁺	Ca ²⁺	Cl [−]	SO ₃ ^{2−}	HCO ₃ [−]	CO ₃ ^{2−}	Salinity (mg/L)
12,160	27	32	17,305	263	2374	0	32,161

The actual and artificial cores used in the experiments were derived into three groups: relatively high permeability, medium permeability and low permeability. The 1 m long core was usually made of several short cores sequentially due to the limitation of coring technology.

The cores order was calculated by harmonic averaging (Tomas et al.).

$$\frac{L}{\bar{K}} = \frac{L}{K_1} + \frac{L}{K_2} + \cdots + \frac{L_i}{K_i} + \cdots + \frac{L_n}{K_n} = \sum_{i=1}^n \frac{L_i}{K_i} \quad (1)$$

where L is the total length of the cores, cm; $\bar{K}$ is the harmonic average permeability of the cores, $10^{-3} \mu\text{m}^2$; L_i is the length of the i 'th core, cm; K_i is the permeability of the i 'th core, $10^{-3} \mu\text{m}^2$.

Firstly, the harmonic average permeability of the whole long core was calculated and compared with the permeability of each core. The core with the closest permeability was taken out and placed first at the outlet. Then, the harmonic average permeability of remaining cores was calculated and compared with each remaining core. The closest core was taken out and placed in the second place at the outlet. The same work was carried out till every single short core in position (Figure 1).

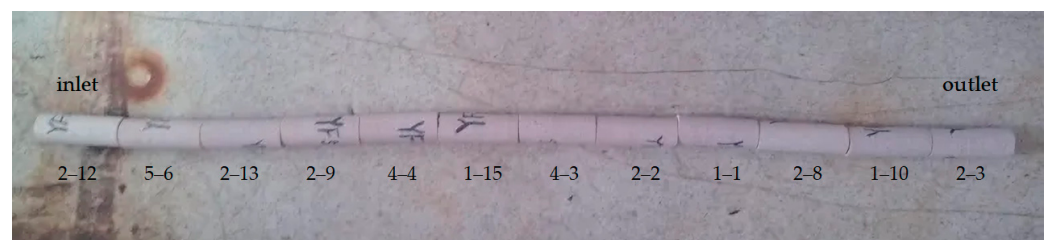


Figure 1. Long core sequence (medium permeability).

The sequences of low, medium and high permeability cores are listed in Tables 2–4, respectively. The cores are sorted from top to bottom as outlet to inlet. To eliminate the terminal effects between cores, short cores were connected by filter papers, loaded into a high temperature, pressure resistant and anti-corrosive rubber sleeve and then contained in a long core holder. The temperature was controlled by multiple groups of heating plates in the convection oven, and the pressure is measured by electronic pressure gauge during the displacement process.

Table 2. Sequence of low permeability long core.

Core Number	Core Length (cm)	Core Diameter (cm)	Pore Volume (cm ³)	Porosity (%)	Permeability (10 ^{−3} μm ²)
20	4.279	2.502	2.248	10.71	1.80
14	4.995	2.502	2.745	11.20	1.80
5	5.128	2.498	2.929	11.64	2.27
27	5.500	2.498	3.138	11.63	2.42
31	5.934	2.512	3.668	12.60	2.49
15	4.400	2.498	2.461	11.40	2.50
78	5.400	2.502	2.567	9.69	1.17
25	5.750	2.502	3.320	11.77	2.53
18	5.051	2.504	3.214	12.97	2.58
77	4.534	2.511	2.209	9.93	0.99
9	5.257	2.502	3.149	12.21	2.60
17	4.971	2.500	3.012	12.35	2.67
22	4.763	2.498	2.979	12.75	2.68
16	5.675	2.512	2.940	10.56	0.93
10	4.846	2.500	2.943	12.38	2.70
8	5.095	2.498	2.910	11.64	2.74
Σ	81.875	2.502	46.432	11.58	2.18

Table 3. Sequence of medium permeability long core.

Core Number	Core Length (cm)	Core Diameter (cm)	Pore Volume (cm ³)	Porosity (%)	Permeability (10 ^{−3} μm ²)
2–12	6.903	2.496	8.305	24.60	9.56
5–6	6.962	2.496	4.266	12.53	7.13
2–13	7.120	2.496	8.740	25.10	11.10
2–9	7.056	2.498	2.689	7.78	6.91
4–4	7.282	2.512	8.729	24.20	11.40
1–15	6.892	2.496	6.842	20.30	6.87
4–3	7.210	2.498	3.055	8.65	11.49
2–2	6.876	2.497	6.866	20.40	6.78
1–1	6.964	2.513	8.562	24.80	11.90
2–8	6.992	2.520	8.505	24.40	13.10
1–10	7.156	2.496	6.684	19.10	6.51
2–3	7.114	2.496	8.872	25.50	13.20
Σ	84.527	2.501	82.115	19.78	9.66

2.2. Experimental Set-Up

The effects of displacement velocity, dip angle, permeability and irreducible water on displacement and storage efficiency were tested by carrying out long core experiments. The CH₄ was displaced by CO₂ with various parameters during the experimental process; the experimental design is shown in Table 5.

Table 4. Sequence of high permeability long core.

Core Number	Core Length (cm)	Core Diameter (cm)	Pore Volume (cm ³)	Porosity (%)	Permeability (10 ^{−3} μm ²)
20	6.400	2.5	4.245	13.52	99.32
14	6.647	2.5	4.471	13.71	96.55
5	6.287	2.5	4.075	13.21	96.49
27	5.739	2.5	3.810	13.53	95.19
31	6.513	2.5	4.461	13.96	103.26
15	4.461	2.5	4.629	21.15	93.14
78	5.845	2.5	4.124	14.38	106.23
25	6.198	2.5	4.437	14.59	110.44
18	6.475	2.5	4.238	12.35	118.75
77	6.854	2.5	4.153	13.54	72.49
9	6.567	2.5	4.362	23.11	129.57
17	4.700	2.5	5.329	12.76	68.44
22	5.981	2.5	3.744	24.99	176.67
Σ	83.442	2.5	61.932	15.581	103.63

Table 5. Experimental design.

Experiment Number	Sensitive Parameter	Parameter Value
1	Displacement velocity	0.1 mL/min velocity, 0° dip angle, medium permeability
2		0.2 mL/min velocity, 0° dip angle, medium permeability
3		0.4 mL/min velocity, 0° dip angle, medium permeability
4		0.8 mL/min velocity, 0° dip angle, medium permeability
5	Dip angle	0.2 mL/min velocity, +45° dip angle, medium permeability
6		0.2 mL/min velocity, −10° dip angle, medium permeability
7		0.2 mL/min velocity, −45° dip angle, medium permeability
8	Permeability	0.2 mL/min velocity, 0° dip angle, low permeability
9		0.2 mL/min velocity, 0° dip angle, high permeability
10	Irreducible water	0.2 mL/min velocity, 0° dip angle, medium permeability, with irreducible water

The long core displacement system (Figure 2) was used for displacement. The whole process of the device is shown in Figure 3, which mainly includes three parts: injection system, hold system and production system. Auxiliary equipment includes constant pressure and velocity displacement pump, gas flowmeter, gas chromatograph, etc. Based on the above equipment, the experimental conditions of a temperature range between 0 and 150 °C and a pressure range between 0 and 70 MPa could be achieved.

**Figure 2.** Core displacement system.

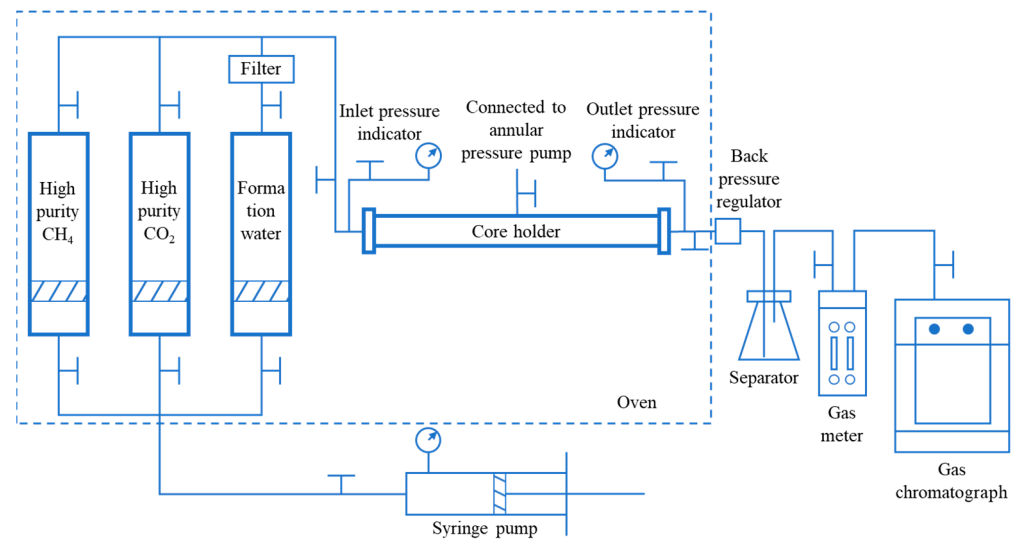


Figure 3. Schematic of the long core displacement process.

