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Review

Review on CO_2–Brine Interaction in Oil and Gas Reservoirs

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Abstract: Carbon neutrality has become a global common goal. CCUS, as one of the technologies to achieve carbon neutrality, has received widespread attention from academia and industry. After CO_2 enters the formation, under the conditions of formation temperature and pressure, supercritical CO_2, formation water, and rock components interact, which directly affects the oil and gas recovery and carbon sequestration efficiency. In this paper, the recent progress on CO_2 water–rock interaction was reviewed from three aspects, including (i) the investigation methods of CO_2 water–rock interaction; (ii) the variable changes of key minerals, pore structure, and physical properties; and (iii) the nomination of suitable reservoirs for CO_2 geological sequestration. The review obtains the following three understandings: (1) Physical simulation and cross-time scale numerical simulation based on formation temperature and pressure conditions are important research methods for CO_2 water–rock interaction. High-precision mineral-pore in situ comparison and physical property evolution evaluation are important development directions. (2) Sensitive minerals in CO_2 water–rock interaction mainly include dolomite, calcite, anhydrite, feldspar, kaolinite, and chlorite. Due to the differences in simulated formation conditions or geological backgrounds, these minerals generally show the pattern of dissolution or precipitation or dissolution before precipitation. This differential evolution leads to complex changes in pore structure and physical properties. (3) To select the suitable reservoir for sequestration, it is necessary to confirm the sequestration potential of the reservoir and the later sequestration capacity, and then select the appropriate layer and well location to start CO_2 injection. At the same time, these processes can be optimized by CO_2 water–rock interaction research. This review aims to provide scientific guidance and technical support for shale oil recovery and carbon sequestration by introducing the mechanism of CO_2 water–rock interaction, expounding the changes of key minerals, pore structure, and physical properties, and summarizing the sequestration scheme.

Keywords: carbon sequestration; CCUS; CO_2 water–rock interaction

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1. Introduction

In recent years, carbon neutrality has attracted the attention of countries all over the world. Twenty-eight countries around the world have achieved or committed to carbon neutrality targets, including China, which will also strive for peak carbon dioxide emissions by 2030 and carbon neutrality by 2060 [1,2]. Carbon dioxide capture, utilization, and storage (CCUS) is a key area of concern in many carbon neutralization technologies. From 2000 to 2021, a total of 95 countries participated in CCUS research; the number of publications in the CCUS field ranged from 12 articles per year in 2000 to 1084 articles per year in 2021 [3]. From the perspective of the development of thematic research, the issue of sequestration has always been one of the research topics of CCUS.

The types of sequestration are mainly divided into geological sequestration, mineral carbonation, and marine sequestration. Scientific research shows that among the three types

of sequestration, CO_2 geological sequestration technology is one of the best choices for large-scale and low-cost carbon removal of CO_2 in the world [4,5]. As a key mechanism restricting CO_2 geological sequestration, the CO_2 water–rock interaction has become the focus of widespread attention in academia and industry [6]. CO_2 water–rock interaction mainly refers to a series of physical and chemical reactions between CO_2 and formation water, oil, natural gas, and mineral components under formation temperature and pressure conditions during CO_2 flow-through, sequestration, and later diffusion. After CO_2 is injected into the formation, CO_2 first dissolves with formation water to form a weak acid fluid. The acid fluid causes the dissolution of unstable minerals and cements, accompanied by the precipitation of secondary minerals, particles, and precipitation migration to plug the pores, affecting the mineralogical characteristics, pore structure characteristics, physical properties, and other properties of the reservoir, and there is a risk of CO_2 leakage by inducing fractures or reactivating faults. Currently, most of the international research on CO_2 water–rock interaction focuses on the mechanism of the mineral reaction, the change of porosity and physical properties, and the evaluation of reservoir sequestration potential based on CO_2 water–rock interaction, but there is no unified evaluation standard established. This paper introduces the principle, research methods, and cognitions of the CO_2 water–rock interaction, explores the types of reservoirs suitable for carbon sequestration, analyzes the existing problems, and puts forward the suggestion for the next step, to provide scientific guidance for the follow-up study of CO_2 water–rock interaction.

2. Research Method of CO_2 Water–Rock Interaction

Studying the influence of CO_2 water–rock interaction is the basis and premise for the evaluation of the potential for CO_2 sequestration in reservoirs. Observation and research on how CO_2 reacts with minerals in the reservoir and affects the development of pores and physical properties after entering the reservoir has always been a major issue [7]. In terms of the number of studies, about 28,534 results were retrieved in Seeking Knowledge on the topic of CCUS-related technologies from 2003 to April 2024 (Figure 1a). The CO_2 water–rock interaction has widely existed in various industrial activities of CCUS [8]. There are few articles on its comprehensive evaluation. From the keywords of articles related to the CO_2 water–rock interaction, it is found that most articles link CO_2 water–rock interaction with carbon sequestration (Figure 1b). This shows that CO_2 water–rock interaction is an important factor affecting the sequestration effect.

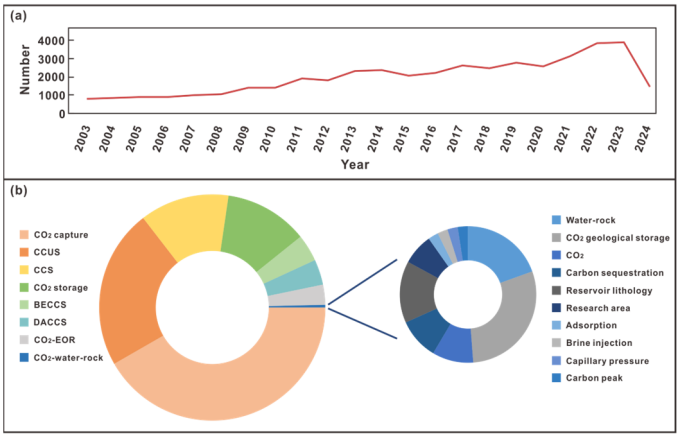


Figure 1. (**a**) Trends in the number of articles on CCUS-related topics from 2003 to 2024; (**b**) b left: the proportion of each topic in the literature published in 2020–2024; b right: the proportion of each keyword in the theme of carbon dioxide water–rock interaction. All data are from Seeking Knowledge (https://www.xunzhi.info/paper/advsearch.py, accessed on 1 August 2024).

