Preliminary study on the CO₂ injectivity and storage capacity of low-permeability saline aquifers at Chenjiacun site in the Ordos Basin

Jian Xie^{a,b}, Keni Zhang^{b,*}, Cai Li^c, Yongsheng Wang^d

^a*College of Environment and Civil Engineering, Chengdu University of Technology, Chengdu 610059, China*

^b*College of Water Sciences, Beijing Normal University, Beijing 100875, China*

^c*China Institute of Geo-Environmental Monitoring, Beijing 100081, China*

^d*China Shenhua Coal Liquefaction Co. Ltd. (CSCLC) Ordos, Ordos 017209, China*

Abstract: Deep saline aquifers are a promising choice for geological carbon dioxide (CO₂) sequestration due to their greater storage capacity compared to other geological storage options. Injectivity and storage capacity are key concerns especially considering injection of CO₂ into low-permeability reservoirs. Estimation of the CO₂ injectivity and storage capacity was conducted with an analytical method and dynamic numerical modeling for an active demonstration site (Chenjiacun) of CO₂ sequestration in the Ordos Basin. The analytical estimate of the mass injectivity of the Liujiagou reservoir is $4.06 \times 10^{-6} \text{ kg} \cdot \text{Pa}^{-1} \cdot \text{s}^{-1}$, which is about 64% of the injectivity of the entire reservoir system, followed by the Shiqianfeng unit, which accounts for some 15.8%. The maximum injection rate for the Liujiagou reservoir was estimated to be roughly $15.1 \text{ kg} \cdot \text{s}^{-1}$, leading to 476,000 tonnes of CO₂ injected per year. The maximum injection rates for the other four reservoirs are substantially smaller than that for the Liujiagou reservoir. The injectivity of the Liujiagou reservoir estimated by numerical simulation ranges from 0.7 to $3.0 \times 10^{-6} \text{ kg} \cdot \text{Pa}^{-1} \cdot \text{s}^{-1}$. The injectivity of the Shiqianfeng reservoir was estimated to be from 0.2 to $1.1 \times 10^{-6} \text{ kg} \cdot \text{Pa}^{-1} \cdot \text{s}^{-1}$. The injectivities of the remaining reservoirs (i.e., Shihezi downward) are smaller than $0.6 \times 10^{-6} \text{ kg} \cdot \text{Pa}^{-1} \cdot \text{s}^{-1}$. The maximum injection rate estimated from the numerical simulation is approximately $17 \text{ kg} \cdot \text{s}^{-1}$, leading to 536,000 tonnes storage of CO₂, with the injection pressure limited to 1.5 times hydrostatic pressure. The annual CO₂ storage capacity of the Chenjiacun site is estimated to be 0.53~0.69 Mt, for a single vertical injection well. About 5 injection wells may be required to deal with the current CO₂ emission rate from CSCLC coal liquefaction processes, which is about 3 Mt per year.

The injectivity and storage capacity at Chenjiacun are not much smaller than that at In Salah and Ketzin, owing to the relatively great thickness and long perforated interval at Chenjiacun. In order to improve the reservoir injectivity and storage capacity further at Chenjiacun for large-scale CO₂ storage in the future, possible injection strategies and reservoir management options include introduction of stimulation measures and water-production wells at approximately 1000 m or even further away from the injection well, as well as using fully penetrating vertical wells with long perforated intervals.

Keywords: Ordos; CCS; geological CO₂ storage; saline aquifer; injectivity; storage

*Corresponding author.

