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Review Paper

CO_2 storage with enhanced gas recovery (CSEGR): A review of experimental and numerical studies

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A B S T R A C T

CO_2 emission mitigation is one of the most critical research frontiers. As a promising option of carbon capture, utilization and storage (CCUS), CO_2 storage with enhanced gas recovery (CSEGR) can reduce CO_2 emission by sequestrating it into gas reservoirs and simultaneously enhance natural gas production. Over the past decades, the displacement behaviour of CO_2–natural gas has been extensively studied and demonstrated to play a key role on both CO_2 geologic storage and gas recovery performance.

This work thoroughly and critically reviews the experimental and numerical simulation studies of CO_2 displacing natural gas, along with both CSEGR research and demonstration projects at various scales. The physical property difference between CO_2 and natural gas, especially density and viscosity, lays the foundation of CSEGR. Previous experiments on displacement behaviour and dispersion characteristics of CO_2/natural gas revealed the fundamental mixing characteristics in porous media, which is one key factor of gas recovery efficiency and warrants further study. Preliminary numerical simulations demonstrated that it is technically and economically feasible to apply CSEGR in depleted gas reservoirs. However, CO_2 preferential flow pathways are easy to form (due to reservoir heterogeneity) and thus adversely compromise CSEGR performance. This preferential flow can be slowed down by connate or injected water. Additionally, the optimization of CO_2 injection strategies is essential for improving gas recovery and CO_2 storage, which needs further study. The successful K12–B pilot project provides insightful field-scale knowledge and experience, which paves a good foundation for commercial application. More experiments, simulations, research and demonstration projects are needed to facilitate the maturation of the CSEGR technology.

1. Introduction

CO_2 concentration in the atmosphere has raised to a new high level of 407.8 ppm in 2018, 147% of pre-industrial levels in 1750 (280 ppm) (WMO, 2019). Such a high concentration is widely believed to be one of the main reasons for global warming (IPCC, 2013; Liu et al., 2018a; Metz et al., 2005; Najafi-Marghmaleki et al., 2017; Ren et al., 2018; Wangler et al., 2018). CO_2 capture, utilization and storage (CCUS) is regarded as one of the most important technologies for CO_2 emission mitigation (Xu et al., 2007). In CCUS, CO_2 is captured from emission sources (e.g., power plants), transported, and then permanently sequestered into underground formations, such as deep saline aquifers and hydrocarbon reservoirs. The captured CO_2 can also be used to improve

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the recovery of underground resources, such as water/oil/gas/coalbed-methane (Hamza et al., 2021; Luu et al., 2016; Ren et al., 2019; Rogala et al., 2014; Wang et al., 2016, 2020; Xie et al., 2014).

As one of promising CCUS options, CO_2 storage with enhanced gas recovery (CSEGR or CO_2-EGR) can promote the extraction of natural gas by permanently sequestrating CO_2 into gas reservoirs (Tang et al., 2015). The concept of CSEGR was originally proposed by van der Burgt et al. (1992) in the 1990s. The process is to inject CO_2 into a depleted gas reservoir for re-pressurizing and displacing the remaining natural gas that cannot be exploited by conventional technologies (Al-Hasami et al., 2005; Clemens and Wit, 2002). The schematic diagram of the process is in Fig. 1.

CSEGR has several unique advantages. The geological structure of the gas reservoir is suitable for the long-term storage of gaseous substances, such as CO_2. Since gas storage capacities and caprock integrity have been self-verified, the risk of CO_2 leakage is low (Oldenburg and Benson, 2001). The formation data and reservoir model of a target natural gas reservoir should have been collected during reservoir development. This is critical for managing the CSEGR operation (Oldenburg and Benson, 2001). The wells, gathering facility, transportation pipeline network and other infrastructures are readily available and can be re-purposed for CO_2 injection (Oldenburg and Benson, 2002; Oldenburg et al., 2001). More importantly, enhanced natural gas production by CO_2 injection brings more revenue and can offset storage cost to some extent.

CO_2 storage capacities in natural gas reservoirs are significant. According to the International Energy Agency (IEA) (Wildgust, 2009) and Carbon Storage Leadership Forum (CSLF) (McKee, 2013), the worldwide CO_2 storage capacity of conventional natural gas reservoirs reaches 160–390 Gt. In addition, simulation studies (Al-Hasami et al., 2005; Jikich et al., 2003) have shown that natural gas production can be enhanced by 5%–15% when applying CSEGR. The experience of the K12–B pilot project demonstrated that about 0.03–0.05 ton natural gas can be extracted per ton of CO_2 injected (van der Meer et al., 2006). Previous work has also shown that, if CSEGR is applied to all proved natural gas reservoirs in China, an incremental natural gas production of (63.9–191.7) $\times$ 10^9 Nm^3 can be obtained via CSEGR (Zhang et al., 2013), and meanwhile the incidental CO_2 storage is more than 5.18 Gt (Li et al., 2009). Therefore, CSEGR has huge potentials in both sequestering CO_2 for environmental consideration and enhancing gas production for economic benefits.

Although the technical feasibility of CSEGR has been preliminarily proved by reservoir simulations and demonstration projects (Oldenburg et al., 2001; van der Meer et al., 2005), the technology is not fully or commercially ready. Many researchers have thus been conducting experiment and simulation studies of CO_2 displacing natural gas in porous media at laboratory or field scales. We review these studies in this work, with an emphasis on CO_2-natural gas displacement. Our objective is to bring a comprehensive understanding based on previous work and meanwhile provide useful insights for future work.

Notably, we focus on reviewing the literature about CSEGR for conventional natural gas reservoirs. Some studies are focused on unconventional ones, such as CO_2 injection into brines for extracting dissolved CH_4 (Jenkins et al., 2012; Li and Li, 2015; Taggart, 2009; van der Meer, 2005), CO_2 enhanced condensate recovery (Al-Abri and Amin, 2010; Al-Abri et al., 2009, 2012; Shtepani, 2006), CO_2 enhanced shale gas recovery (Liu et al.,

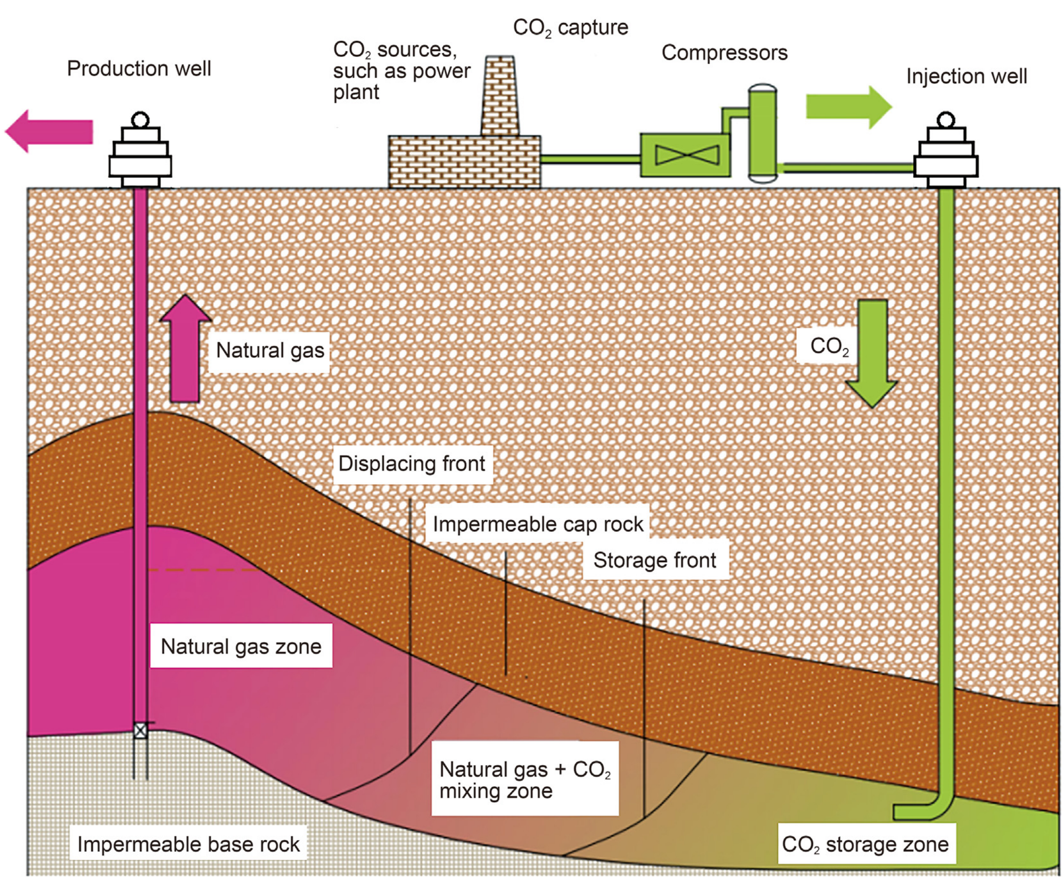

Fig. 1. Schematic diagram of the CSEGR system (Liu, 2018).