Currently, the main research methods are divided into physical simulation methods and numerical simulation methods. The physical simulation generally refers to the tempera-

ture and pressure environment of the formation conditions and designs physical simulation experiments to simulate a series of effects on the reservoir and caprock during the initial CO_2 injection into the formation and the later CO_2 sequestration process. The physical simulation is generally the following two experimental methods: (1) CO_2 water–rock sequestration experiment under formation conditions; (2) CO_2 water–rock flow-through experiment under formation conditions.

2.1. Advances in Physical Simulation Experiments Research Methods

Physical simulation experiment research methods currently have the following situations: (1) Most of the physical simulation experiments will choose to use a gripper in a high-temperature and high-pressure reactor for experiments. For example, Yuan Zhou et al. [9] conducted a flow-through simulation experiment on samples from Changqing Oilfield. The average diameter of the core is 25.24 mm, the average length is 75.44 mm, and the average mass is 72.04 g. Another CO_2 flow-through simulation experiment was performed on samples from the southern Songliao Basin by Zhi Chao et al. [8]. The samples were processed into columnar samples with a diameter of 2.5 cm, and three columnar samples were combined into a 'combined specimen' with a total length of 16.1 cm. However, the use of a gripper will make the selected sample specifications limited to the size of the gripper. The specifications of the experimental samples are not diverse enough, and the resolution of the analysis results is not high-resolution and comprehensive. Although the change of rock samples under the closest formation conditions can be observed intuitively by using the gripper, the changes of sensitive minerals, pore structure, and physical properties in the samples cannot be observed. To improve this, one can choose to improve the gripper, use more diverse specifications of the sample, or use a variety of specifications of the sample, to observe the micro-level changes of the sample. (2) In fact, some scholars have carried out experiments on combined samples before this. Guijie Sang [10] prepared the samples into three forms: powder samples for XRD analysis (300 mesh), four flakes for SANS experiments (thickness: 1 mm), and two cores for ultrasonic testing (diameter: 1 inch); Bing Wei [11] used an average core diameter of 25 mm, a length of 8 mm, and granular samples with a grain size of 0.85 mm to 1.18 mm in the sequestration physical simulation experiment. These simulations can compare the analysis before and after the experiment, but these results lack the analysis of the experimental process. There are a few experiments that record the experimental changes at a fixed time point, but the results cannot be completely matched with the pre-experimental analysis results (Table 1). Therefore, the detection points of the simulation experiment need to be increased to record the changes in the experimental process, which can reflect the change more comprehensively. (3) At present, many simulation experiments record the changes in the experimental process. Although there are obvious changes at a fixed time point, few of them can do in situ comparative analysis. In Table 1, only the analysis experiments of Wu [12] and Zhao [13] can take into account both the recording of the experimental process and the in situ comparative analysis.

For the above three cases, the experiments by Wu [12] and Zhao [13] exactly solved these cases. They designed a combination of more specifications of samples for experiments, so that samples of different specifications can be reacted under the same reaction conditions, which can obtain the maximum number of test results and achieve in-situ experiments. Taking Wu [12] as an example, the rock samples were divided into four specifications for experimental analysis. The two specifications of the plunger samples were subjected to nuclear magnetic resonance (NMR) and micro-CT experimental analysis; 1 cm × 1 cm × 1 cm cubes were for SEM, and QEMSCAN analysis and 200 mesh powder samples were for X-diffraction experimental analysis as well as nitrogen adsorption experiments. During the experiment, the formation water solution in the experiment was examined by an ion solution (Figure 2). This experimental method can completely record the changes of the fixed time points in the whole experimental process of the sample, and high-precision in situ comparison of the same mineral and pore before and after the experiment can be carried out, which was not achieved in previous studies (Figure 3). Unlike the previous physical simulation where the

samples could be observed in real time at high temperatures and pressures, the samples were taken out at normal temperature and pressure. The current high-temperature and high-pressure flow-through, sequestration experiments, and seepage experiments have limitations. It is difficult to observe the complete process of dissolution, precipitation, and mineral migration in the CO_2 water–rock interaction, and it is also impossible to effectively predict the change of pore structure and permeability in the reaction process, and some high-resolution techniques are needed to observe these pore-scale changes. In the future study of CO_2 water–rock interaction, laboratory visualization experiments can be deeply combined to provide detailed data for simulation experiments of each process.

Table 1. Advances in laboratory experiments [12–20].