2.3. Procedure

The experiments adopted constant velocity displacement method for displacing under the condition of 80 °C and 8 MPa (i.e., the back pressure). The main steps are as follows:

1. The short cores were loaded into the long core holder in sequence and put into the convection oven with a certain dip angle according to the experimental design. Then, the hold system was connected to the injection and production systems;
2. The long cores were displaced with the mixture of petroleum ether and absolute ethanol for cleaning until the outlet fluid has no discolorations and impurities when the confining pressure was improved to 10 MPa, and the speed of displacement pump was set to 5 mL/min with a max pressure of 5 MPa;
3. The long cores were displaced with nitrogen at a constant pressure of 2 MPa for 12 h and vacuumized for 5 h after drying;
4. The long cores were saturated by high purity CH₄ with 8 MPa displacing pressure and 12 MPa confining pressure till the inlet pressure stabilized at 8 MPa. The outlet valve was closed during the saturating process;
5. The CH₄ contained in the cores were displaced by connecting the CO₂ container until the CO₂ content of outlet reached more than 98% or until the recovery rate of CH₄ did not increase. The displacement speed was set as experimental design; the back pressure was set to 8 MPa; and the composition of produced gas was recorded every 0.1 PV. Then, the CH₄ recovery was calculated by analyzing the contents of CH₄ and CO₂ measured through chromatograph;
6. The cores were vacuumized and saturated with CH₄ again to conduct next displacement experiment as the experimental design after this experiment was conducted;
7. Different dip angles represent for “high injection and low production” and “low injection and high production” could be achieved by changing the angle of the long core holder;
8. After the cores were saturated with formation water, the original irreducible water saturation could be established by displacing formation water with CH₄ under the experimental conditions until no water produced.

2.4. Measure Tools and Error Estimation

The measuring tools were a pore permeability instrument, flowmeter of syringe pump, gas flowmeter at outlet, gas chromatograph, annular pressure indicator, inlet pressure indicator and outlet pressure indicator, which would cause systematic errors due to the measurement accuracy. In addition, the fluid retention in pipeline, the air doping in gas

chromatograph and the timing of stopping injection would cause systematic errors (Table 6). The error of recovery could be estimated by

$$\delta_y = \sum_{i=1}^n \frac{\partial y}{\partial x_i} \delta_{x_i} \quad (2)$$

where δ_y is the output error; $\frac{\partial y}{\partial x_i}$ is the sensitivity factor; δ_{x_i} is the input error.

Table 6. Measure tools and systematic error estimations.

Measure Tools and Error Events	Error Value
Pore permeability instrument	Systematic error: $\pm 1\%$
Flowmeter of syringe pump	Systematic error: $\pm 1\%$
Gas flowmeter at outlet	Systematic error: $\pm 1\%$
Gas chromatograph	Systematic error: $\pm 0.5\%$
Annular pressure indicator	Systematic error: $\pm 0.08\%$
Inlet pressure indicator	Systematic error: $\pm 0.08\%$
Outlet pressure indicator	Systematic error: $\pm 0.08\%$
Fluid retention in pipeline	Systematic error: -1.5% max recovery
Air doping in gas chromatograph	Systematic error: $\pm 1\%$
Timing of stopping injection	Systematic error: $\pm 1\%$ for last point

Every single point of the experiments was obtained by three repetitious experimental measurements, so the random errors caused by unpredictable fluctuations (such as environment temperature and earth magnetic field) could be reduced. The confidence intervals (95% confidence level) were calculated by Student's *t* distribution (Equation (3)) [35] due to the repetition time. The 95% confidence interval of CH₄ recovery and CO₂ storage efficiency was $\pm 4.03\%$ (due to largest confidence interval of all experimental points); the 95% confidence interval of CO₂ content was $\pm 2.87\%$ (due to largest confidence interval of all experimental points).

$$\bar{x} - t(C, (n-1)) \frac{\sigma}{\sqrt{n}} \leq \mu \leq \bar{x} + t(C, (n-1)) \frac{\sigma}{\sqrt{n}} \quad (3)$$

where $\bar{x}$ is the mean of the samples; *t* is the distribution boundary value at the confidence level *C*, the degree of freedom (*n* − 1); σ is the standard deviation of the samples; *n* is the repetition time of experimental measurements; μ is the mean of population.

3. Numerical Simulations

3.1. One-Dimensional Simulations for Long Core Displacement

The supercritical features of CO₂ and the difference in physical property between CO₂ and CH₄ were characterized by fluid property analyses which could provide references for factor study of the CO₂ displacement and storage.

Whether the process of CO₂ flooding CH₄ is more inclined to the favorable “piston displacement” could be reflected by the differences in density and viscosity between CO₂ and CH₄, while the degree of supercritical CO₂ deviation from ideal gas could be reflected by compression factor (*Z*), which indicates whether the fluid property is more similar to “gas” or “liquid” under different temperatures and pressures. Therefore, the fluid differences and the appropriate temperature and pressure condition in the displacement process were quantified by calculating the density, viscosity and *Z*-factor values of CO₂ and CH₄ through PR equation.

$$p = \frac{RT}{V-b} - \frac{aa(T)}{V(V+b) + b(V-b)} \quad (4)$$

where R is the gas constant, $8.31 \text{ MPa}\cdot\text{cm}/(\text{mol}\cdot\text{K})$; T is the temperature, K ; P is the pressure, MPa ; V is the gas molar volume, m^3/kmol ; a is the attraction parameter, $\text{kPa}\cdot\text{m}^3/\text{kmol}$; and b is the van der Waals volume, m^3/kmol .

To analyze the influences of reservoir temperature, pressure and injection CO_2 purity on permeation and diffusion during the displacement and storage process, the long core numerical model was established. Then, the displacement and storage process were simulated through CMG/GEM according to the long core experiments. Thus, the recovery and storage efficiency under different temperatures, pressures and injection gas purities were obtained, and the mechanisms and the influence laws were deepened.

The one-dimensional compositional long core model was established along I direction which was based on the experimental long core with medium permeability (Figure 4a). Each grid corresponded to an actual short core according to the long core sequence (Table 3). The accuracy of the numerical model was ensured by using the actual core property parameters for the model grid. Moreover, the heterogeneity was reflected, and the model became closer to the real core by mesh refinement (Figure 4b). Each core (grid) was subdivided into four small grids; the porosities and the permeabilities were calculated by corresponding actual core properties and the actual reservoir variation coefficient. The refined long core model had a better fit to the experimental results (Figure 5), which demonstrated the necessity of considering core heterogeneity.

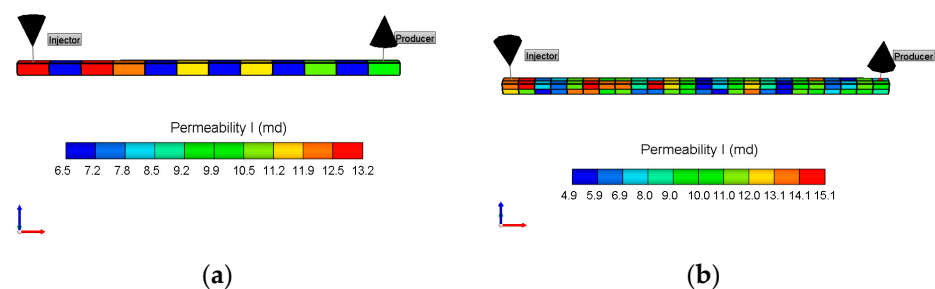


Figure 4. Permeability distribution of numerical long core model. (a) Simple grid; (b) Refined grid.

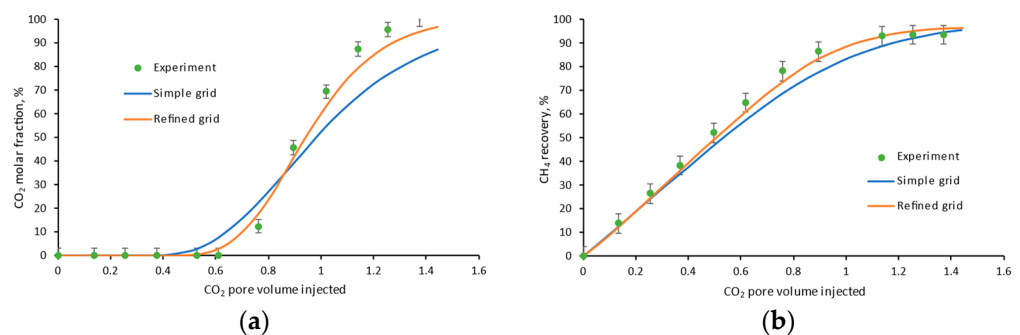


Figure 5. The fitting curves under $0.1 \text{ mL}/\text{min}$ injection rate. (a) CO_2 content at the long core outlet; (b) CH_4 recovery.