2020b), and replacement of methane hydrate by CO_2 (Wang et al., 2020; Zhang et al., 2017). These studies are out of the scope of our review objective.

The organization of this paper is as follows. Section 2 compares the difference in physical properties (density and viscosity) between CO_2 and natural gas. Section 3 reviews the laboratory experiments of CO_2-natural gas displacements, in both consolidated and unconsolidated cores. Section 4 describes the simulation studies of CSEGR at field-scale, including CSEGR feasibility and optimization studies and associated parametric analysis on both reservoir properties and injection parameters. Section 5 is focused on main CSEGR research and demonstration projects. The final section is conclusions and future research recommendations.

2. Comparison of physical properties between CO_2 and natural gas

The natural gas in conventional dry gas reservoirs mainly consists of CH_4 (>95%), other hydrocarbons (C_{2+}), and inorganic gas (CO_2, N_2, H_2S, etc.). CH_4 is the dominant component. Under the atmospheric condition, CO_2 and CH_4 are at the gaseous state and easy to mix with each other. However, the physical properties (e.g., density and viscosity) of CO_2 and CH_4 are significantly different at typical reservoir conditions, which reduces the likelihood of the reservoir natural gas being contaminated by injected CO_2.

Fig. 2 shows the phase diagram of CO_2. CO_2 mainly stays at a supercritical state (the critical temperature and pressure of CO_2 are 31.1 °C and 7.38 MPa, respectively) under typical reservoir conditions (burial depth >800 m). At the supercritical state, CO_2 has a density close to liquid which is almost two orders of magnitude larger than natural gas (Fig. 3). The density difference between CO_2 and CH_4 causes gravity segregation. The denser CO_2 tends to sink into the bottom of the reservoir to form "cushion gas" beneath the lower-density natural gas (Oldenburg et al., 2001), which favors updip natural gas production.

In addition, the viscosity of CO_2 is about one order of magnitude larger than CH_4 at the reservoir conditions (Biagi et al., 2016; Oldenburg and Benson, 2001) as shown in Fig. 3. The displacement of CH_4 by CO_2 benefits from the large viscosity of CO_2 because of the favorable mobility ratio between CO_2 and CH_4 (Oldenburg and Benson, 2002).

In sum, the different physical properties between CO_2 and CH_4 is advantageous to re-pressurize the reservoir and to displace natural gas by sequestering liquid-like CO_2 at the bottom of a given reservoir. The contamination of the remaining natural gas in-place by CO_2 might be concerning, and we will specifically review this below.

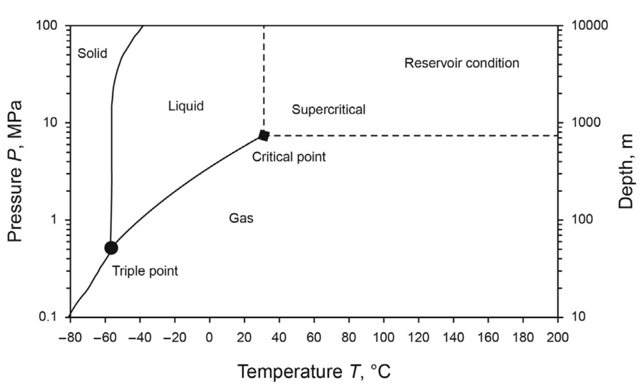

Fig. 2. Phase diagram showing that CO_2 will normally be supercritical in natural gas reservoirs.

3. Laboratory experiments of CO_2–natural gas displacement

Many experiments of CO_2–natural gas displacements in consolidated and unconsolidated cores were designed and conducted to reveal the characteristics of CO_2 displacement, mixing between CO_2 and natural gas, and natural gas recovery. They are reviewed in this section.

For a displacement test, the porous media is pre-saturated by a displaced fluid, then a displacing fluid is injected into the porous media in the form of either continuous or pulse flow to displace the pre-saturated fluid. In the process of CO_2 displacing natural gas in underground formations, they will mix to form a mixing zone due to convection and diffusion. The mixing zone and the mixing degree are critical to displacement efficiency, natural gas recovery, and CO_2 storage in CSEGR.

Dispersion is a mixing phenomenon between two kinds of fluids linked to the heterogeneity of the microscopic velocities inside porous media, and the dispersion coefficient is used to quantitatively describe the mixing degree (Blackwell, 1962; Delgado, 2006; Perkins and Johnston, 1963). Thus, the formation of dispersion in the process of one fluid displacing another one in porous media is caused by convection and diffusion. The dispersion coefficient is usually evaluated by the convection-dispersion equation. The one-dimensional convection-dispersion equation is written as,

$$D_L \frac{\partial^2 C}{\partial x^2} - v \frac{\partial C}{\partial x} = \frac{\partial C}{\partial t} \tag{1}$$

where D_L is the longitudinal dispersion coefficient, the first term on the left-hand side is the convection, the second term is the hydrodynamic dispersion, and $\frac{\partial C}{\partial t}$ is the change in concentration over time. Dispersion is an important physical mechanism of mixing during CO_2 displacing CH_4 in CSEGR (Honari et al., 2013). Thus, some work focused on the influence of dispersion on CO_2–CH_4 displacement in porous media for CSEGR.

3.1. CO_2-natural gas displacement in consolidated cores

Consolidated cores are close to real reservoir conditions. Thus, many studies of CO_2–natural gas displacement experiments were conducted in consolidated cores for CSEGR, and these studies are summarized in Table 1. The experimental temperature and pressure ranges for these studies are also listed in Fig. 4, with the temperature in the range of 20–160 °C and pressure up to 45 MPa. Most of the experiments were under the condition of temperatures 20–100 °C and pressures 5–15 MPa. These experiments provide practical insights of displacement characteristics.

Notably, Mamora and Seo (2002) and later Seo and Mamora (2005) performed an experiment study of CO_2 displacing CH_4 in carbonate cores. Their results showed that CH_4 recovery was in the range of 73%–87% before CO_2 breakthrough. The dispersion coefficient (0.01–0.12 cm^2/min) of CO_2–CH_4 was calculated by fitting the convection-dispersion equation, and the coefficient increases with temperature and pressure. Specifically, the core CT images at CO_2 breakthrough in Mamora and Seo (2002) and Seo and Mamora (2005) indicated that the CO_2 distribution is not uniform on the cross-section along the axial direction of the carbonate core, and channels exist for CO_2 to preferentially flow through.