Literature	Experiment Type	Reaction Solution	Sample Specifications	Experimental Time	Analysis Frequency
I.M. Mohamed, 2011 [14]	flow-through simulation experiments	$scCO_2$ + brine + calcite core	calcite cores (pink desert limestone) with a length of 6 in. and a diameter of 1.5 in.	3 periods	before and after the experiment
Choi, 2012 [15]	sequestration physical simulation experiment	three conditions: $scCO_2$–rock; scCO2–H_2O–rock; $scCO_2$–brine–rock	Big size: D: 38 mm, L: 70 mm; Small size: specimens or powder samples	2 weeks	before and after the experiment
Zijing Li, 2015 [16]	sequestration physical simulation experiment	$scCO_2$ + deionized water + sandstone with high calcium content	The sample was sieved after crushing, and the particle size of the powder was between 75 and 150 μm.	400 h	100 h, 250 h, 400 h
Olabode, A.O., 2017 [17]	flow-through simulation experiments	four natural shale samples + $scCO_2$ + brine	the crushed samples are 1 mm to 2 mm in diameter	5 d	before and after the experiment
Xiaotian Liu, 2018 [18]	sequestration physical simulation experiment	$scCO_2$ + brine + sandstone	25 mm diameter, 20 mm height standard core + rock debris	30 d	liquid: 3d, 6d, 12d, 18d, 24d, 30d; other solids: before and after the test
Wu, 2019 [12]	flow-through simulation experiments	laboratory preparation of liquid + $scCO_2$ + sandstone	standard core + two plugs with diameters of 1 cm and 2 mm	854 h	23 analytical tests during the experiment for a total of 24 analytical tests
Yue Zhao, 2022 [13]	sequestration physical simulation experiment	formation water + $scCO_2$ + tight sandstone	cylindrical samples with a 2.5 cm diameter, and a 5 mm diameter	432 h (18 d)	24 h, 72 h, 192 h, 432 h
Ning Li, 2023 [19]	sequestration physical simulation experiment	H_2O + $scCO_2$ + shale	bulk sample with a side length of 1.5 cm and a height of about 1.0 cm	6 d	before and after the experiment
Ying Li, 2023 [20]	flow-through simulation experiments	carbonatite + formation water + $scCO_2$	core columns of 25 mm in diameter and 35–50 mm in length + rock debris	20 d	before and after the experiment

d = days.

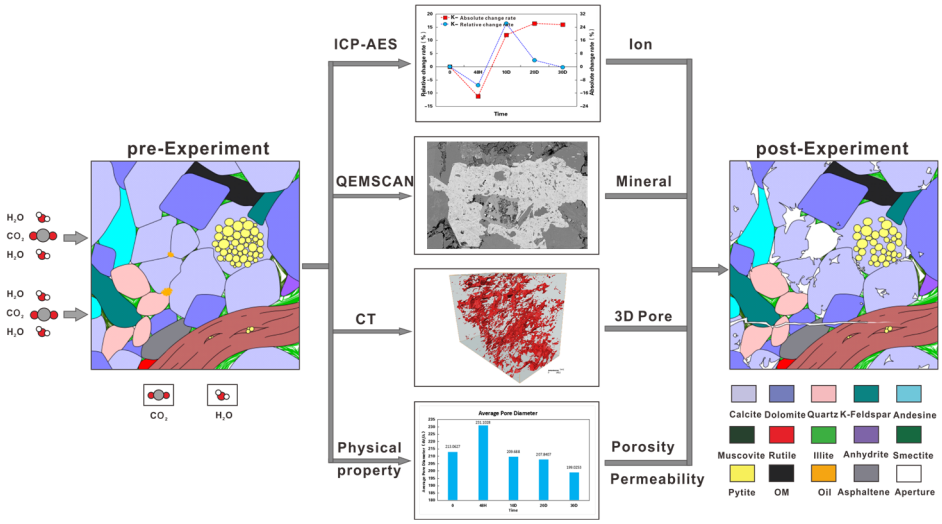


Figure 2. Research process diagram. ICP-AES analysis was performed on the reaction liquid sample, and X-ray diffraction (XRD) experimental analysis, SEM, QEMSCAN, micro-CT, and nuclear magnetic resonance analysis (NMR) were performed on the rock sample. The changes of reservoir before and after the experiment were evaluated comprehensively from the aspects of liquid, mineral, pore structure, and physical properties.

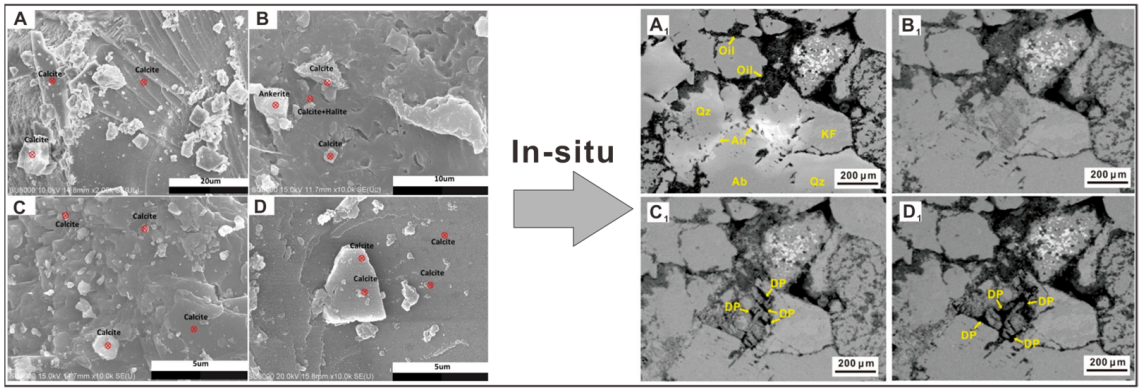


Figure 3. Kaisar Ahmat (2022) recorded the changes of calcite before and after the experiment. (**A**) Case A before the experiment; (**B**) Case A after the experiment; (**C**) Case B before the experiment; (**D**) Case B after the experiment [21]; Zhao (2022) recorded the changes of minerals and pores at the same position during the experiment. ($\mathbf{A_1}$) The initial sample; ($\mathbf{B_1}$) the sample after 24 h, with no observable dissolution; ($\mathbf{C_1}$) holes formed due to dissolution after 72 h; ($\mathbf{D_1}$) after 192 h, the dissolution pores became larger [13].