The same displacement conditions were adopted in the long core simulations as the experiments. The temperature of basic long core simulation was set to 80°C ; the pressure was set to 8 MPa ; and the injection rate was set to $0.2 \text{ mL}/\text{min}$. Furthermore, simulations (Table 7) of different temperatures, pressures and injected gas purities were designed to obtain the variation in recovery and storage efficiency under different parameters values. Then, the influence laws and mechanisms could be analyzed by the variation in fluid property, recovery and storage efficiency.

3.2. Two-Dimensional Simulations for Heterogeneous Analyses

In order to reflect the vertical heterogeneity of the actual reservoir, the two-dimensional profile numerical model was established to study the influences of layer rhythm on the

recovery and storage effects. Furthermore, the migration laws and gravity differentiation during the CO₂ displacement and storage process could be comprehensively analyzed.

Table 7. Long core simulation design.

Simulation Number	Sensitive Parameter	Simulation Design
1	Temperature	8 MPa, 35 °C
2		8 MPa, 60 °C
3		8 MPa, 80 °C
4	Pressure	7.5 MPa, 80 °C
5		10 MPa, 80 °C
6		15 MPa, 80 °C
7	CO ₂ purity	100%CO ₂
8		90%CO ₂ + 10%N ₂
9		80%CO ₂ + 20%N ₂
10		70%CO ₂ + 30%N ₂

The two-dimensional profile model was cut from the actual gas reservoir model, which was 150 m long in the j direction, 150 m long in the k direction, and divided into 41 grids and 10 layers, respectively. The average reservoir temperature was 40 °C, and the pressure was 10 MPa. The porosity and permeability of the model are shown in Table 8.

Table 8. Basic information of each layer in two-dimensional numerical model.

Layer Number	Thickness (m)	Porosity	Permeability (10 ^{−3} μm ²)
1	15	0.1	20
2	15	0.1	20
3	15	0.15	40
4	15	0.15	40
5	15	0.2	60
6	15	0.2	60
7	15	0.25	80
8	15	0.25	80
9	15	0.3	100
10	15	0.3	100

Two injection wells were set in the model, with 8–10 layers perforated, and one production well was set, with 1–4 layers perforated, to achieve “low injection and high production”. The gas injection simulation was designed with two stages: Stage 1, supercritical CO₂ was injected to improve CH₄ recovery, until the CO₂ content in the produced gas of the production well reached 10%. During Stage 2, the gas injection was stopped, and the injected CO₂ was stored for 100 years. The positive, reverse and compound rhythm of actual reservoir were set by adjusting the porosity and permeability of the model (Figure 6). Therefore, the influence of reservoir heterogeneity on supercritical CO₂ displacement efficiency and storage efficiency could be characterized.

3.3. Three-Dimensional Simulations for Storage Mechanism Analyses

In order to comprehensively analyze the CO₂ storage, distribution and the proportion of CO₂ storage volume with different storage mechanisms in gas reservoir, the three-dimensional numerical well group model was established to completely simulate each stage from depletion to storage, and the CO₂ content under different stages and different forms (supercritical, ionic and mineral state) was obtained.

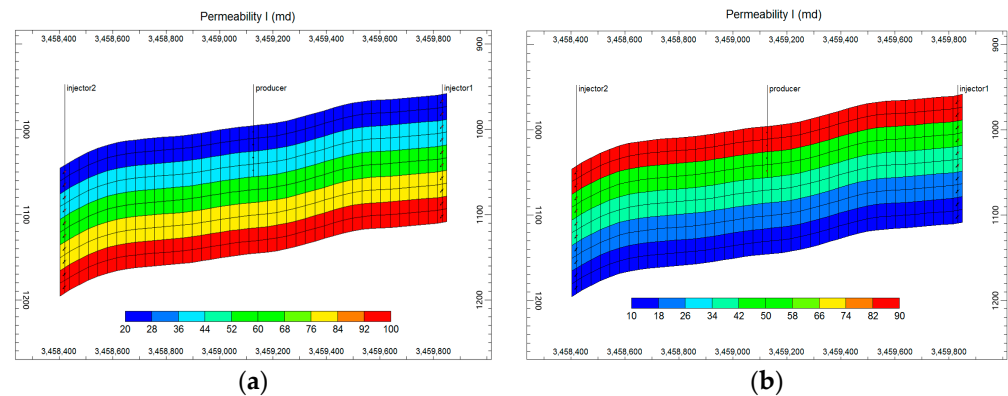


Figure 6. Permeability distribution of numerical model. (a) Positive rhythm; (b) Reverse rhythm.

The numerical well group model was cut from the actual gas reservoir model. The central depth of the model was 1750 m; the formation temperature was 66.8 °C; the initial pressure was 18 MPa; and the water saturation was 45%. The model was established by corner-point grids which amounted to 9000 (30 × 30 × 10), and the areal grid dimension was 50 m × 50 m. Five-point vertical well pattern was adopted, and the well types (production or injection well) were set according to the development phase. The grid setting and well location of the three-dimensional model are shown in Figure 7a.

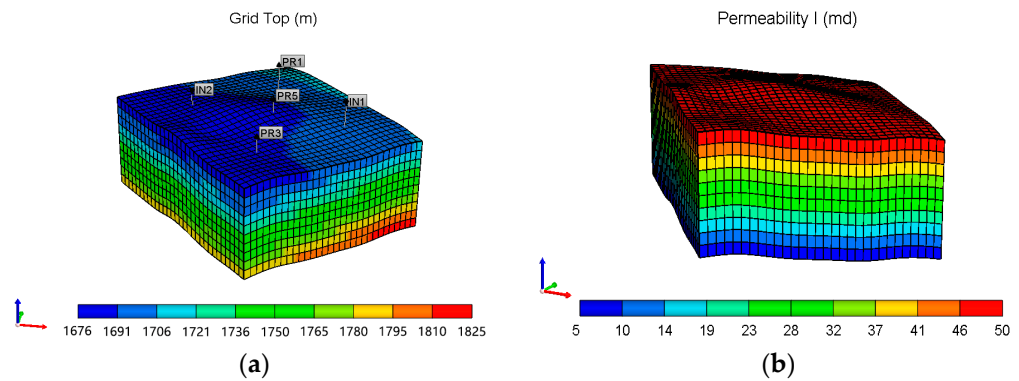
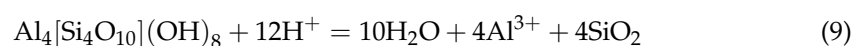
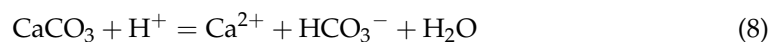
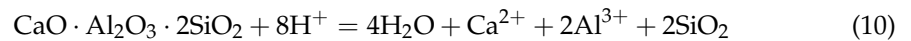


Figure 7. Three-dimensional model. (a) Grid setting and well location; (b) Permeability distribution.

According to the vertical heterogeneity and profile models simulation, the three-dimensional model was designed as a reverse rhythm model which had better porosity and permeability in the upper layers (Figure 7b). The influence of bottom water on supercritical CO₂ displacement and the storage process of the gas reservoir could be characterized by setting the bottom layers as an aquifer.

Supercritical storage, ionic storage and mineral storage were mainly considered in the simulations. Ionic storage: the supercritical CO₂ was dissolved in water and turned into an ionic state (Equations (5)–(7)) when they met in the rock pore during displacement. Mineral storage: the ionic CO₂ (HCO₃[−] ions) reacted with calcite (Equation (8)), kaolinite (Equation (9)) and anorthite (Equation (10)) and turned into solid state (mineral precipitation). The reaction equation of different storage mechanisms were as follows:





The simulation is designed in three phases: the depletion phase, the CO₂ injection phase and the CO₂ storage phase. In the depletion phase, all five wells were set for producing with all gas layers (1–9) perforated. The fluid production is set to $1 \times 10^4 \text{ m}^3/\text{d}$ and with a 3 MPa shut-in pressure for each well. In the CO₂ injection phase, the wells were set for reflecting “low injection and high production” displacement process, according to the displacement results of different dip angle long core experiments. The PR2 and PR4 wells on the east and west sides were changed for injection with only the 8–9 layers and the 10th layer (water layer) perforated; other wells (PR6, PR7 and PR8) kept producing but with only the 1–3 layers perforated. In order to maintain the balance between injection and production, the single well production rate and injection rate were set as $1 \times 10^4 \text{ m}^3/\text{d}$ and $1.5 \times 10^4 \text{ m}^3/\text{d}$, respectively. All the production was shut in as the CO₂ molar content of the produced gas reached 10%. In the CO₂ storage phase, the two injection wells kept working with all layers operated. The injection rate for each well was set to $10 \times 10^4 \text{ m}^3/\text{d}$, and all the wells were shut in when the average reservoir pressure recovered to the original pressure of 18 MPa; then, the 100-year CO₂ storage simulation was carried out.