The impurity in displacing or displaced fluids significantly influences displacement behaviour. Nogueira (2005) showed that the injection of dehydrated flue gas (CO_2 content of 13.574%) reduces CH_4 recovery by about 10%, and the dispersion coefficient increases by 20%–67% compared to that of CO_2 injection. In contrast to the method of convection–dispersion equation for dispersion coefficient calculation, Sidiq and Amin (2009) proposed a

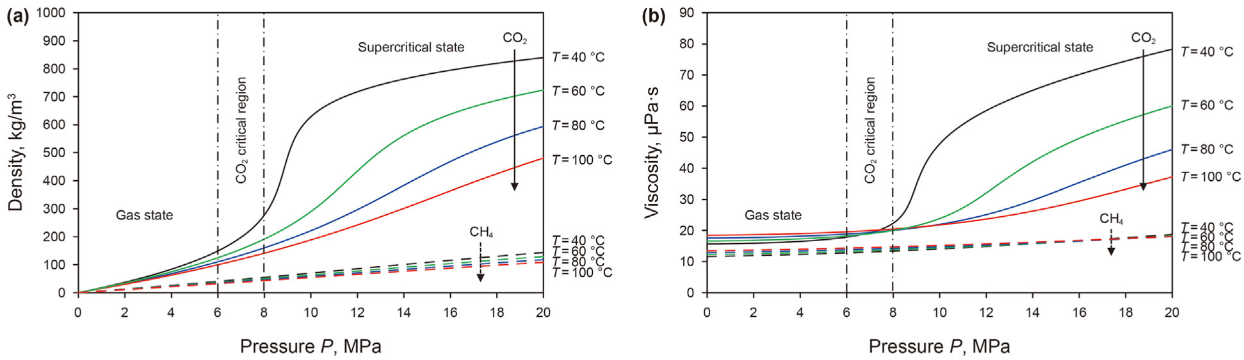

Fig. 3. Typical physical properties of CO_2 and CH_4 at temperature of 40, 60 80 and 100 °C: (**a**) density, (**b**) viscosity.

Table 1
Experiment studies of CO_2–natural gas displacement in consolidated cores for CSEGR.

Research focus	Studies	Core type and size $\Phi \times L$	Porosity ϕ Permeability k, mD	Pressure P, MPa Temperature T, °C
Technical feasibility test of GSEGR	Mamora and Seo (2002); Seo and Mamora (2005)	Carbonate 2.54 cm × 30.5 cm	ϕ: 0.23 k: 50	P: 3.5–20.8 T: 20–60
Impact of impurity compositions	Nogueira (2005)	Carbonate 2.54 cm × 30.5 cm	ϕ: 0.21–0.23	P: 10.3 T: 70
	Sidiq and Amin (2009, 2010, 2012)	Sandstone 1.975 cm × 19.41 cm	ϕ: 0.143 k: 92.5	P: 40.679 T: 160
Gravity effect and entry/exit effect on measurement of dispersion coefficient	Hughes et al. (2012)	Sandstones 3.81 cm × 5 cm 3.81 cm × 10 cm	ϕ: 0.20, 0.16 k: 460, 12	P: 8–12 T: 40–80
	Li et al. (2019)	Sandstone and carbonate 2.5 cm × 7.6–7.7 cm	ϕ: 0.20, 0.17 k: 100, 70	P: 10 T: 20, 40
Core dispersivity	Honari et al. (2013, 2015a)	Sandstones, carbonates 3.76 cm × 5 cm 3.76 cm × 10 cm	ϕ: 0.20, 0.16, 0.15, 0.28, 0.22 k: 460, 12, 210, 2910	P: 8–14 T: 40–100
Impact of irreducible (residual) water	Turta et al. (2008)	Berea core 3.81 cm × 30.48 cm	ϕ: 0.25 k: 500	P: 6.2 T: 70
	Honari et al. (2016)	Sandstones, carbonate 3.75–3.80 cm × 10.04 –10.47 cm	ϕ: 020, 0.16, 0.23 k: 460, 12, 2912	P: 10 T: 40
	Zecca et al. (2017)	Sandstones 3.75–3.76 cm × 10.04 –10.10 cm	ϕ: 0.20, 0.15 k: 460, 12	P: 10 T: 36
	Abba et al. (2017, 2018b)	Berea, sandstone 2.522 cm × 7.627 cm	ϕ: 0.203 k: 217	P: 8.963 T: 40
CO_2 horizontally displacing CH_4	Abba et al. (2018a, 2019)	Sandstones 2.5 cm × 7.6 cm	ϕ: 0.19–0.26 k: 200–315, 30, 350 –600	P: 8.963 T: 50

straightforward method using a single point at the initial rise of a breakthrough curve. The dispersion coefficient is proportional to purity of the displaced phase, and the dispersion coefficient decreases with the increase in injection pressure. The purity of in-situ gas and pore pressure were identified as two key factors on the displacement efficiency. Sidiq and Amin (2010, 2012) further focused on the impact of pore pressure on supercritical CO_2 displacing natural gas (90% CH_4 + 10% CO_2) in a sandstone core with connate water. Results confirmed that the greater difference in physical properties in a CO_2–CH_4 system under large pore pressure will result in improved recovery and limited mixing.

The effects of gravity and entry/exit of coreflooding are key factors on the measurement of dispersion coefficient. Hughes et al. (2012) analyzed the gravity effect and entry/exit effect on the measurement of dispersion coefficients of CO_2–CH_4 displacement in sandstone cores. The results showed that the entry/exit effect can result in the apparent dispersion coefficient up to 63% larger than the internal one in the core. The gravity effect restrained vertical dispersion, but accelerated horizontal dispersion especially at a low injection rate in a high-permeability core. Later, Li et al. (2019) applied one-dimensional MRI to in-situ measure the dispersion process and draw a similar conclusion as Hughes et al. (2012). Honari et al. (2013) improved the displacement experiments by employing pulsed injection of CO_2 to measure dispersion coefficient. The work analyzed the relationship between dispersion and the Peclet number to obtain core dispersivity (representing the characteristic length of mixing in a core). Subsequently, the phenomenon of premature CO_2 breakthrough and tailing of the breakthrough curve was observed in heterogeneous carbonate cores in Honari et al. (2015a). The dispersion coefficient calculated by Mobile-Immobile Model (MIM) is much larger in carbonates than that in sandstones because the former is typically more heterogeneous than latter.

Formation water largely influences CO_2–natural gas displacement and mixing characteristics, as demonstrated by recent work. With the existence of irreducible water, Turta et al. (2008) showed

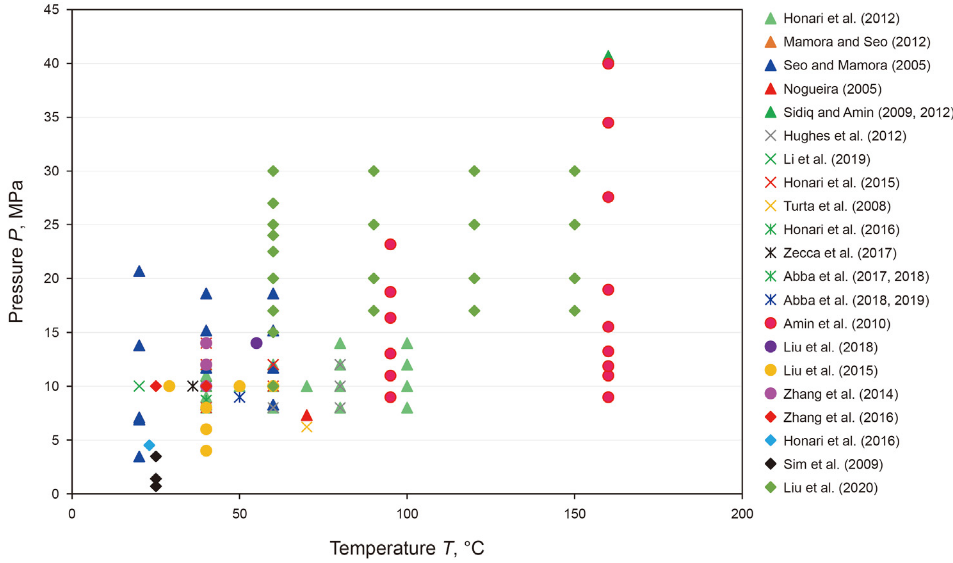

Fig. 4. The temperature and pressure ranges of experimental studies of CO_2–natural gas displacement for CSEGR.

that the recovery factor is significantly improved by CO_2 injection. Additionally, Honari et al. (2016) showed that the irreducible water occupies some flow channels, dissolved part of CO_2, and effectively reduces the bad influence of core heterogeneity on sweep. Thus, the CH_4 recovery factor was improved. Besides, Honari et al. (2016) proposed that the delay of CO_2 transport causes a tailing in the breakthrough curve and non-Fick phenomenon, and aggravates the dispersion in CO_2–CH_4 displacement. Zecca et al. (2017) observed that the dispersivity increases significantly with the water saturation in a core, and an empirical function was built correspondingly. Abba et al. (2018b) extended the study to include the effect of connate water salinity. The results indicated that the dispersion coefficient decreases with increasing salinity. In this sense, connate water salinity affects the mixing of CO_2 and residual natural gas in the reservoir.