2.2. Advance in Numerical Simulation Experimental Research Methods

For numerical simulation, there are two ways for different research objectives. The first one is to simulate the experimental results based on the existing physical simulation experiment results, to restore the changes of key minerals, pore structure, and physical properties in the physical simulation process, and to explore whether there are key phenomena in the physical simulation process. At the same time, it also simulates the interaction rate of minerals and the degree of the consequent changes in CO_2 concentration, etc. Senyou An [22] developed a pore-scale volumetric lattice–Boltzmann model coupled with the geochemical simulator, PhreeqcRM. This model was successfully verified with two sets of pore-scale experiments. Such simulation can not only confirm the credibility of the physical simulation experiment, but also restore the details that have not been paid attention to in the physical simulation experiment, confirm the theoretical conjecture, and carry out simulations of other parameters based on the model. However, numerical simulation

can only be applied when the accuracy of the model is high with small relative error [23]. Multi-type models can be established to adapt to the whole process in the future. For different interaction fluids, the simulation of interaction rate and secondary minerals of CO_2 with different minerals under different temperature and pressure conditions can be carried out to improve the accuracy of relevant parameters.

The second one is to simulate medium and long-term data for the results of short-term physical simulation experiments to simulate the effect of medium and long-term sequestration, mainly focusing on the CO_2 charging time and rate, charging mode, as well as the influence of the changes of various parameters on the sequestration efficiency. Gao [24] studied the effect of CO_2 injection on caprocks and reservoirs during geological sequestration, first simulated the CO_2–saline water–rock interaction under real formation conditions, and then modeled the geological sequestration with a process of 500 years by CMG-GEM software. By changing the CO_2 injection time parameters, it is judged whether CO_2 is migratory sequestration, dissolution sequestration, or mineralization sequestration. E. Ghoodjani [25] used the data simulator combined with the analysis model to analyze the sensitivity of the CO_2 injection rate, and to determine the more suitable injection rate for different reservoirs. Accurate medium and long-term simulation can guide CO_2 sequestration and CO_2-EOR strategies to assess the sequestration potential, but it also requires a large amount of data as support.

3. Mineral Evolution

After CO_2 is injected into the ground and in contact with the formation water, some carbon dioxide will dissolve in the water, forming HCO_3^- and CO_3^{2-}, resulting in the formation water being weakly acidic. In an acidic environment, unstable minerals will dissolve and release some Ca^{2+}, Mg^{2+}, etc. Then, it interacts with HCO_3^- and CO_3^{2-} to form stable carbonate minerals. Therefore, there are both dissolution and precipitation phenomena in the progress of the CO_2 water–rock interaction (Figure 4).

$$CO_2(g) + H_2O \rightleftharpoons H_2CO_3(aq), \quad (1)$$

$$H_2CO_3 \rightleftharpoons HCO_3^- + H^+, \quad (2)$$

$$HCO_3^- \rightleftharpoons H^+ + CO_3^{2-}, \quad (3)$$

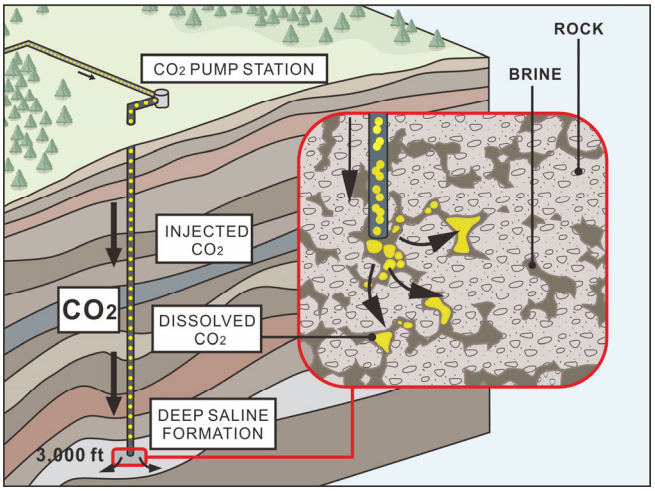


Figure 4. CO_2 water–rock interaction diagram (revising from [26]). The black arrow represents the direction of CO_2 flow.

The CO_2 water–rock interaction characteristics of different minerals are different; some minerals will be dissolved in the acidic solution, while some minerals will be precipitated in the long sequestration process. There are also unstable mineral structures that are eroded

and destroyed, resulting in mineral migration. These factors will affect the porosity and permeability of the reservoir, and these unclear factors are not favorable to the choice of CO_2 sequestration reservoir. However, due to the different experimental schemes, reservoir types, and other conditions, many scholars cannot reach a more unified conclusion.

Minerals can be divided into clay minerals and non-clay minerals. There are three main trends: dissolution, precipitation, and dissolution before precipitation. Among them, non-clay minerals are mainly dolomite, calcite, anhydrite, and feldspar, and clay minerals are mainly kaolinite and chlorite. As carbonate minerals, the changes of dolomite and calcite are particularly obvious in the CO_2 water–rock interaction. Kaisar Ahmat et al. [21] found that when the content of dolomite was more than 85%, it was dissolved under acidic conditions when studying mixed rock samples in the Tarim Basin. When Sebastian Fischer et al. [27] studied the sandstone samples of the Ketzin formation, he found that when the content of potassium feldspar was 5–25%, the samples would precipitate dolomite crystals at the cost of plagioclase dissolution. At this time, the change trend of dolomite was mainly precipitation (Figure 5a). Calcite reaction is more sensitive to temperature and will dominate precipitation at higher temperatures [18] and dissolution at lower temperatures [28]. In addition, there will be samples with high dolomite content. Calcite will be dissolved first, and then a high content of dolomite will be converted into calcite precipitation (Figure 5b). The temperature peak of the maximum solubility of calcite may occur between 135 °C and 185 °C; when the experimental temperature exceeds this temperature, the solubility of calcite will decrease, thus affecting the water–rock interaction of CO_2 and minerals [29]. Gunter et al. [30] also pointed out that aluminosilicates containing calcium and magnesium (or other divalent cations) are the greatest potential minerals to improve the sequestration capacity of CO_2 because they can combine with H^+ to form carbonate minerals, kaolinite, and quartz while dissolving.