E-mail address: keniz@bnu.edu.cn (K. Zhang).

capacity

1. Introduction

Deep saline aquifers are generally considered the most promising reservoirs for geological carbon dioxide (CO₂) sequestration compared to other geological storage options such as oil and gas reservoirs (Eccles et al., 2009; IPCC, 2005; US-DOE, 2007). Several well-known geological CO₂ sequestration projects have been implemented internationally. Sleipner in Norway is the first and also the longest running Carbon Capture and Storage (CCS) site in the world. Weyburn in Canada is the largest land-based CO₂ storage site in the world, and operates in conjunction with Enhancement Oil Recovery (EOR) with horizontal drilling technology. Compared to the extremely favorable reservoir conditions encountered at Sleipner, In Salah in Algeria is an onshore CO₂ storage project in a low porosity/permeability formation. CO₂ storage at these three sites is of commercial scale or at least demonstration scale (Michael et al., 2010). By contrast, Ketzin in Germany is the first European onshore storage site for pilot-scale CO₂ injection research (Martens et al., 2011). These project sites have boosted science and technology in the field of CCS markedly.

The study of CCS is still in its exploration phase in China. So far, no comprehensive experience has been gained on subsurface storage of CO₂ due to a lack of operational CCS projects. In 2010, the China Shenhua Coal Liquefaction Co. Ltd. (CSCLC), as the field operator, launched the first CCS program in the low-permeability (<10 mD) formations of the Ordos Basin. It has been generally proposed that selection of a geological sequestration site be targeted to reservoirs with relatively high permeability and porosity, because it is more likely that CO₂ can be successfully injected into such formations. However, such formations are not always available in areas where CO₂ sources are located. Therefore, low-permeability saline aquifers are increasingly considered when planning CCS projects in such areas. Low-permeability aquifers may not be as disadvantageous as we have supposed in some cases (Eigestad et al., 2009). From a storage point of view, formations with high permeability are favorable due to great injectivity. However, due to spreading of the CO₂ plume over larger areas, there is an increased risk of CO₂ intersecting more permeable geologic features such as faults where leakage into shallow formations could occur.

The qualification of a reservoir candidate for geological CO₂ sequestration can be summarized by the four following requirements, namely (1) favorable burial depth (800+ m bgs, i.e., below ground surface) to ensure the injected CO₂ is supercritical; (2) relatively continuous and thick sealing formations to prevent CO₂ from escaping out of the reservoir; (3) sufficient available pore space to store a prescribed amount of CO₂; and (4) favorable permeability to facilitate pressure propagation. The last two qualifications are closely related to storage capacity and injectivity, both of which are key issues of concern when speaking of large-scale storage.

Injectivity characterizes the ease with which fluid can be injected into a geological formation. It is a major determinant of the suitability of a site for carbon dioxide

storage. It is defined as the injection rate divided by the difference between the injection pressure and the formation pressure (Benson and Cook, 2005). The maximum injection rate is the largest injection rate that can be attained under the highest allowable injection pressure (Ghaderi et al. 2009; Lucier and Zoback, 2008). Many reservoir parameters directly or indirectly affect injectivity, including permeability, porosity, reservoir thickness, areal extent, pressure, temperature, brine salinity and relative permeability (Mathias et al., 2011; Mathias et al., 2013). For an open saline aquifer, the injectivity is largely dependent on the effective permeability of CO₂ to the formation brine, geologic architecture, and aquifer heterogeneity. As CO₂ is introduced at a constant injection pressure, the CO₂ injection rate increases, owing to an increase in bulk mobility associated with the lower viscosity of CO₂ relative to brine. The main controls on this change in mobility are the relative permeability parameters and CO₂ and water viscosities, which are a function of temperature. For a closed saline aquifer, however, the injectivity is more related to the absolute permeability of the formation and the bulk compressibility of the reservoir fluid and formation (Mathias et al., 2013). If CO₂ is injected into a closed reservoir with injection pressure kept constant, the injection rate will decrease with time. Storage capacity is the mass of CO₂ that can be injected into a reservoir before the CO₂ plume reaches a spill point and leakage occurs (Kopp et al., 2009). The USGS defines CO₂ storage capacity as the technically accessible storage resource, i.e., the quantity of CO₂ that can be commercially stored by available technology from a given date forward under defined conditions; it includes economic, regulatory, and legal constraints (Goodman et al., 2013). There are numerous parameters that affect the carbon dioxide storage capacity in deep saline aquifers. These parameters are related to the reservoir geometry (area and thickness), physical and geochemical properties (e.g. permeability, porosity, compressibility, etc.), fluid thermodynamic properties or state variables (e.g. salinity, diffusivity, temperature, and compressibility), boundary conditions, trapping mechanisms, allowable plume migration limit, limitations on the injection rate due to pressure constraint, formation stress and geomechanical properties, injectivity and duration of injection, and integrity of cap rocks (De Silva and Ranjith, 2012). Efficient utilization of CO₂ storage space will depend on all these factors.