Besides the above studies on vertical CO_2–CH_4 displacement, Abba et al. (2018a, 2019) conducted the horizontal CO_2–CH_4 displacement on dispersion characteristics in consolidated sandstones. The measured horizontal dispersion coefficients were overall 20%–30% larger than the vertical ones. Abba et al. (2019) showed that the dispersion coefficient increases with decreasing permeability.

In addition to dispersion studies, Amin et al. (2010) proposed "interface" and "interfacial tension" during the process of CO_2 displacing natural gas. However, Hughes et al. (2012) proposed that the "interfacial tension" measured by Amin et al. (2010) might occur due to the "Korteweg stresses", which is a "transient stresses in dynamic interfaces between miscible fluids induced by density gradient"(Korteweg, 1901; Morra and Yuen, 2008).

3.2. CO_2-natural gas displacement in unconsolidated porous media

In addition to consolidated cores, some studies of CO_2–natural gas displacement were conducted in unconsolidated ones (Liu et al., 2018b). The use of unconsolidated porous media favours for the design of homogeneous core flooding experiments, visualization of displacement, analysis of influential factors, and in-situ measurement of dispersion. The important studies on CO_2-natural gas displacement in unconsolidated porous media are listed in Table 2.

Before the idea of CSEGR was proposed, some experiment studies on the dispersion characteristics in the displacement experiments were usually conducted in sand packed samples (Delgado, 2006; Perkins and Johnston, 1963), with the mode of either CO_2 displacing CH_4 or CH_4 displacing CO_2 (Tan and Liou, 1989; Yu et al., 1999). They are different from the settings of CSEGR.

For CSEGR, Liu et al. (2015) and Zhang et al. (2014) evaluated the influential factors of dispersion by conducting CO_2–CH_4 displacement experiments in a sand pack of glass beads. The results revealed that the dispersion coefficient increased with both temperature and flow rate, and the pressure influence is complicated around the critical region. Liu et al. (2015) also visually described the CO_2–CH_4 displacement behavior by micro X-ray CT. The in-situ visual observation confirmed that the mixing transition zone existed at the displacing front as a limited zone, and no interface appeared in the process of supercritical CO_2 displacing CH_4.

Zhang et al. (2016) proposed an in-situ measurement method for dispersion coefficient of liquid/supercritical CO_2–CH_4 displacement. The component concentration of CO_2–CH_4 mixtures in the pore space of sand pack was obtained by processing the grey value of CT image which describes the mixing degree of CO_2 and natural gas, and the Crank–Nicolson method was employed to solve the convection–dispersion equation for the calculation of the dispersion coefficient. They showed that the entry/exit artifacts cause an overestimation of the dispersion coefficients by 14%–23%. In addition, Honari et al. (2015b) evaluated the entry/exit artifacts by employing the low-field MRI technology, which is in the range of 8%–32%, lower than these in the consolidated core in Hughes et al. (2012).

The effect of gas compositions in the displacing or displaced fluid was also conducted in unconsolidated cores. Sim et al. (2009) compared CO_2 and N_2 displacing CH_4 in sand-packed samples containing irreducible water. Results show that the recovery factor is higher when CO_2 is used as the displacing fluid compared to N_2. The dispersion characteristics were not analyzed by Sim et al. (2009). Later, Liu et al. (2018b) conducted the experiments of CO_2 horizontally displacing the simulated natural gas (SNG, composed of 90% CH_4 + 10% CO_2). The presence of CO_2 in the SNG renders the SNG easier to be mixed with the injected CO_2, which results in more significant horizontal dispersion.

Liu et al. (2020c) compared the apparent dispersion coefficient of CO_2–CH_4 displacement in both vertical and horizontal directions in a large range of temperature (60–150 °C) and pressure

Table 2
Experiment studies of CO_2-natural gas displacement in unconsolidated cores for CSEGR.

Research focus	Studies	Core type and size $\Phi \times L$	Grain size (diameter)	Porosity ϕ Permeability k, mD	Pressure P, MPa Temperature T, °C
Effects of various factors on dispersion	Liu et al. (2015); Zhang et al. (2014)	Glass beads sand pack (BZ04, BZ06, BZ08, BZ1, BZ2) 1.5 cm × 15 cm	0.43, 0.60, 0.71,1.19, 2.00 mm	ϕ: 0.331–0.41 k: 22,250 –50,900	P: 4–14 T: 29–60
In-situ method of dispersion coefficient measurement	Zhang et al. (2016)	Glass beads sand pack (BZ01, BZ04) 1.5 cm × 12 cm	0.12, 0.40 mm	ϕ: 0.324, 0.330	P: 10 T: 25, 40
	Honari et al. (2015b)	Borosilicate glass beads 2.9 cm × 8.1 cm	100 μm	ϕ: 0.395	P: 4.5 T: 23
Impact of impurity compositions	Sim et al. (2009)	Silica sand pack 4.14 cm × 200 cm	45–106 μm	ϕ: 0.43 k: 2000	P: 0.69, 1.38, 3.45 T: room temperature (25)
	Liu et al. (2018b)	Glass beads sand pack (BZ01) 1.6 cm × 12, 20 cm	0.1 mm	ϕ: 0.324 k: 11200	P: 10, 14 T: 40, 55
CO_2 horizontally displacing CH_4	Liu et al. (2020c)	Glass beads sand pack (BZ01, BZ04, BZ1) 1.6 cm × 12, 21 cm	0.12, 0.43, 1.19 mm	ϕ: 0.331 –0.384 k: 7,800 –42,400	P: 10–30 T: 60–150

(10–30 MPa). The results showed that the horizontal dispersion coefficients are much higher than the vertical ones, which is similar to the phenomenon in consolidated cores.

The previous experiment studies reviewed above preliminarily verified the feasibility of CO_2 displacing natural gas for enhancing gas recovery due to the limited mixing. The in-situ CT and MRI visualization studies confirmed the mixing transition zone exists in the displacement. The mixability of CO_2–natural gas displacement is quantitatively analyzed by the measurement of dispersion coefficient. Previous experiment studies of dispersion coefficient measurement reveal the basic changing rule of mixability of CO_2–natural gas displacement in CSEGR. However, accurate dispersion measurements considering the complex condition of the gas reservoir, such as impure CO_2 injection, connate water, and heterogeneity, are still insufficient, and more related studies are essential to obtain the accurate mixing parameters for reservoir simulation.

4. CSEGR numerical simulation at reservoir scales

Numerical simulation is an effective way to study the flow and mass transfer during CO_2–natural gas displacement in reservoirs and thus help assess a CSEGR project. Therefore, many studies of CSEGR simulations have been performed. These studies include the analysis of the effect of reservoir formation properties and CO_2 injection parameters and optimization of injection strategies for both gas recovery and CO_2 sequestration.

4.1. CSEGR feasibility studies

In the 1990s, van der Burgt et al. (1992) simulated a CO_2 disposal process by injecting CO_2 into the depleted gas fields, in which CO_2 was captured from the coal-based IGCC's power plant and sequestrated into the underground formation with enhanced natural gas production from the reservoir. Blok et al. (1997) further proposed to combine hydrogen production from natural gas with CO_2 removal by compressing and injecting the separated CO_2 into the depleted gas reservoirs for CO_2 sequestration and enhancing natural gas recovery. van der Burgt et al. (1992) and Blok et al. (1997) preliminarily investigated the feasibility of CSEGR by simulation when they first proposed the original concept of CSEGR. The main studies on CSEGR feasibility are presented in Table 3.