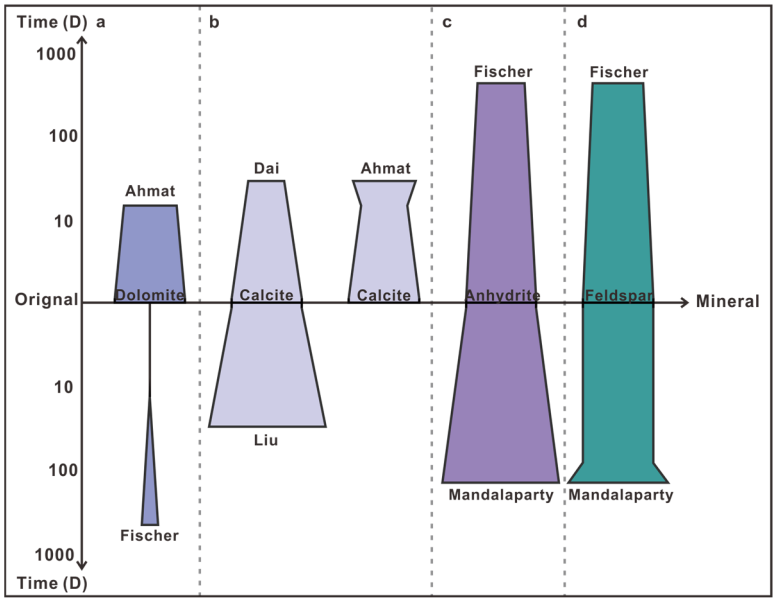


Figure 5. Schematic diagram of trends in four minerals: dolomite, calcite, hard gypsum, and feldspar [18,21,27,28,31]. (**a**) dolomite trends in interaction; (**b**) calcite trends in interaction; (**c**) anhydrite trends in interaction; (**d**) feldspar trends in interaction.

Sebastian Fischer, in his study of sandstone formations in Stuttgart, found that when the initial concentration of calcium and sulfate in synthetic brine was lower than that of formation fluid, anhydrite dissolved to increase the ion concentration in brine [27]. Mandalaparty conducted a study on the reaction of self-made diamictite rock samples with CO_2 + SO_2 and found that anhydrite crystals rapidly nucleate and grow [31] (Figure 5c). In the Stuttgart sandstone formation, to balance the salt water concentration and the

formation concentration, some feldspar will be converted into calcite, and the samples with high feldspar content will be preferentially dissolved, and the surface is accompanied by corrosion texture [27]; in the samples with high content of diamictite rock quartz, quartz will first dissolve to provide ions, while the precipitation speed of feldspar is faster than that of quartz in the later stage of precipitation, and, finally, feldspar is precipitated [31,32] (Figure 5d). Zhang et al.'s experiment using CO_2 hydrolysis solution in the sandstone of the Rio Bonito formation in southern Brazil showed that feldspar and calcite would dissolve, and silicate minerals might also precipitate. Due to the different types of reservoirs, the degree of dissolution was also different [33,34]. It can be seen that the changes in key minerals are different, and the experimental conditions are important influencing factors, but the specific rules still need to be explored.

4. Pore Structure and Physical Property Changes

4.1. Pore Structure

The previous evaluation of pore structure is mainly aimed at the average pore size and fracture, which together affect the change of reservoir physical properties. After CO_2 is injected into the formation, the early dissolution will lead to the increase of dissolution pores, which will expose more mineral surfaces. With the extension of reaction time, the average pore size will gradually increase [28,35–38]; in some samples with high content of carbonate minerals, the average pore size decreases due to the expansion effect and precipitation [39] (Figure 6). Park et al. investigated the effect of CO_2 sequestration on the porosity of caprock in Janggi Basin, South Korea, through physical simulation experiments. After the experiment, they observed that the dissolution of primary minerals led to an increase in caprock porosity. The porosity of the samples before and after the experiment was tested by pressure mercury porosity measurement and CT scanning. Respectively, the porosity increased from 14.9% to 18.7% and from 15.1% to 20.7%, and the dissolution of primary calcite was the cause of the porosity change [40].

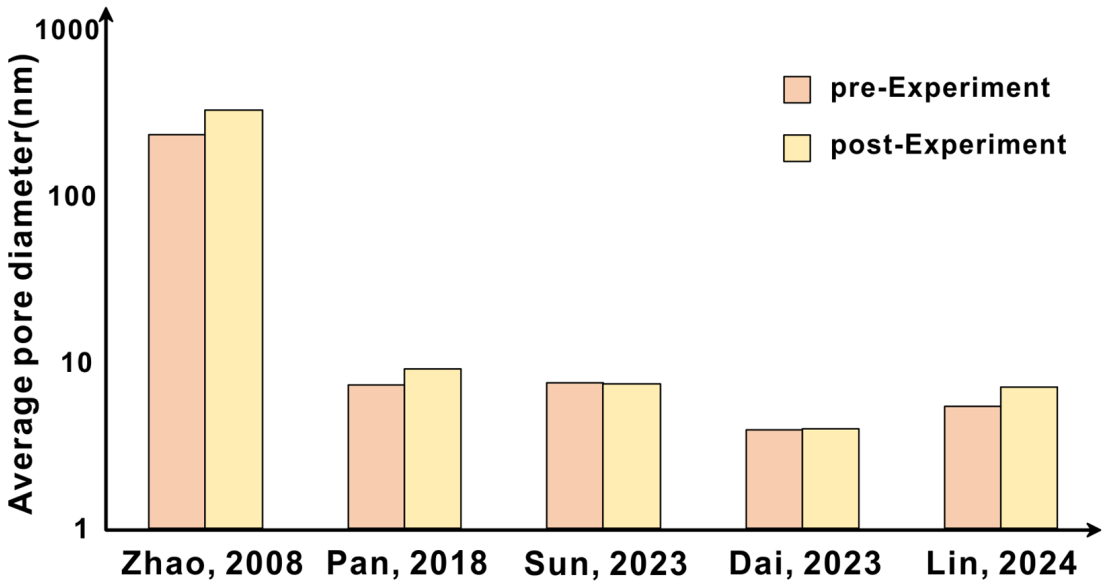


Figure 6. Trend of average pore diameter before and after the experiment [28,35,37–39].