4. Results

4.1. Fluid Property

The CO₂ Z factor variation curve under different temperatures and pressures was calculated and shown in Figure 8. CO₂ has a smaller Z factor and is more inclined to “liquid behavior”, which has a greater physical difference with CH₄, at the temperature range of 32 °C to 50 °C and pressure range of 7.4 MPa to 20 MPa. The CO₂-CH₄ density and viscosity ratio variation curves under different temperatures and pressures which were shown in Figures 9 and 10, respectively. The differences in density and viscosity between fluids increased when the temperature and pressure became closer to the CO₂ critical point (31 °C, 7.4 MPa). Therefore, the CO₂ could form a supercritical gas cushion by injecting CO₂ to the reservoir bottom, at the temperature range of 32 °C to 50 °C and pressure range of 7.4 MPa to 20 MPa. In addition, the closer that temperature and pressure were to the critical point of CO₂, the less mixture between CO₂ and CH₄ happened in the storage process, and the more inclined to piston-like displacement between “liquid” CO₂ and gaseous CH₄.

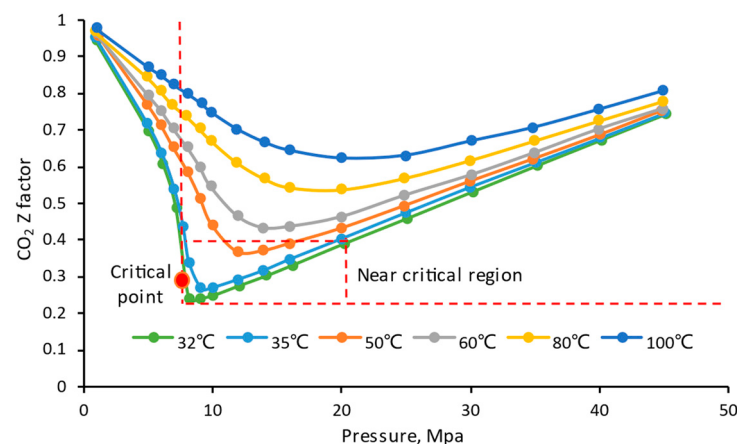


Figure 8. The CO₂ Z factor variation curve under different temperatures and pressures.

4.2. Injection Rate

The variation curves of CO₂ content and CH₄ recovery at the long core outlet under different injection rates were shown in Figure 11. CO₂ breakthrough occurred after 0.7~0.75 PV CO₂ injection in low rate (0.1 mL/min and 0.2 mL/min), while CO₂ breakthrough occurred after 0.77~0.87 PV CO₂ injection in high rate (0.4 mL/min and 0.8 mL/min). The gas breakthrough occurred in high injection rate was 0.1 PV injection later than in low rate, and

the gas recovery in high injection rate was 2.6% higher than in low rate. The experiment shows that there are stronger cumulative influences of CO₂ diffusion on breakthrough due to the longer displacement time under low-rate injection; hence, there is an easier CO₂ breakthrough with a lower recovery.

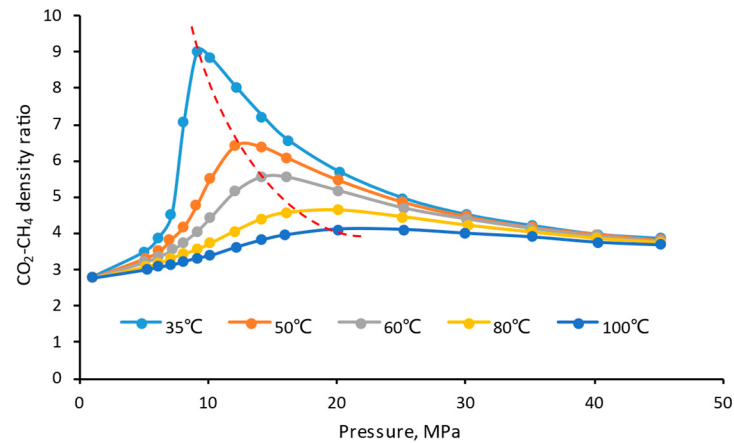


Figure 9. The CO₂-CH₄ density ratio variation curve under different temperatures and pressures.

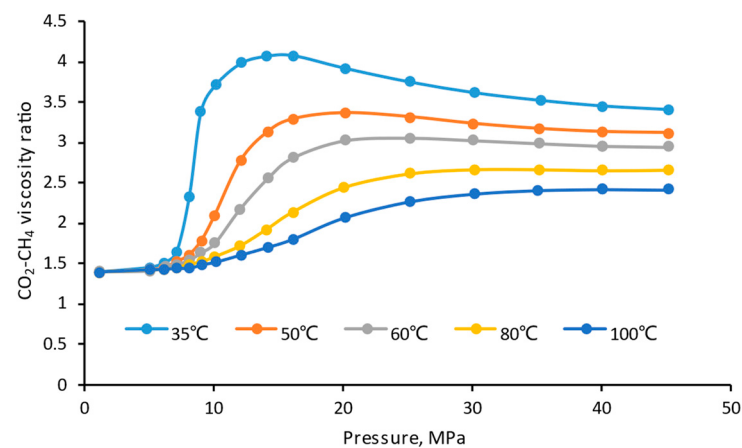


Figure 10. The CO₂-CH₄ viscosity ratio variation curves under different temperatures and pressures.

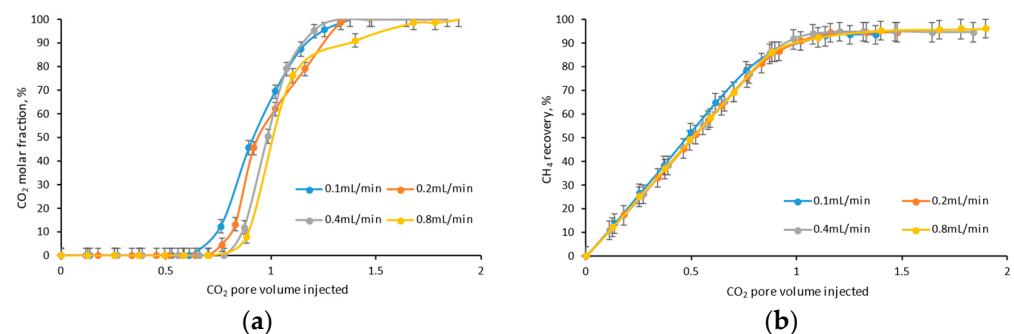


Figure 11. The variation curves under different injection rates. (a) CO₂ content at the long core outlet; (b) CH₄ recovery.

The CO₂ storage effects under different experimental conditions was quantified by CO₂ storage efficiency, the ratio of CO₂ storage volume to pore volume of core. The relation curves between CO₂ storage efficiency and injection volume under different injection rates are shown in Figure 12. The storage efficiency curves increased in fixed slope before CO₂ breakthrough. The growth slowed down more quickly for the relation curve with the smaller injection rate. The analysis indicates that there is a longer mixing time between

CO₂ front and CH₄ under low-rate injection, so there is a wider transition zone and a lower CO₂ storage efficiency after CO₂ breakthrough.

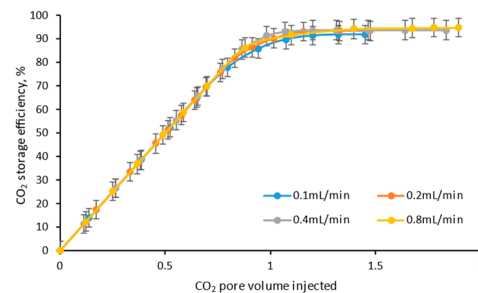


Figure 12. Relation curves between long core CO₂ storage efficiency and injection volume under different injection rates.

4.3. Dip Angle

The variation curves of CO₂ content and CH₄ recovery at the long core outlet under different dip angles were shown in Figure 13. CO₂ breakthrough occurred at 0.7 PV CO₂ injection with a 64.31% recovery at the same time when “high injection and low production” with a 45° dip angle was adopted. CO₂ breakthrough occurred at 0.88 PV CO₂ injection with a 75.91% recovery at the same time when “low injection and high production” with a 45° dip angle was adopted. The experiment shows that the gravity segregation occurs between the dense supercritical CO₂ and the light CH₄. The gravity belongs to the driving force during the “high injection and low production” process, so CO₂ is easier to break through, and there is a wider transition zone and a lower recovery. The gravity belongs to the resistance force during the “low injection and high production” process, which could inhibit CO₂ breakthrough and achieve higher recovery.