The technical and economic feasibility of CSEGR is the research focus at the beginning stage of the CSEGR study. Oldenburg (2003), Oldenburg and Benson (2001, 2002), Oldenburg et al. (2001, 2004) and Rebscher and Oldenburg (2005) conducted a series of simulation work to discuss the technical and economic feasibility of CSEGR. Oldenburg et al. (2001) and Oldenburg and Benson (2001) discussed the technical feasibility of CSEGR in the Rio Vista Gas Field in the Central Valley of California, US by qualitatively analyzing the difference in physical properties (density and viscosity) between CO_2 and natural gas, which has been presented in Section 2. Theoretically, the possibility of mixing between supercritical CO_2 and natural gas is very limited due to their significant difference in density and viscosity, shown in Fig. 3. Then the implementation of CO_2-EGR in the depleted Rio Vista gas field was simulated in a two-dimensional model. They found that additional CH_4 can be produced from depleted gas reservoirs by CO_2 injection, which proved the CSEGR's technical feasibility. Oldenburg and Benson (2001) even proposed the main criteria for a field site to implementing CSEGR: small reservoir volume and high permeability were considered favorable for re-pressurization and enhanced gas recovery over a reasonably short period. Oldenburg et al. (2001) further extended the study of CSEGR's technical feasibility by using a three-dimensional depleted gas reservoir model in the Rio Vista Gas Field. It's proposed that injecting CO_2 into the deeper levels and extracting natural gas from the higher levels of the gas reservoir can contribute to forming an effective vertical CO_2–natural gas displacement due to the strong density contrast. Thus, the upwelling of the mixing of CO_2 with the remaining natural gas in the reservoir was inhibited in this case. In addition, Oldenburg (2003) suggested that it's technically feasible to implement CSEGR in the depleting gas reservoirs with considering CO_2 as a "cushion gas". The simulation of Rebscher and Oldenburg (2005) and Ganzer et al. (2013) in the almost depleted gas field Salzwedel-Peckensen, Altmark in North Germany, and Klimkowski et al. (2015) and Papiernik et al. (2015) in the Załęcze Gas Field in Poland also illustrated that the CSEGR was technically feasible. Hussen et al. (2012) conducted simulation of CSEGR applied in a high-pressure reservoir with the temperature above its critical point and proved the technical feasibility of CSEGR, especially that CO_2 injection into the reservoir at a high rate and late stage of the field life is more favorable. Khan et al. (2013) verified that CSEGR is technically feasible especially that a higher CO_2 injection rate favors the significant improvement of gas recovery and CO_2 storage. Patel et al. (2016) also verified the technical feasibility of CSEGR with considering the dispersion between CO_2 and natural gas by conducting the high-fidelity reservoir simulations, and it emphasized that accurate reservoir simulations with high fidelity were important for CO_2-EGR.

Table 3
Main simulation studies on the technical and economic feasibility CSEGR.

Studies	Simulator	Model size $x \times y \times z$	Porosity ϕ Permeability k, mD	Pressure P, MPa Temperature T, °C	CO_2 injection rate, t/d
van der Burgt et al. (1992)	/	4 km × 12.5 km × 68 m 2 km × 7 km × 68 m	ϕ: 0.12 k_x: 80 k_z: 1.6	P: 3–35	15000
Blok et al. (1997)	/	4 km × 12.5 km × 68 m	ϕ: 0.05–0.14 k_x: 1–600	P: 3–35	15068
Oldenburg and Benson (2001); Oldenburg et al. (2001)	TOUGH2	6.6 km × 1 km × 100 m	ϕ: 0.35 k_x: 1,000 k_z: 10	P: 12 T: 65	708.48
Rebscher and Oldenburg (2005)	TOUGH2	2.1 km × 2.1 km × 226 m	ϕ: 0.05–0.15 k: 0.05–10000	P: 20 T: 120	69.12–1382.4
Ganzer et al. (2013)	ECLIPSE	9 km × 3 km × 17.07 m	ϕ: 0.022–0.225 k_x: 0.03–97.62 $k_z/k_x = 0.3$	P: 42.4 T: 125	143–200
Klimkowski et al. (2015); Papiernik et al. (2015)	Petrel, CMG, FLAC3D	8.6 km × 8.0 km × 200 m	ϕ: 0.185 k_x: 5–50	P: 15.1 T: 45	2,465.75
Khan et al. (2013)	Tempest	1.7 km × 2.3 km × 300 m	ϕ: 0.04–0.17 k_x: 6–390 k_z: 4–370	P: 40.6 T: 160	4838–2546
Patel et al. (2016)	COMSOL	201.19 m × 201.19 m × 45.72 m	ϕ: 0.23 k_x: 5–100 k_z: 0.5–10	P: 9.1 T: 75	2.756–275.6
Oldenburg et al. (2004)	TOUGH2	800 m × 800 m × 50 m	ϕ: 0.3 k_x:1000	P: 5 T: 75	260
Al-Hasami et al. (2005)	/	1219.2 m × 1219.2 m × 36.58 m	ϕ: 0.2 k_x: 40	P: 41.37 T: 100	0.113–1,130
Hussen et al. (2012)	Tempest	1.7 km × 2.3 km × 300 m	ϕ: 0.04–0.17 k_x: 6–390 k_z: 4–370	P: 40.6 T: 160	4,838

Note: "/" in the table denotes absence of data; k_x is the horizontal reservoir permeability while k_z is the vertical one, and k_x is usually 10 times of k_z.

Moreover, Oldenburg et al. (2004) showed that the economics of CSEGR implemented in the depleted and low-pressure Rio Vista gas reservoir is sensitive to many factors, such as wellhead prices of natural gas, CO_2 supply cost, etc. Generally, CSEGR will be considerably more favorable when CO_2 supply is low cost or carbon tax is imposed for CO_2 emission reduction. Similar to Oldenburg et al. (2004), simulation results of Al-Hasami et al. (2005) and Hussen et al. (2012) verified that the economics of CSEGR is sensitive to market prices of natural gas, CO_2 supply, mixing of CO_2 and natural gas, etc. Khan et al. (2013) proposed that CSEGR is more economically favorable while effective payments for CO_2 storage in the future carbon market will be more attractive.

In sum, previous simulations showed that generally, CSEGR is technically feasible to be employed in gas fields, especially the depleted gas fields. From the view of the economic feasibility, CSEGR will be more economically feasible if implementing a carbon tax policy or effective payments for CO_2 storage. However, for a specific gas reservoir to apply CSEGR, the simulation is still needed to test the technical and economic feasibility.

4.2. Study on the effect of reservoir properties and injection parameters

The reservoir formation characteristics and CO_2 injection parameters have a key role in the underground displacement of CO_2–natural gas, then significantly affecting enhanced gas recovery and CO_2 storage when implementing CSEGR. Table 4 shows the studies of the impact of reservoir heterogeneity, CO_2 injection timing and rate, well patterns and other factors on the displacement of CO_2-natural gas.

Oldenburg et al. (2001) presented that permeability heterogeneity favors the formation of fast flow paths and tends to accelerate CO_2 breakthrough. The CSEGR simulation in Altmark Field (Germany) of Rebscher and Oldenburg (2005) and CO_2CRC Otway Project (Australia) of Ennis-King et al. (2011) also revealed that CO_2 preferentially broke through in the geological layer with high permeability in the heterogeneous reservoirs, which is harmful to natural gas recovery. Luo et al. (2013), Kalra and Wu (2014) and Fan et al. (2021) got similar conclusions. Wang et al. (2010) revealed that the preferential pathway due to the fracture-induced has a dramatic impact on earlier CO_2 breakthrough and further affects the overall gas recovery. To stabilize the displacement process, Rebscher and Oldenburg (2005), Al-Hasami et al. (2005) and Kalra and Wu (2014) proposed that the injected water or formation water in the high-permeability layers can delay CO_2 breakthrough by efficiently blocking the fast flow path and CO_2 dissolution. Patel et al. (2017) showed that the inclusion of connate water has a large effect on changing the CO_2 flow field, causing a reduction in CO_2 breakthrough time, and however, the connate water may result in a decrease in methane recovery. Patel et al. (2017) indicated that these effects of connate water were sensitive to well perforation depth, which should be studied systematically. Feather and Archer (2010) confirmed that low permeability, isotropic and homogeneous reservoir is a good target of CO_2-EGR application.