For fractures, after the reaction of SC-CO_2, saline, and samples, the mechanical properties of the samples are reduced, and SC-CO_2 penetrates the pore dissolution minerals, leading to an increase in the number of hydraulic fractures, which expands the instability of fracture and increases the complexity of the fracture shapes [41]; it also reduces the mechanical strength of the sample, promotes the occurrence of fracture, and activates pre-existing random directional microfractures, which increases the volume of main/microfractures [42],

but diagenesis can also hinder fracture growth [43]. These characteristics have an impact on long-term sequestration security.

4.2. Physical Property

The predecessors' cognition of the evolution of physical properties also has varied views with different experimental settings. In the flow-through experiments, the CO_2 injection rate is an important factor. The CO_2 injection rate not only affects the CO_2 water–rock reaction rate, but also promotes mineral migration [12,44] (Figure 7). During the experiment, the migration of fine detached particles caused by upstream dissolution will block the downstream microfractures, and the physical properties decrease [45–47]. If the released particles are washed away, the alteration layer is detached, and the physical properties increase [48,49]; if the released particles are redeposited in the fracture, the pore size of the microfracture is significantly reduced and the physical properties are reduced [50,51]. For example, I. M. Mohamed conducted a flow-through experiment with homogeneous carbonate rocks and found that the permeability of the core is the same along the length of the core. The core is cut into three pieces, regardless of the temperature and injection rate; the first core is increased compared with the original permeability due to calcite dissolution, and the latter two cores begin to show a decreased permeability because of mineral migration. At different injection rates, the overall permeability of the core also changes differently. When the injection rate is 5 cm^3/min, the permeability increases; when the injection rate is 2 cm^3/min, the permeability decreases [14]. However, there are also different opinions. Loquot [52] found that regardless of the injection rate and the type of saline, the permeability increased in the experiment of Heletz. In the sequestration experiment, the change of physical properties is closely related to the temperature and pressure conditions and the type of reservoir. The corrosion of minerals can weaken and expand the edge of dissolved pores and increase the physical properties [42,53] (Figure 7). When the mineral expansion effect is stronger than the dissolution effect, the physical properties decrease [39]. With the increase of experimental pressure, the porosity of the sample increases first and then decreases [54]. Different reaction temperatures lead to different degrees of dissolution and precipitation of different minerals, which in turn affects the physical properties [8,55].

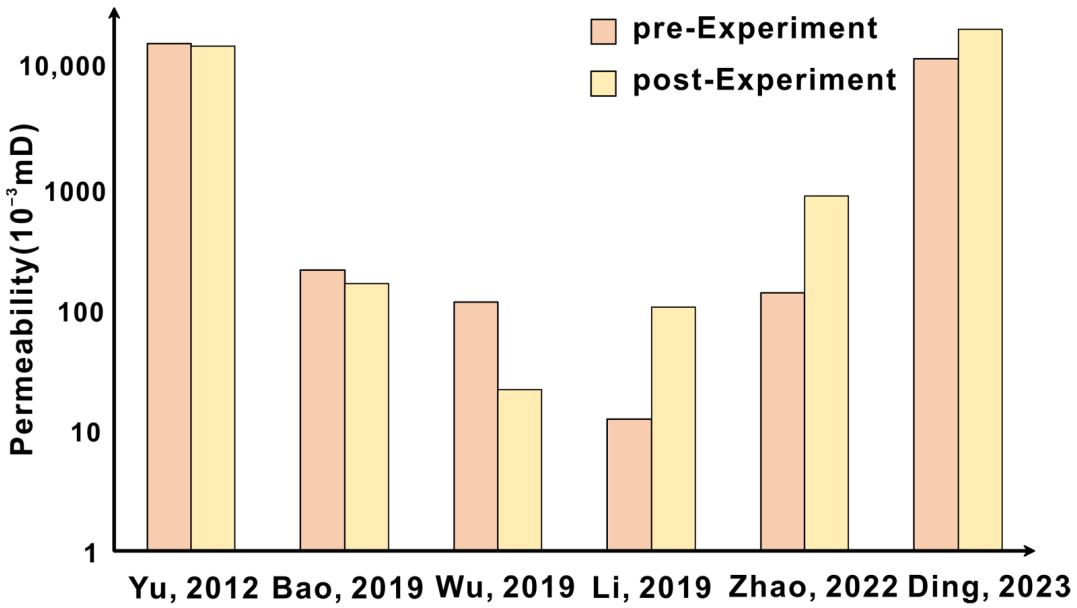


Figure 7. Trend of permeability before and after the experiment [8,12,13,42,44,53].

5. Selection of Geo-Storage Reservoir

Global CCUS technology is in the research and development stage, and due to various cost, environmental, policy, and other issues, most of the CCUS projects in operation are aimed at the single technical aspect of CCUS, and gradually carry out large-scale CCUS demonstration projects. According to incomplete statistics, China has more than 20 CCUS experimental and demonstration projects under construction and operation, 13 international cooperative research projects, and 17 projects supported by the Chinese government [24,56]. Among them, China's separate geological utilization and sequestration projects account for about 10%, which is a significant gap compared with developed countries with experience in multiple full-process CCUS technology demonstration projects [57,58] (Table 2); there is still much potential for China's current carbon sequestration technology and industrial processes.

Table 2. Summary of global CO_2 geo-storage projects [59].