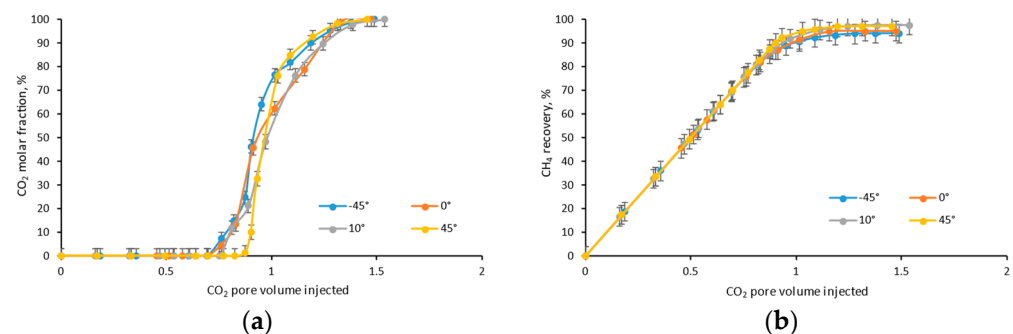


Figure 13. The variation curves under different dip angles. (a) CO₂ content at the long core outlet; (b) CH₄ recovery.

The relation curves between CO₂ storage efficiency and injection volume under different dip angles are shown in Figure 14. The storage efficiency curves increased in fixed slope before CO₂ breakthrough, and the increase gradually slowed down after breakthrough. The ultimate recovery in “high injection and low production” process was lower than other simulations because of earlier CO₂ breakthrough. The analysis indicates that due to the gravity effects, there is a longer transition zone and an earlier CO₂ breakthrough time when CO₂ is injected at the high spot. More CO₂ is produced after an earlier breakthrough, so the storage efficiency is lower. Furthermore, as the injection position becomes lower, the gravity gradually transforms from a driving force to a resistance force. The CO₂ breakthrough is inhibited, and the storage efficiency becomes higher.

4.4. Permeability

The variation curves of CO₂ content and CH₄ recovery at the long core outlet under different permeabilities were shown in Figure 15. The CO₂ injection PV was slightly

larger in the high-permeability core than in the low-permeability core. The experiment shows that there is stronger fingering between CO₂ and CH₄ during displacement in the low-permeability core. Therefore, there is an earlier CO₂ breakthrough time, and a lower ultimate CH₄ recovery efficiency.

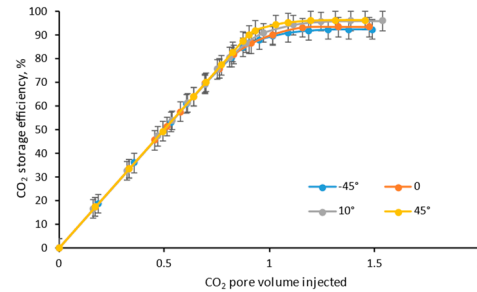


Figure 14. Relation curves between long core CO₂ storage efficiency and injection volume under different dip angles.

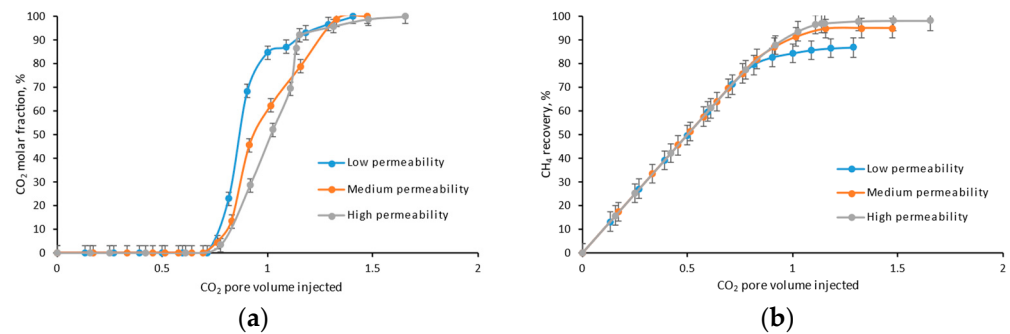


Figure 15. The variation curves under different permeabilities. (a) CO₂ content at the long core outlet; (b) CH₄ recovery.

The relation curves between CO₂ storage efficiency and injection volume under different permeabilities are shown in Figure 16. The storage efficiency curves increased in fixed slope before CO₂ breakthrough, and the increase gradually slowed down after breakthrough. The storage efficiency became higher as the core permeability became larger. It is reflected that there is weaker fingering in high-permeability core, and the displacement between CO₂ and CH₄ is more inclined to piston-like.

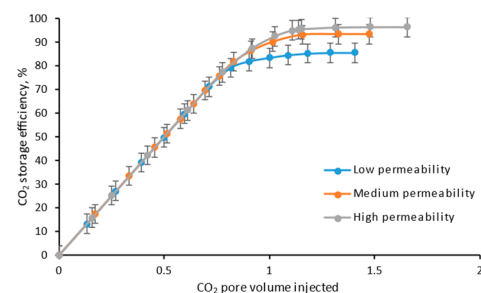


Figure 16. Relation curves between long core CO₂ storage efficiency and injection volume under different permeabilities.

4.5. Irreducible Water

The variation curves of CO₂ content and CH₄ recovery at the long core outlet under different irreducible water conditions were shown in Figure 17. The CO₂ breakthrough in the core with irreducible water was significantly delayed by 0.1 PV compared with the dry core, which had longer a transition zone (due to the longer breakthrough time). It shows that the injected CO₂ will dissolve in water at first, when the irreducible water exists. The displacement begins after irreducible water was basically saturated with dissolved CO₂,

so the CO₂ breakthrough delays. In addition, with the existence of irreducible water, the micropores are filled with water. Therefore, there is less CH₄ trapped in micropores, and the final CH₄ recovery efficiency becomes higher.

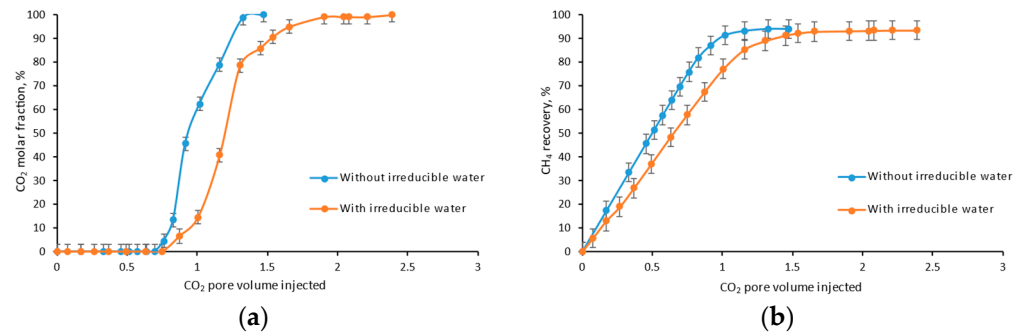


Figure 17. The variation curves under different irreducible water conditions. (a) CO₂ content at the long core outlet; (b) CH₄ recovery.

The relation curves between CO₂ storage efficiency and injection volume under different irreducible water conditions are shown in Figure 18. The storage efficiency curves increased in fixed slope before CO₂ breakthrough, and the increase gradually slowed down after breakthrough. An extra part of CO₂ was dissolved in irreducible water and less CH₄ remained in core pore, but irreducible water also took up an extra part of pore volume. Therefore, the dissolution effect was countered during calculation, which caused the storage efficiency of different irreducible water conditions kept the same.

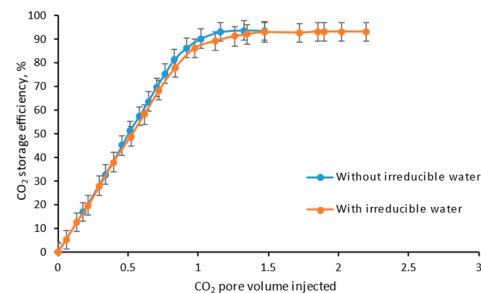


Figure 18. Relation curves between long core CO₂ storage efficiency and injection volume under different irreducible water conditions.

4.6. Temperature

The variation curves of CH₄ recovery and CO₂ storage efficiency under different temperatures were shown in Figure 19. The long core model temperature was set as 35 °C, 60 °C and 80 °C, and the pressure was set as 10 Mpa. Any of the aforementioned conditions would allow the CO₂ to remain in a supercritical state, and as the temperature rose, the supercritical CO₂'s properties gradually changed from "liquid" to "gas" due to the variations in CO₂'s properties at various pressures and temperatures that were calculated in the previous section. The simulations show that the CH₄ recovery increase falls quickly after CO₂ breakthrough. As the temperature increases, the decline rate of CH₄ recovery increasement slows down, and a smoother turning appears in the CH₄ recovery curve, which means that there is a stronger diffusion and a longer transition zone during the displacement. While the temperature decreases, the condition becomes closer to the CO₂ critical point, which increases the difference in properties between CO₂ and CH₄. The CH₄ recovery curve's stronger bend further verifies the lower diffusion in displacement. Therefore, the displacement is more inclined to piston-like which results a higher recovery and storage efficiency.