To explore the optimal timing of CO_2 injection, Clemens and Wit (2002) and Liu et al. (2020a) analyzed the impact of CO_2 injection on the natural gas recovery factor at different development stages of the gas field. It's found that to inject CO_2 when the gas reservoir was depleted can promote the maximum gas recovery. The premature injection of CO_2 at the early stage of gas field development was proved harmful to recovery. By conducting a simulation study of CSEGR in a sandstone reservoir in Northern West Virginia, Jikich et al. (2003) obtained similar results as Clemens and Wit (2002).

In addition to injection timing, the injection rate of CO_2 is another key injection parameter on CSEGR. Recovery factor is shown to increase with injection rate within a certain range by Seo and Mamora (2005). Hussen et al. (2012) and Feather and Archer (2010) obtained a similar conclusion that it is more beneficial for

Table 4
Main simulation studies of CSEGR on the effect of reservoir properties and injection parameters.

Research focus	Studies	Simulator	Model size $x \times y \times z$	Porosity ϕ Permeability k, mD	Pressure P, MPa Temperature T, °C	CO_2 injection rate, t/d
Impact of permeability heterogeneity	Oldenburg et al. (2001); Rebscher and Oldenburg (2005)	TOUGH2	6.6 km × 1 km × 100 m	ϕ: 0.35 k_x: 1000 k_z: 10	P: 12 T: 65	708.48
	Ennis-King et al. (2011)	TOUGH2	/	/	P: 19.59 T: 85	95.48
	Feather and Archer (2010)	ECLIPSE	1524 m × 1524 m × 30.48 m	ϕ: 0.2 k_x: 100 k_z: 1–10	P: 3.8–31 T: 100	56.55 –1130.97
Impact of connate water or the injected water	Kalra and Wu (2014)	CMG-GEM	2.286 km × 22.86 m × 91.5 m	ϕ: 0.2 k: 100	P: 30 T: 93.3	56.55
	Patel et al. (2017)	COMSOL	201.19 m × 201.19 m × 45.72 m	ϕ: 0.23 k_x: 5–100 k_z: 0.5–10	P: 9.1 T: 75	27.56
Impact of CO_2 injection timing	Clemens and Wit (2002)	/	4 km × 2 km × 60 m	k: 1.4–55	P: 27.2 T: 100	1205–1644
	Jikich et al. (2003)	UTCOMP	804.67 m × 804.67 m × 3.96 m	ϕ: 0.11 k: 5.5	P: 7.046 T: 22.2	8–664
Impact of CO_2 injection rate	Seo and Mamora (2005)	/	201.19 m × 201.19 m × 45.72 m 284.5 m × 284.5 m × 91.44 m	ϕ: 0.23 k_x: 50 k_z: 5	P: 20.99 T: 66.7	0.127 –0.254
Arrangement of CO_2 injection well and natural gas production well	Oldenburg and Benson (2002)	TOUGH2	6.6 km × 1 km × 100 m	ϕ: 0.35 k_x: 1000 k_z: 10	P: 12 T: 65	708.48
	Hou et al. (2012)	TOUGH2/ FLAC3D	20 km × 100 m × 3 km	ϕ: 0.0928 –0.0935 k: 1200 –1400	P: 13 T: 53	31500
	Luo et al. (2013)	FLUENT	201.19 m × 201.19 m × 45.72 m	ϕ: 0.23 k_x: 5–100 k_z: 0.5–10	P: 3.35 T: 75	8.64

Note: "/" in the table denotes absence of data.

CH_4 recovery to inject CO_2 into the reservoir in a high injection rate at a late stage of gas field life.

The arrangements of CO_2 injection well and natural gas production well are two critical factors of injection strategy in CSEGR implementation. As for vertical wells, the simulation results of both Oldenburg et al. (2002) and Hou et al. (2012) showed that increasing the distance between CO_2 injection wells and natural gas production wells can increase gas production before CO_2 breakthrough. Luo et al. (2013) analyzed the effect of injection/production well perforation placement by conducting CSEGR simulations in a stratified reservoir model with different vertical permeability heterogeneity. The simulation results illustrated both the injection and production perforations placed in the lowest permeability layer can achieve the best CO_2 storage capacity.

The previous simulations revealed that the preferential flow pathway of CO_2 breakthrough was easy to form in the heterogeneous reservoir formation, which is harmful to natural gas recovery. The connate water or injected water was confirmed to weaken the preferential CO_2 breakthrough to stabilize the displacement. The effects of CO_2 injection parameters and well placement on CSEGR were preliminarily analyzed in some previous simulations. However, more simulations on the effect of reservoir heterogeneity, CO_2 injection parameters, and well placements are still needed to achieve better performance of enhancing gas recovery and CO_2 storage before commercial applications of CSEGR.

4.3. Study on optimization of CO_2 injection strategies

The optimization of CO_2 injection strategies plays a decisive role in obtaining the largest storage capacity of CO_2 and enhanced gas recovery in CSEGR. Thus, researchers conducted some simulations on single or coupled optimization of CSEGR, which are mainly presented in Table 5.

To find the optimal injection strategies for CO_2 geological storage and utilization, Genetic Algorithms (GA) has already become one of the most attractive and promising optimization methods with its rapid development and good reliability. GA was respectively employed for CO_2 sequestration in aquifer (Zhang and Agarwal, 2013) and CO_2 geological utilization for enhanced recoveries of water (Liu et al., 2016), oil (Safi et al., 2016), natural gas (Biagi et al., 2016; Liu et al., 2021) and shale gas (Liu et al., 2017). Biagi et al. (2016) employed the integration of TOUGH2 and GA to optimize the injection rate for obtaining the best recovery of natural gas of CSEGR. The optimized constant injection rate of CO_2 can improve the recovery factor by approximately 5%. The optimization of time-dependent CO_2 injection scenarios (constant pressure injection) can achieve higher production rates of natural gas without compromising the reservoir's structural integrity. Zangeneh et al. (2013) confirmed that parameters like CO_2 injection rates, injected compositions well placements, and natural gas production rates are crucial to the objective function by employing the GA optimizer in the CSEGR simulation based on a real gas field in the south of Iran, and the injection rate of CO_2 should be lower than the production rate of natural gas to prevent extra mixing of residual natural gas and injected CO_2. Liu et al. (2021) optimized the CO_2 injection rates and well placements for CSEGR by employing the GA. The results indicated that the horizontal injection well with appropriate length and optimal injection rate can achieve the best gas recovery factor and CO_2 storage. However, the high drilling cost of the horizontal well caused the above injection strategy with horizontal injection well not to be the best economically. Reusing a vertical production well with two suitably placed perforations for

Table 5
Main simulation studies of CSEGR on optimization of CO_2 injection strategies.

Optimization target	Studies	Simulator	Model size $x \times y \times z$	Porosity ϕ Permeability k, mD	Pressure P, MPa Temperature T, °C	CO_2 injection rate, t/d
CO_2 injection rate	Biagi et al. (2016)	TOUGH2, Genetic Algorithm	201.19 m × 201.19 m × 45.72 m	ϕ: 0.23 k_x: 50 k_z: 5	P: 3.55 T: 66.7	8.64–43.2
CO_2 Injection rate	Zangeneh et al. (2013)	/	3.8 km × 3.9 km × 150 m	ϕ: 0.0981 k_x: 2.426 k_z: 1.812	P: 21.01 T: 74	79.88–1278.08
CO_2 injection rates and well placements	Liu et al. (2021)	TOUGH2, Genetic Algorithm	201.19 m × 201.19 m × 45.72 m	ϕ: 0.23 k_x: 50 k_z: 5	P: 3.55 T: 66.7	6.72–8.64

Note: "/" in the table denotes absence of data.