Project/ Country	Estimated Sequestration	Geological Sequestration	Sequestration Formation/Caprock	Injection Depth	Injection Rate	Start-Up Year	Project Details
Rangely/ Northwest Colorado, USA	25 Million tons (Mt)	Deep saline aquifers	Sandstone/garden gulch shale	1950 m	4.5 mm^3/day	1986	CO_2 is injected in alternating slugs with water at a ratio of 1:1. The sequestration thickness is 160 m.
Sleipner project /Norway	25 Mt	Deep saline aquifers	Sandstone/thick shale	800 m	2800 t/day	1996	\
Nagaoka field/Japan	128 Mt	Deep saline aquifers	Sandstone/mudstone	1230 m	20–40 t/ day	2000	CO_2 is injected in alternating slugs with water at a ratio of 1:1. The sequestration thickness is 60 m.
Weyburn field/ Canada	20 Mt (2000–2025)	EOR	Carbonate rock/gypsum-salt layer	1450 m	6300 t/day	2000	CO_2 is injected into low-porosity and low-permeability reservoirs.
Salah project/Algeria	≈17 Mt (2004–2011)	Deep saline aquifers	Sandstone/shale	\	14–15 t/ day	2004	The project ended in 2011 due to the caprock concern, providing insights into the CO_2 injection in low-permeability reservoirs.
Jilin Oil Field/China	about 1.18 Mt of CO_2	EOR	Sandstone/mudstone	\	250,000 t /year	2008	The CO_2 injection in low-permeability reservoirs.
Ordos project/China	approximately 0.15 Mt of CO_2 in 2014	Deep saline aquifers	Sandstone/shale and mudstone	\	100,000 t /year	2010	CO_2 is injected into low-porosity and low-permeability reservoirs.
Gorgon Field/Barrow Island in Western Australia	129 Mt	Deep saline aquifers	Sandstone & siltstones/shale	2700 m	4.9 Mt/year	2019	The sequestration thickness is 200–500 m.

The development of carbon sequestration technology is conducive to CCUS project decision-making. The first is the selection of reservoirs. Generally, the selection of reservoirs mainly focuses on (1) the sedimentary phase type (clastic rock, carbonate rock) and sedimentary environment of the reservoir (Figure 8); (2) sequestration depth, thickness, and three-dimensional geometry and integrity of the reservoir; (3) physical properties and heterogeneity of reservoir [60]. In this regard, Bachu et al. [61], Shen Pingping et al. [62], and Diao Yujie et al. [63] have successively proposed grading standards for CO_2 geological reservoir suitability evaluation (Table 3). Generally, the sequestration potential of the reservoir can be judged according to the existing physical simulation and numerical simulation

experiments, to further optimize the reservoir suitable for sequestration. For example, CO_2 geological sequestration in deep saline aquifers is generally carried out in sandstone and carbonate reservoirs. CO_2 will be stored in small spaces between the rock particles of these porous rocks. These spaces are not only conducive to the injection and penetration of CO_2, but also greatly improve the ability to store CO_2 [64,65].

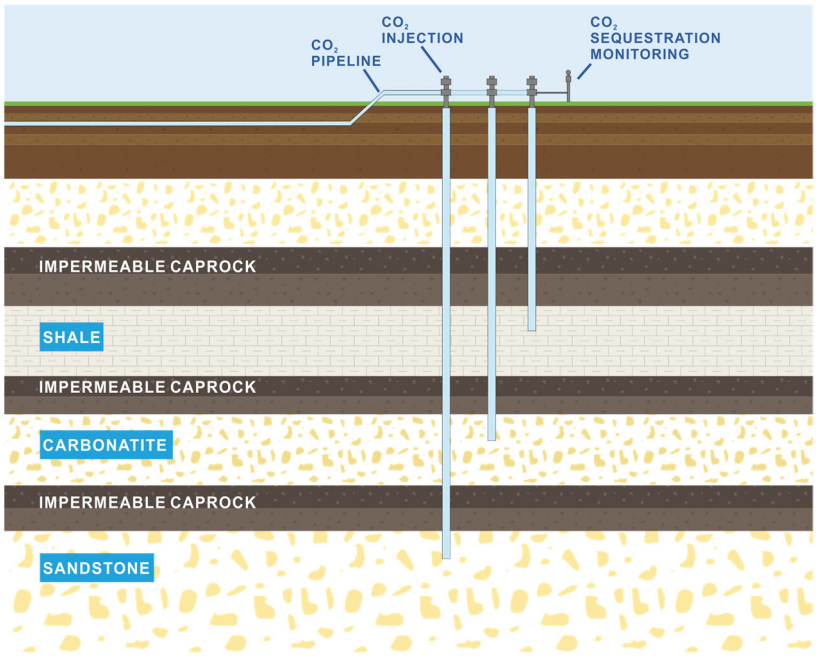


Figure 8. Reservoir lithofacies diagram (revising from [66]). In Table 2, the reservoir lithofacies of more than half of projects are sandstone.

Table 3. Reservoir stability assessment indexes and grading standards in target scale stages [63].

Grading Standard	Lithology	Single Layer Thickness h/m	Porosity φ	Permeability K/(10^{-3} μm^2)	Permeability Variation Coefficient V(K)	Distribution Continuity L/m	Hydrodynamic Conditions
Most appropriate	Clastic rock	≥10	≥25	≥1000	≤0.5	≥2000	Hydraulic sealing effect
Suitable	Clastic rock, carbonate mixed	5 ≤ h < 10	20 ≤ φ < 25	500 ≤ K < 1000	0.5 ≤ V(K) < 0.55	1200 ≤ L < 2000	Hydraulic sealing-blocking effect
Generally suitable	Carbonate	2 ≤ h < 5	10 ≤ φ < 20	50 ≤ K < 500	0.55 ≤ V(K) < 0.6	600 ≤ L < 1200	Hydraulic blocking effect
Less suitable	Magmatic rocks, metamorphic rocks, salt domes, and other special reservoirs.	1 ≤ h < 2	5 ≤ φ < 10	1 ≤ K < 50	0.6 ≤ V(K) < 0.65	300 ≤ L < 600	Hydraulic blocking–migration dissipation effect
Not suitable	\	<1	<5	<1	≥0.65	<300	Migration dissipation effect