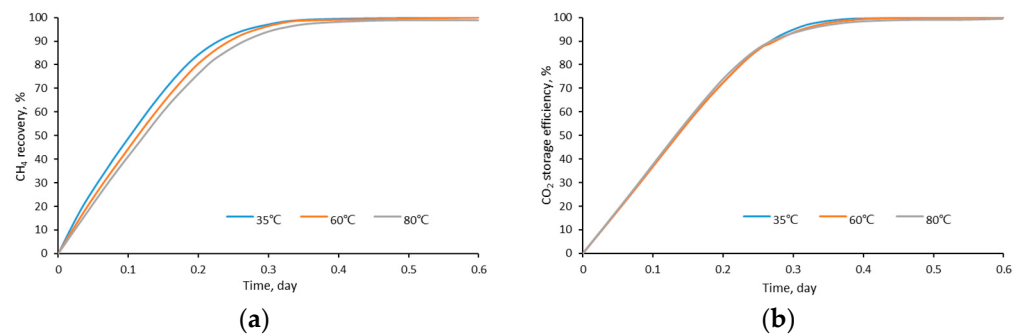


Figure 19. The variation curves under different temperatures. (a) CH₄ recovery; (b) CO₂ storage efficiency.

4.7. Pressure

The variation curves of CH₄ recovery and CO₂ storage efficiency under different pressures were shown in Figure 20. The long core model pressure was set as 7.5 MPa, 10 MPa and 15 MPa, and the temperature was set as 40 °C. In any condition above, the injected CO₂ could maintain a supercritical state. The simulations show that the CH₄ recovery increase falls quickly after CO₂ breakthrough. The difference in properties between CO₂ and CH₄ increases as the condition becomes closer to the CO₂ critical point. Moreover, The CH₄ recovery curve's stronger bend further verifies the lower diffusion in displacement. Therefore, the displacement is more inclined to piston-like which results a higher recovery and storage efficiency.

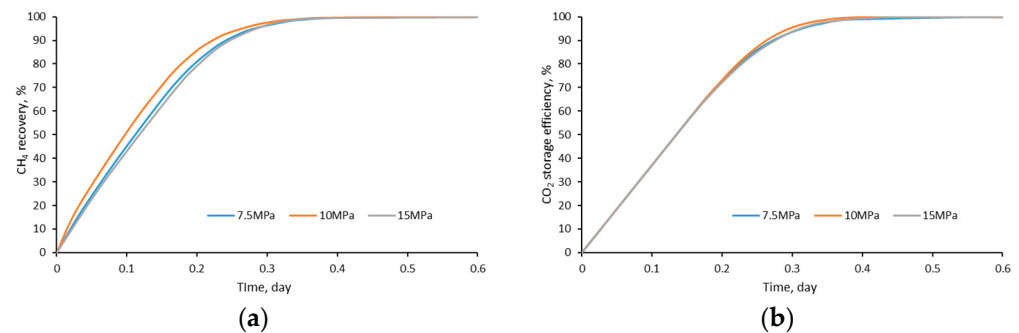


Figure 20. The variation curves under different pressures. (a) CH₄ recovery; (b) CO₂ storage efficiency.

4.8. CO₂ Purity

The CO₂ injection gas is captured and compressed from flue gas due to the high cost of pure CO₂. There are impurities in the injection gas, which would influence the displacement and storage efficiency. Therefore, simulations of different CO₂ purity were set to characterize the influence on displacement and storage efficiency under the same reservoir and displacement conditions. The variation curves of CH₄ recovery and CO₂ storage efficiency under different CO₂ purity were shown in Figure 21. The long core model pressure was set as 10 MPa, and the temperature was set as 40 °C. The simulations show that as the CO₂ purity increases, the CH₄ recovery efficiency is higher when CO₂ breaks through, and the storage efficiency increases significantly according to the CO₂ content of the injection gas. In addition, the differences in storage efficiencies are further enlarged due to the higher compressibility of CO₂ than impurities. While as the impurity contents increase, the gas diffusion and fingering become stronger due to the lower compressibility, viscosity and dissolution of the impurities.

4.9. Heterogeneity

The variation curves of CH₄ recovery and reservoir pressure in the profile model under different reservoir rhythms are shown in Figure 22. The simulations show that the CO₂ breakthrough is earlier in the positive rhythm reservoir while the latest in the

reverse rhythm reservoir. The injected CO_2 will sink to the bottom of the reservoir profile model due to the gravity segregation, and the displacement occurs mainly in the lower part of the reservoir which has a higher permeability in the positive rhythm reservoir, so the CO_2 breakthrough will be exacerbated. The CO_2 breakthrough will be inhibited in the reverse rhythm reservoir due to the lower permeability, and CO_2 flow velocity at lower layers. Therefore, there is a higher CH_4 recovery in the reverse rhythm reservoir. During the storage stage, the reservoir pressure increase is lowest in the reverse rhythm reservoir. Because there is less CH_4 remaining in the reservoir, the weaker CO_2 swelling occurs, which means more stable CO_2 storage.

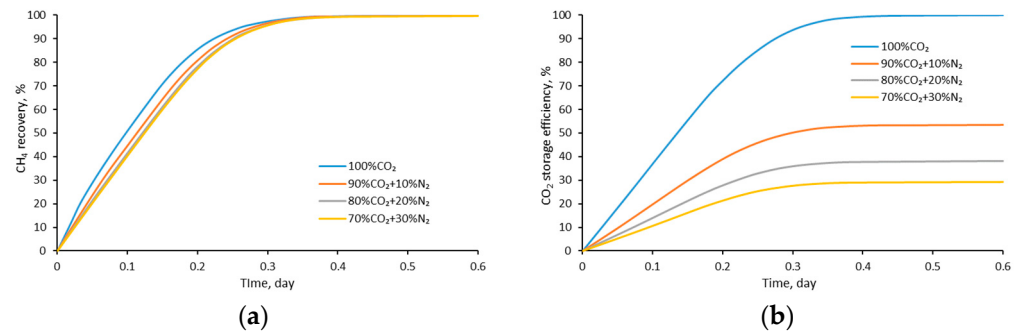


Figure 21. The variation curves under different CO_2 purity. (a) CH_4 recovery; (b) CO_2 storage efficiency.

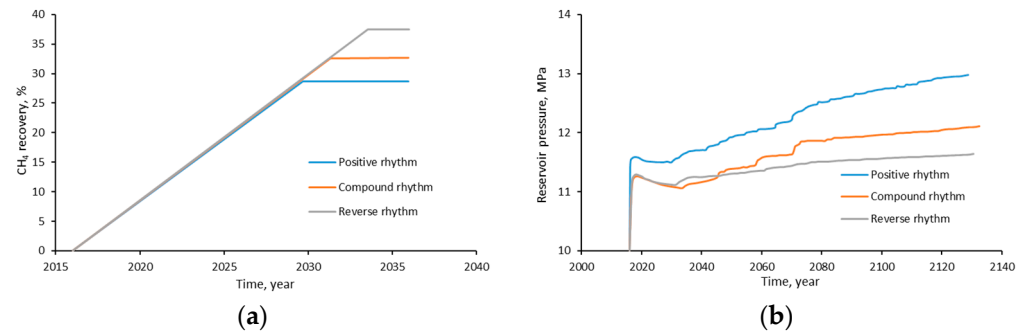


Figure 22. The variation curves under different reservoir rhythms. (a) CH_4 recovery; (b) Reservoir pressure.

4.10. Storage Mechanisms

The variation curves of CO_2 storage amount at the well group model under different storage mechanisms are shown in Figure 23. The variation curves of water ion contents and average reservoir pressure are shown in Figure 23c,d, respectively. The simulations show that the total CO_2 storage amount rises continuously during CO_2 injection after depletion. Among different storage mechanisms, the storage rate is highest in the supercritical storage, followed by the ionic storage, and the mineral stage is the lowest. The supercritical storage amount gradually decreases, while the mineral storage amount increases, and the ionic storage amount remains virtually unchanged. That means the CO_2 stored in supercritical storage gradually transforms to mineral storage during storage stage. The increase in ionic storage amount slows down first among the storage mechanisms, because the irreducible water is basically saturated with dissolved CO_2 . The ion contents increase rapidly during the CO_2 injection stage, while remaining virtually unchanged during storage stage. That means mineral storage is a balanced and slow process. The reservoir pressure decreases continuously in the later storage state. The reservoir energy becomes weaker due to the decrease in supercritical CO_2 .