CO_2 injection with an optimized injection rate is economically superior due to reducing the drilling costs.

The optimization of CO_2 injection strategies in CSEGR can promote the enhancement of natural gas recovery, which has been confirmed by the previous simulations. However, the optimization work of CO_2 injection strategies is relatively limited, especially lacking the optimization simulations with considering the comprehensive effect of natural gas recovery and CO_2 storage in CSEGR.

Fig. 5 shows that the temperature range of simulation studies covers from 22 to 150 °C, and is mainly in the range of 50–100 °C. The pressure is situated in the range of 3–42.4 MPa and is largely below 30 MPa. A positive correlation between temperature and pressure is apparent as shown Fig. 5. The relationship of temperature and pressure in the previous simulation studies is consistent with the change with reservoir depth, and a deeper reservoir generally has a higher temperature and a larger pressure. Many simulations described above verified that the depleted gas reservoir is more favorable to inject CO_2 for enhanced gas recovery compared to the gas reservoir at relatively high pressure. Therefore, CO_2-EGR simulations under low pressures seem more meaningful.

In addition, Cui et al. (2021, 2020) proposed the exploitation of geothermal in a depleted high-temperature gas reservoir. Ezekiel et al. (2020) combined CO_2 enhanced natural gas recovery and geothermal energy extraction for electric power generation. Therefore, the CO_2-EGR simulations in gas reservoirs under high temperature and low pressure for enhanced gas recovery combined with the exploitation of geothermal will be more interesting and have scientific significance.

As shown in Fig. 6, the horizontal reservoir permeability of the previous CO_2-EGR simulation studies covers a wide range from 0.1 mD to 10^4 mD while the vertical permeability is usually 10 times lower than the horizontal one. Due to the difference in reservoir model sizes in previous CO_2-EGR simulations, the CO_2 injection rate varied and was up to 5000 t/d.

5. CSEGR research and demonstration projects

A few CSEGR research and demonstration projects have been conducted, and we summarized them in Table 6.

5.1. CSEGR research projects

The CASTOR (Polak and Grimstad, 2009) was an Austria CSEGR research project for Atzbach-Schwanenstadt Gas Field to sequestrate CO_2 with enhanced gas recovery. Simulation results (Polak and Grimstad, 2009) showed that 8.2 × 10^6 t of CO_2 could be stored during 30 years of injection. However, it is confirmed that CO_2 injection has no significant EGR effect due to the quick breakthrough of CO_2 contaminating residual natural gas. The study of CO_2 storage safety indicated that only 5.6% of injected CO_2 might escape through abandoned wells for 1500 years.

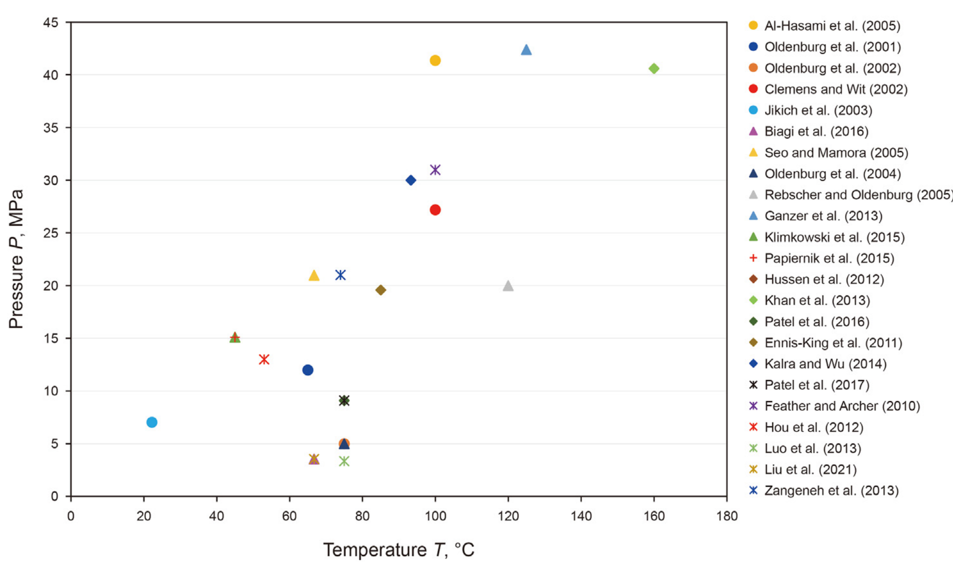

Fig. 5. The temperature and pressure ranges of the simulation studies for CSEGR.

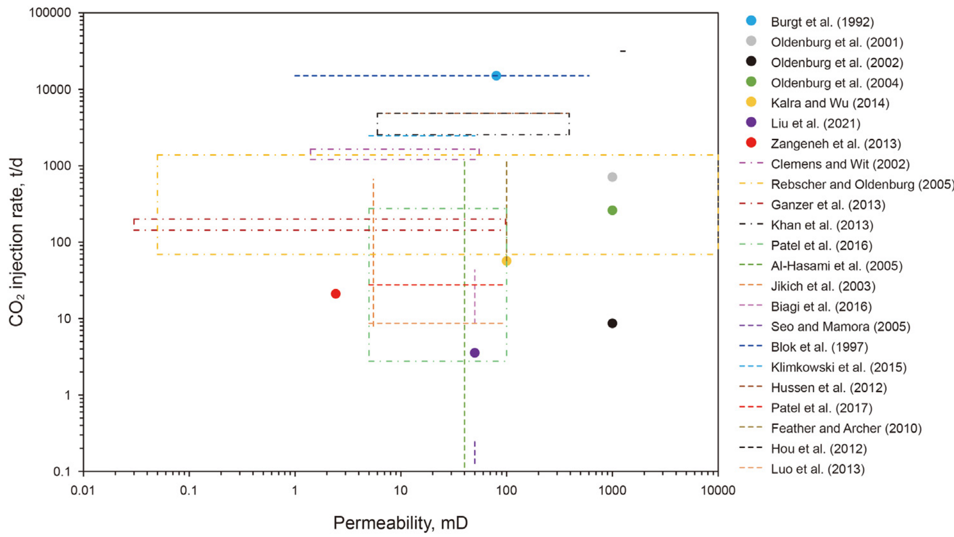

Fig. 6. The horizontal permeability of the gas reservoirs and CO_2 injection rate in the previous simulation studies of CSEGR.

Table 6
The research and demonstration projects of CSEGR.

Project name	Location	Project period	Porosity ϕ Permeability k, mD	Site size	Pressure P, MPa Temperature T, °C	CO_2 injection amount, Mt
Research Projects						
CASTOR (Polak and Grimstad, 2009)	Atzbach-Schwanenstadt Gas Field, Austria	30 years	ϕ: 0.01–0.2 k: 0.01–200	12 km × 7.5 km × 300 m	P: 1 T:/	8.2
CLEAN (Kühn et al. 2011, 2012, 2013)	Altmark Natural Gas Field, Germany	2008–2011	/	14 km^2	P: 3.0–5.0 T:125	0.1
ROAD CCS (Arts et al., 2012; Mikunda and Dixon, 2017)	Offshore P18-4 field, North Sea, Dutch	10 years	ϕ: 0.05–0.12 k: 0.1–200	/	P: 2 T:/	8
Demonstration Projects						
K12–B Gas Field Project (Audigane et al., 2008; van der Meer et al., 2005, 2006, 2013; Vandeweijer et al., 2011, 2018)	North Sea, Dutch	2004–2017	k: 5–500	/	P: 4 T: 132	0.1
Long Coulee Glauconite F Pool (Pooladi-Darvish et al., 2008)	Alberta, Canada	2002–2006	ϕ: 0.12–0.22 k: 10–100	/	P: 0.8 T: 26–110	/
CO_2CRC Otway Project (Jenkins et al., 2012; Underschultz et al., 2011)	Australia	2007–2021	ϕ: 0.138 k: 1105	/	P: 19.59 T: 85	0.095

Note: "/" in the table denotes absence of data.