When selecting a reservoir suitable for sequestration in the CCUS project, the program should not only pay attention to whether the reservoir storing CO_2 is suitable, but also pay attention to the selection of caprock, to avoid CO_2 leakage in the later sequestration process. Generally speaking, the thicker the caprock is, the more favorable it is for sequestration [67]. The common caprock lithology is divided into three categories: argillaceous rock accounts for about 70%, gypsum-salt rock accounts for about 20%, and carbonate rock and igneous rock account for about 10%; especially gypsum-salt rock and shale are excellent caprock lithology [68,69]. The caprock lithology, caprock distribution characteristics, caprock thickness, rock mechanical properties, and sealing pressure are the main factors affecting caprock

sealing. The sealing ability of caprocks with different lithology shows gypsum-salt rock > mudstone > carbonate rock > argillaceous siltstone [70]. Many projects will choose to carry out laboratory experiments to evaluate and use laboratory data directly. However, due to the large difference between laboratory conditions and actual conditions, such as medium properties, interfacial tension, and permeability, if they are directly used for evaluation without correction, there will be a large error between the experimental value and the true value of the evaluation parameters of caprock sealing. This is also a point that needs to be paid attention to before the actual use of laboratory data in the project.

The success of the CCUS project depends not only on the reservoir and caprock, including the location of the injection well, the selection of the injection rate, and the selection of the injection method, which will also affect the effect of the sequestration. In numerical simulations, especially for medium and long-term numerical simulation, compared with short-term simulation, the injection rate of CO_2 is less affected by the characteristics of CO_2 itself, reservoir rock, resident fluid, and injection process [71]. To enhance the sequestration effect of some projects, the injection point will be selected in the middle and lower part, which can increase the migration distance of CO_2 in the reservoir, and to a certain extent, it can also enhance the capture effect of residual gas [72]. The injection method will also adopt the method of alternating water and gas to improve the solubility of CO_2 and increase the total sequestration capacity. After the physical simulation experiment of CO_2–underground fluid–rock, Zhang Minglong et al. [73] studied the dynamic changes of formation fluid properties, fluid components, seepage characteristics, rock pore structure, and other parameters after CO_2 gas was injected into the formation. On this basis, the injection parameters and injection methods of the actual injection wells were adjusted. The initial gas continuous injection of the two wells was changed to water–gas alternating injection with a water–gas ratio of 1.5:1 and CO_2 foam injection with a water–gas ratio of 1:1. The daily oil production increased from 5.6 t to 15 t, and the CO_2 sequestration effect was greatly improved. Similarly, Rashid Mohamed Mkemai and Gong Bin conducted a numerical simulation of the Shenhua CCS project, using LandSim6 3D commercial modeling to analyze the parameters of injection rates, bottom hole flow pressure, and cumulative amount of stored CO_2 and established the optimal CO_2 injection scheme that will enhance CO_2 storage without endangering the safety of the caprock and the formation above it [74]. After the sequestration of CO_2, it should be monitored. Long-term stability is related to the behavior of CO_2 and the reservoir over longer time scales (from years to centuries or even millennia). This is related to the gradual migration of CO_2 in the reservoir, the continuous interaction between CO_2, reservoir fluids, and minerals, and the long-term risks associated with CO_2 corrosion of the wellbore leading to leakage or any other potential ways. [75,76]. Monitoring CCUS projects is not only for on-site safety issues, but also to avoid irreversible impacts on reservoirs and the environment. For example, CO_2 leakage will affect the ecological environment of soil and interfere with plant growth, pollute groundwater, and affect human health and may cause earthquakes [77]. At the same time, according to the successful implementation of CCUS projects in the past, it is also important to evaluate the economic benefits (transportation cost, pipeline cost, and commercial value) and deal with the policy issues; otherwise, it will also affect the rapid development of CCUS projects.

The processes of confirming the sequestration potential, selecting the sequestration reservoirs, and the well location, injection rate, methods, and temperature of the injection well during sequestration are all related to the CO_2 water–rock interaction. A deep understanding of the CO_2 water–rock interaction mechanism can provide scientific and technical guidance for carbon sequestration, which is conducive to improve carbon sequestration technology.

6. Conclusions

This paper reviews the research methods, cognition, and reservoir selection of CO_2 water–rock interaction. (1) For the two research methods of physical simulation and cross-time scale numerical simulation based on formation temperature and pressure conditions,

high-precision mineral-pore in situ comparison and physical property evolution evaluation are important development directions, which can improve the accuracy of physical simulation experiment data and lay a good foundation for numerical simulation. At the same time, the development of numerical simulation requires not only a large amount of experimental data, but also field data for feedback, corresponding to the improved model, so that it can predict more accurately, so as to avoid possible problems and improve CO_2 sequestration efficiency. (2) There is no uniform standard for the main factors affecting the changes of minerals, pore structure, and physical properties in CO_2 water–rock interaction. Formation conditions and geological background are important factors affecting mineral changes, and generally carbonate minerals react most obviously. The precipitation or dissolution of minerals affects the different changes of pore structure and physical properties. Mineral dissolution may lead to the increase of average pore diameter or the development of fractures, and mineral precipitation or expansion may also lead to the decrease of average pore diameter or the blockage of original fractures, and it also involves the expansion effect of some clay minerals. The reaction rate and migration of minerals are also the factors affecting the change of physical properties. (3) The study of CO_2 water–rock interaction is helpful to improve the effect of carbon sequestration. It is not only beneficial to evaluate the potential of carbon sequestration, but also can improve the efficiency of carbon sequestration and optimize the CCUS scheme from the aspects of CO_2 injection method, rate, and duration.

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