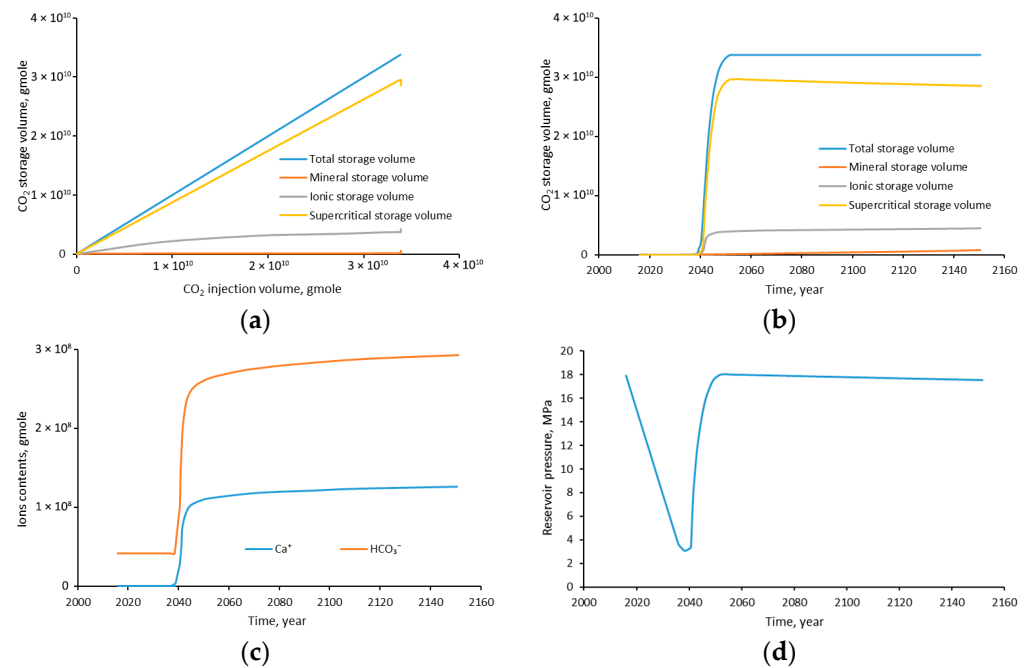


Figure 23. The variation curves of storage analysis. (a) Relation curves between CO₂ storage amount and injection volume under different storage mechanisms; (b) relation curves between CO₂ storage amount and development time under different storage mechanisms; (c) the variation curves of ions contents in irreducible water; (d) the variation curve of average reservoir pressure.

5. Discussions

Due to cost constraints and extraction efficiency, CCUS research in the past has mainly focused on oil reservoirs. With the further strengthening of CCUS subsidy policies and the urgent demand for CO₂ emission reduction, CCUS research on gas reservoirs will gradually return to hot spots. Currently, there are not many studies on CCUS related to gas reservoirs. This study mainly focuses on the effects of factors on recovery and storage efficiency during CO₂ injection in gas reservoirs, which could provide theoretical supports for CCUS technology research and references for CCUS field application. Based on the results and the literature review, the main points are as follows.

This paper adopted a research method combining long core experiments and numerical simulations, which ensured the accuracy of simulation results by refining the simulation grid and fitting with the experiments results. Additionally, the inclusion of numerical simulations simplifies the experimental process and expands the types of sensitive factors.

The effects of fluid property differences, temperature, pressure, permeability, heterogeneity and CO₂ purity on recovery and storage efficiency were investigated, and the influence rules of parameters could be mutually confirmed with previous scholars' research.

As for residual water and injection velocity, there are still different conclusions: some scholars believe that residual water occupies the flow space of pore throats and intensifies CO₂ channeling; some studies also believe that residual water will dissolve CO₂, thereby inhibiting the breakthrough. Some scholars believe that the greater the CO₂ injection rate, the smaller the proportion of CO₂ diffusion, and the better the recovery and storage effects; some studies also believe that with the increase in CO₂ injection rate, both convection and diffusion effects will be strengthened, and the recovery and storage effects become worse. The above differences may be caused by heterogeneity and differences in experimental conditions, which should be further researched systematically in the future.

Meanwhile, the effects of different dip angles on the recovery and storage effect were considered emphatically, and the importance of gravity differentiation in inhibiting CO₂ breakthrough and diffusion was highlighted. It was believed that the larger the dip

angle, the better the recovery and storage effects. The above conclusions are significant for implementing CCUS measures in tilted gas reservoirs.

Based on the complete process of depletion, gas injection and storage, the study analyzed and quantified the influence of different factors on the recovery and storage effects, which is of guiding significance for the actual implementation of CCUS measures to balance the benefits and storage capacity.

6. Conclusions

In this research, the influence of different parameters on CO₂ displacement and storage efficiency during the process of CO₂ injection in depleted gas reservoir was characterized, as well as the storage proportion of different storage mechanisms, through experiments and numerical simulations.

1. In the same injection pore volume, the lower the injection rate, the longer the injection and diffusion duration, the earlier the CO₂ breakthrough, and the lower the ultimate CH₄ recovery efficiency;
2. The lower the core permeability, the earlier the CO₂ breakthrough, and the lower the ultimate CH₄ recovery efficiency, due to the stronger fingering between CO₂ and CH₄;
3. The higher the injection spot (according to the dip angle), the earlier the CO₂ breakthrough, and the lower the ultimate CH₄ recovery efficiency, due to the stronger gravity segregation;
4. As the existence of irreducible water, the ultimate recovery and storage efficiency become higher due to the delay of CO₂ breakthrough caused by dissolution.
5. The density and viscosity ratio of CO₂/CH₄ reach the maximum when the temperature is close to the critical CO₂ temperature (31 °C) and when the pressure is about 11 MPa. Therefore, the closer the reservoir condition to this temperature and pressure, the higher the CO₂ displacement and storage efficiency;
6. The higher purity CO₂ is injected, the more CH₄ is displaced and produced, so there is more space for CO₂ in the reservoir, and higher CO₂ storage efficiency will be achieved. When lower purity CO₂ is injected, the gas diffusion and fingering become stronger due to the lower compressibility, viscosity and dissolution of the impurities;
7. In comparison to the positive and compound rhythm reservoirs, the reverse rhythm reservoir has the greatest storage potential since it has the most recent CO₂ breakthrough, the highest CH₄ recovery efficiency, and the lowest storage stage pressure increase;
8. The CO₂ injection enhances the CH₄ recovery efficiency by 5.8%. Among different storage mechanisms, the CO₂ supercritical storage accounts for 83.78%; the CO₂ ionic storage accounts for 12.67%; and the CO₂ mineral storage accounts for 3.85%. Furthermore, part of supercritical storage will transform to mineral storage over time.
9. The urgent need for CO₂ emission reduction was revealed after COP27. With the continuous advancement of subsidy policies and CO₂ commercialization, CCUS should not be limited to oil reservoirs. Through the above studies, CCUS can also achieve fine recovery and storage effects in tilted gas reservoirs with good geological properties.

In addition to the above conclusions, controversial factors such as residual water and injection rate need to be further investigated, and more influencing factors should be considered at the same time, which could provide more accurate references for implementing CCUS measures in actual gas reservoirs. Meanwhile, in the context of the further improving CCUS subsidy policies and accelerating the commercialization of CO₂ after COP27, further research is needed on adaptable and economic evaluation of CCUS for gas reservoirs.

Author Contributions: Conceptualization, Y.T. and Y.L.; methodology, Y.L. and J.Q.; software, J.Q.; validation, formal analysis, investigation, writing—original draft preparation, Y.L.; resources, data curation, J.C.; writing—review and editing, visualization, J.Q. and J.C.; supervision, project administration, funding acquisition, Y.T. All authors have read and agreed to the published version of the manuscript.

Funding: This research was funded by National Natural Science Foundation of China (51974268), and the Sichuan Province Science and Technology Program (2019YJ0423).

Institutional Review Board Statement: Not applicable.

Informed Consent Statement: Not applicable.

Data Availability Statement: Not applicable.

Acknowledgments: The authors would like to acknowledge Computer Modeling Group Ltd. for providing the CMG software.

Conflicts of Interest: The authors declare no conflict of interest.