The joint research project CLEAN (CO_2 Large-Scale Enhanced Gas Recovery in the Altmark Natural Gas Field) (Kühn et al., 2011, 2012, 2013) was conducted for the almost depleted Altmark Natural Gas Field in Germany, and it is one of the good demonstrations of CSEGR. The Altensalzwedel block, a separate subfield of the Altmark Natural Gas Field, was chosen as the research site for CSEGR. Although the demonstration was not permitted to inject CO_2 into the Altensalzwedel section of the gas reservoir due to permitting issues, the research led to a comprehensive evaluation of EGR potential. The simulation confirmed that the Altensalzwedel Subfield is feasible to store CO_2 with a capacity of up to 1.0×10^5 t.

The ROAD CCS is another research project of CSEGR. The offshore P18-4 field (Arts et al., 2012; Mikunda and Dixon, 2017) for CO_2 storage was originally part of the ROAD CCS project, and the field is in the Dutch North Sea. P18-4 field was a near-depleted gas field at a depth of 3500 m under the seabed, and the reservoir pressure was reduced from 35 MPa to 2 MPa during gas production. The evaluated CO_2 storage capacity is up to approximately 8×10^6 t. The assessment showed that the injection rates can be up to 1.5×10^6 t/year without leading to any problems. However, the ROAD project has been severely delayed due to the steep drop of CO_2 emitting price (a detrimental effect on low carbon investments).

5.2. CSEGR demonstration projects

The K12–B (Arts et al., 2008; Audigane et al., 2007, 2008; Kreft et al., 2006; van der Meer et al., 2005, 2006, 2013; Vandeweijer et al., 2011, 2018, 2021) is the first and so-far one of the most famous demonstration projects for both CO_2 storage and enhanced gas recovery by re-injecting the separated CO_2 back into the depleted gas field. The Offshore Re-injection of CO_2 (ORC) project at the K–12B gas field is in the Dutch sector of the North Sea, 150 km northwest of Amsterdam. The K12–B offshore gas field has been producing natural gas since 1987, and the produced gas from the Rotliegend reservoir has a relatively high CO_2 content (13%). The separated CO_2 stream from the produced gas has a purity of 95% with some remaining CH_4, and all these have been re-injected into the sandstone reservoir with a depth of some 3800 m at the temperature of 128 °C since 2004. At the beginning, a fraction of separated CO_2 was injected into the nearly depleted gas field, followed by the injection of all the separated CO_2. With the latest report of Vandeweijer et al. (2018, 2021), the separated CO_2 has been continuously re-injected into the depleted gas fields for another 13 years with the CO_2 mass of 1.0×10^5 t.

The main objectives of the ORC project at the K–12B gas field were to i) examine the injection facility; ii) prove the feasibility and safety of CO_2 injection; iii) investigate the CO_2 phase behavior and reservoir response; iv) assess the potential of enhanced gas recovery; v) examine the degree of tubing corrosion. These objectives were accomplished according to the latest report (Vandeweijer et al., 2021). The ORC project at K12–B gas field verified that the geological storage of CO_2 in depleted gas reservoirs with enhancing natural gas recovery is feasible. The K12–B provides important guidance in testing many techniques and assessments of other CCS projects, such as P18.

The injection of CO_2 into the depleted Long Coulee Glauconite F Pool was another typical CSEGR project (Pooladi-Darvish et al., 2008). The Long Coulee Glauconite F Pool had produced natural gas since 1967 and oil since 1984 from the Upper Mannville Glauconite zone in southeastern Alberta, Canada. The produced gas contains approximately 12% CO_2 and 0.3% H_2S. The separated impure CO_2 (containing less than 2% H_2S) had been re-injected into the reservoir since February 2002 when the reservoir was depleted with the pressure declined from approximately 13 MPa to below 1 MPa. The breakthrough of CO_2 was observed between 2003 and 2005 in three gas-producing wells. The simulation results of Pooladi-Darvish et al. (2008) indicated that the injected acid gas occupies a large reservoir volume of the Long Coulee Glauconite F Pool at low pressures and exhibits limited density difference with the remaining in-situ natural gas, causing the rapid spread of CO_2 and early breakthrough. Simultaneously, it is confirmed that the preferential solubility of H_2S in the reservoir brine led to its preferential stripping from the gas front and delayed its breakthrough compared to pure CO_2.

The CO_2CRC Otway Project (Jenkins et al., 2012; Underschultz et al., 2011) is the heavily monitored demonstration pilot of CO_2 storage in a depleted gas field, located in the Otway Basin of Victoria, southeast Australia. The depleted Naylor Gas Field was the storage site. 65445 t of CO_2-rich gas (75% ± 2% CO_2, 21% ± 2% CH_4, and other heavier hydrocarbons) produced from the nearby Buttress Field was re-injected into the depleted Naylor Gas Field from March 18, 2008 to August 29, 2009. The monitor of the CO_2CRC project demonstrated that no tracer compounds have been detected in the samples taken from the atmosphere, soil gas, and shallow groundwater. Thus, it is confirmed that CO_2 storage in depleted gas fields can be safe and effective, and the CO_2CRC Otway Project provided an understanding of the underlying science of CO_2 storage in a depleted gas reservoir.

The above-described research and demonstration projects are very meaningful for pushing the development of the CSEGR technology. The field knowledge and experience of CSEGR gained from these projects, especially from the Offshore Re-injection of CO_2 (ORC) project at the K–12B gas field, make a significant contribution to paving the foundation of commercial application. The implementation of more such projects will facilitate commercial application.

6. Conclusions and recommendations

This work reviewed the closely related research on CSEGR from laboratory to field scales, including experiments, simulations, research and demonstration projects. The main conclusions can be drawn as follows:

- The large difference between CO_2 and CH_4 in physical properties, including density and viscosity, are theoretical foundation of CSEGR. The dense supercritical CO_2 tends to sink to reservoir bottoms and favors sweep.
- The behavior of CO_2 displacing natural gas play a key role in CSEGR. Visualization studies confirmed the existence of mixing transition zones during CO_2 displacing natural gas. Experimental studies of dispersion coefficient in the CO_2–CH_4 displacement reveal the impact mechanism of various influential factors (such as temperature, pressure, impurity compositions, irreducible water, etc.) on mixing characteristics.
- Simulation studies preliminarily demonstrated that CSEGR is technically and economically feasible for developing depleted gas reservoir. Heterogeneity was showed to cause preferential flow pathway for CO_2 breakthrough. Connate or injected water may weaken this effect and stabilize the displacement. CO_2 injection strategies largely influence the performance of both gas recovery and CO_2 storage.
- K12–B pilot project, located in the North Sea of Dutch, is the most successful demonstration project of CSEGR. K12–B has continuously injected 1.0×10^5 t of CO_2 captured from the produced gas across more than 13 years while enhancing natural gas production. The pilot provides very meaningful guidance for future CSEGR projects.

Although many studies were conducted on CSEGR in both experiments and simulations, there are still some knowledge gaps. Here we recommend some future research directions:

- Dispersion studies considering the complex condition of a gas reservoir, such as connate/influx water and heterogeneity, are still scarce. More studies are needed to accurately measure dispersion, understand mixing characteristics, and incorporate them in reservoir simulation.
- The optimization of CO_2 injection strategies plays a key role in a specific application of CSEGR, which is at the early stage of research. More relevant optimizations with the incorporation of complex reservoir conditions need to be further studied.
- CSEGR employed in high-temperature gas reservoirs can simultaneously develop geothermal energy. CSEGR integrated with geothermal exploitation in these reservoirs seems promising and merits further study.

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