References

1. Ferrier, J.R.; Pultar, A.; Maroto-Valer, M. CCUS: Paving the way from COP26 to net zero. *Greenh. Gas Sci. Technol.* **2022**, *12*, 335–338. [\[CrossRef\]](#)
2. Victor, N.; Nichols, C. CCUS deployment under the U.S. 45Q tax credit and adaptation by other North American Governments: MARKAL modeling results. *Comput. Ind. Eng.* **2022**, *169*, 108269. [\[CrossRef\]](#)
3. Bazhenov, S.; Chuboksarov, V.; Maximov, A.; Zhdaneev, O. Technical and economic prospects of CCUS projects in Russia. *Sustain. Mater. Technol.* **2022**, *33*, e00452. [\[CrossRef\]](#)
4. Song, X.; Ge, Z.; Zhang, W.; Wang, Z.; Huang, Y.; Liu, H. Study on multi-subject behavior game of CCUS cooperative alliance. *Energy* **2023**, *262*, 125229. [\[CrossRef\]](#)
5. Lukoye, A.; Gregory, E.E.; Aiah, A.G. COP27 Climate Change Conference: Urgent action needed for Africa and the world. *Pak. J. Med. Sci.* **2022**, *38*, 2058–2060. [\[CrossRef\]](#)
6. Xu, Y.; Zhu, L.; Chang, D.; Tsimplis, M.; Greig, C.; Wright, S. International chains of CO₂ capture, utilization and storage (CCUS) in a carbon-neutral world. *Resour. Conserv. Recycl.* **2021**, *167*, 105433. [\[CrossRef\]](#)
7. Rakhiemah, A.N.; Xu, Y. Economic viability of full-chain CCUS-EOR in Indonesia. *Resour. Conserv. Recycl.* **2022**, *179*, 106069. [\[CrossRef\]](#)
8. Zhang, X.; Li, Y.; Ma, Q.; Liu, L. Development of Carbon Capture, Utilization and Storage Technology in China. *Strateg. Study CAE* **2021**, *33*, 70–80. [\[CrossRef\]](#)
9. Terdal, R.M.; Steeghs, N.; Craig, W. Carbon, Capture, Utilization and Storage CCUS: How to Commercialize a Business with No Revenue. In Proceedings of the Canadian Energy Technology Conference, Calgary, AB, Canada, 16–17 March 2022. [\[CrossRef\]](#)
10. Betiku, A.; Bassey, O.B. Exploring the Barriers to Implementation of Carbon Capture, Utilisation and Storage in Nigeria. In Proceedings of the International Petroleum Technology Conference, Riyadh, Saudi Arabia, 21–23 February 2022. [\[CrossRef\]](#)
11. Derse, O. CO₂ capture, utilization, and storage (CCUS) storage site selection using DEMATEL-based Grey Relational Analysis and evaluation of carbon emissions with the ARIMA method. *Environ. Sci. Pollut. Res. Int.* **2022**, *30*, 14353–14364. [\[CrossRef\]](#)
12. Magzymov, D.; Dindoruk, B.; Johns, R.T. Carbon Capture, Utilization, and Storage in the Context of Petroleum Industry: A State-of-the-art Review. In Proceedings of the SPE Improved Oil Recovery Conference, Virtual, 25–29 April 2022.
13. Wendt, A.; Sheriff, A.; Shih, C.Y.; Vikara, D.; Grant, T. A multi-criteria CCUS screening evaluation of the Gulf of Mexico, USA. *Int. J. Greenh. Gas Control* **2022**, *118*, 103688. [\[CrossRef\]](#)
14. Guo, H.; Liu, X.; Meng, E.; Xu, Y.; Zhang, M.; Fu, H.; Zhang, Y.; Song, K. CCUS in China: Challenges and Opportunities. In Proceedings of the SPE Improved Oil Recovery Conference, Virtual, 25–29 April 2022. [\[CrossRef\]](#)
15. Oldenburg, C.M.; Stevens, S.H.; Benson, S.M. Economic feasibility of carbon sequestration with enhanced gas recovery (CSEGR). *Energy* **2004**, *29*, 1413–1422. [\[CrossRef\]](#)
16. Guo, P.; Xu, Q.; Sun, Z.; Du, J.; Wang, Z. Research progress of CO₂ flooding and geological storage in gas reservoirs. *Lithol. Reserv.* **2016**, *28*, 6–11.
17. Zangeneh, H.; Jamshidi, S.; Soltanieh, M. Coupled optimization of enhanced gas recovery and carbon dioxide sequestration in natural gas reservoirs: Case study in a real gas field in the south of Iran. *Int. J. Greenh. Gas Control* **2013**, *17*, 515–522. [\[CrossRef\]](#)
18. Marbun, B.T.H.; Zulkhifly, S.; Lie, H.S.; Promediaz, A. Northwest Java and East Natuna Field: Perspective to Apply Carbon Capture And Storage (CCS) In Indonesia. In Proceedings of the Carbon Management Technology Conference, Orlando, FL, USA, 7–9 February 2012. [\[CrossRef\]](#)
19. Andersen, P.Ø.; Brattekkås, B.; Zhou, Y.; Nadeau, P.; Nermoen, A.; Yu, Z.; Fjelde, I.; Oelkers, E.H. Carbon capture utilization and storage (CCUS) in tight gas and oil reservoirs. *J. Nat. Gas Sci. Eng.* **2020**, *81*, 103458. [\[CrossRef\]](#)
20. Sun, Y.; Cui, F.; Sun, L.; Du, Z.; Tang, Y. Influence of gravity differentiation and heterogeneity on CO₂ sequestration in gas reservoirs: A case of the XC Gas Reservoir in South China. *Nat. Gas Ind.* **2014**, *34*, 82–86.
21. Liu, J.; Xie, L.; He, B.; Gan, Q.; Zhao, P. Influence of anisotropic and heterogeneous permeability coupled with in-situ stress on CO₂ sequestration with simultaneous enhanced gas recovery in shale: Quantitative modeling and case study. *Int. J. Greenh. Gas Control* **2021**, *104*, 103208. [\[CrossRef\]](#)

22. Liu, S.; Lv, J.; Li, G.; Song, Y.; Zhang, Y. Visualized and Quantitative Investigation of CO₂-CH₄ Diffusion Using X-ray Computed Tomography. In Proceedings of the 14th Greenhouse Gas Control Technologies Conference Melbourne, Cheltenham, UK, 21–26 October 2018.
23. Sun, H.; Yao, J.; Gao, S.; Fan, D.; Wang, C.; Sun, Z. Numerical study of CO₂ enhanced natural gas recovery and sequestration in shale gas reservoirs. *Int. J. Greenh. Gas Control* **2013**, *19*, 406–419. [[CrossRef](#)]
24. Jun, Y.; Yeon, J.; Tae, S. Effects of Anisotropy and CO₂ Wettability on CO₂ Storage Capacity in Sandstone. *Geofluids* **2022**, *2022*, 5900255. [[CrossRef](#)]
25. Amin, S.M.; Tiwari, R.D.; Widyanita, A.; Chidambaram, P.; Ali, S.S.M.; Mazeli, A.H.; Tan, C.P.; Hamid, M.K.A. Impact of karstification in trapping mechanisms of CO₂ storage. *J. Pet. Explor Prod. Technol.* **2022**, *12*, 2817–2831. [[CrossRef](#)]
26. Li, D.; Zhang, H.; Li, Y.; Xu, W.; Jiang, X. Effects of N₂ and H₂S binary impurities on CO₂ geological storage in stratified formation—A sensitivity study. *Appl. Energy* **2018**, *229*, 482–492. [[CrossRef](#)]
27. Al-Abri, A.S.; Sidiq, H.; Amin, R. Mobility ratio, relative permeability and sweep efficiency of supercritical CO₂ and methane injection to enhance natural gas and condensate recovery: Coreflooding experimentation. *J. Nat. Gas Sci. Eng.* **2012**, *9*, 166–171. [[CrossRef](#)]
28. Liu, S.; Ren, B.; Li, H.; Yang, Y.; Wang, Z.; Wang, B.; Xu, J.; Agarwal, R. CO₂ storage with enhanced gas recovery (CSEGR): A review of experimental and numerical studies. *Pet. Sci.* **2021**, *19*, 594–607. [[CrossRef](#)]
29. Cao, C.; Hou, Z.; Li, Z.; Pu, X.; Liao, J.; Wang, G. Numerical modeling for CO₂ storage with impurities associated with enhanced gas recovery in depleted gas reservoirs. *J. Nat. Gas Sci. Eng.* **2022**, *102*, 104554. [[CrossRef](#)]
30. Liu, S.; Yuan, L.; Liu, W.; Zhao, C.; Zhang, Y.; Song, Y. Study on the influence of various factors on dispersion during enhance natural gas recovery with CO₂ sequestration in depleted gas reservoir. *J. Nat. Gas Sci. Eng.* **2022**, *103*, 104644. [[CrossRef](#)]
31. Ding, J.; Yan, C.; He, Y.; Wang, C. Supercritical CO₂ sequestration and enhanced gas recovery in tight gas reservoirs: Feasibility and factors that influence efficiency. *Int. J. Greenh. Gas Control* **2021**, *105*, 103234. [[CrossRef](#)]
32. Honari, A.; Bijeljic, B.; Johns, M.L.; May, E.F. Enhanced gas recovery with CO₂ sequestration: The effect of medium heterogeneity on the dispersion of supercritical CO₂-CH₄. *Int. J. Greenh. Gas Control* **2015**, *39*, 39–50. [[CrossRef](#)]
33. Jia, Y.; Shi, Y.; Yan, J. The Feasibility Appraisal for CO₂ Enhanced Gas Recovery of Tight Gas Reservoir: Case Analysis and Economic Evaluation. In Proceedings of the International Petroleum Technology Conference, Virtual, 23 March–1 April 2021. [[CrossRef](#)]
34. Guo, P.; Li, X.; Sun, Z.; Wang, S.; Du, J. The Numerical Simulation of CO₂ Displacement and Storage in Low-permeability Gas Reservoir. *Sci. Technol. Eng.* **2019**, *19*, 68–76.
35. Gosset, W.S. The probable error of a mean. *Biometrika* **1908**, *6*, 1–25.

Disclaimer/Publisher's Note: The statements, opinions and data contained in all publications are solely those of the individual author(s) and contributor(s) and not of MDPI and/or the editor(s). MDPI and/or the editor(s) disclaim responsibility for any injury to people or property resulting from any ideas, methods, instructions or products referred to in the content.