The Ordos Basin has been identified as one of nine inland basins in China that are potentially favorable places for geological storage of CO₂, due to its widespread, deep and thick saline aquifers. However, the formations in this basin are characterized by low/extremely-low permeability. The injectivity and pressure buildup associated with injection were therefore primary concerns at the beginning of the Shenhua CCS project. Unexpectedly, the injection operation at the Chenjiacun site (described in the next section) turned out to be quite successful. The Triassic Liujiagou Sandstone unit has surprisingly great injectivity. The wellhead injection pressure dropped from around 7 MPa at the beginning to less than 5 MPa at present and no large pressure buildup has been observed at the site. These phenomena have increased the interest of the Chinese CCS community.

It is necessary to evaluate the CO₂ injectivity and storage capacity of the reservoirs at

the Chenjiacun storage site in the Ordos Basin, to gain insights for large-scale CO₂ sequestration in the future. Large-scale geological CO₂ sequestration is of increasing interest at this site, because since 2009 coal liquefaction at CSCLC leads to a potential release of 3 million tonnes of CO₂ per year. This work presents the preliminary evaluation of the reservoir performance in terms of injectivity, the maximum injection rate, and storage capacity. Site-specific data were used for this study in order to characterize the reservoir.

2. Site characteristics

2.1. Shenhua CCS project

The Shenhua CCS project is the first public demonstration project in China, where CO₂ captured from coal liquefaction processes was sequestered in deep (>1576 m) saline aquifers (Best and Beck, 2011; Wu et al., 2013). The injection site (110.17°E, 39.33°N, 1330 masl) of the Shenhua CCS project is geographically situated in the Chenjiacun village of Wulam Len town, EjinHoro county, about 40 km southeast of Ordos City (Fig. 1a and 1b). The project has injected the designed injection amount of 3.0×10⁵ tonnes of CO₂ by the end of April, 2015. There are one single vertical injection well (INJW) and two monitoring wells (MW1 and MW2) at the site, with MW1 located 70 m to the west of INJW for pressure and temperature surveillance, and MW2 located 30 m to the north for regular water sampling and vertical seismic profiling (VSP) to judge if CO₂ breakthrough has occurred (Fig. 1c). The injection well was perforated over five brine-bearing geological units situated at 1576- 2453 m bgs. CO₂ was injected at a variable injection rate, depending on the recorded well-head injection pressure. A more detailed introduction to this project is found in Xie et al. (2015a,b) and Li et al. (2016).

2.2. Reservoir description

The strata at the site are typical of the Ordos Basin, composed of alternating mudstones and low-permeability fluvial sandstones from the late Carboniferous through the early Triassic, as well as Ordovician limestones at the bottom (Fig. 2). From top to bottom, the formation units are named Zhidan (C1), Anding (J2), Zhiluo (J2), Yan'an (J1), Yanchang (T3), Zhifang (T2), Heshanggou (T1), Liujiagou (T1), Shiqianfeng (P3), Shihezi (P2), Shanxi (P1), Taiyuan/Benxi (P1/C2), and Majiagou (O1). For the sake of convenience, in this study we refer to them in sequence as ZHD, AND, ZHL, YAN, YCH, ZHF, HSG, LJG, SQF, SHZ, SHX, TYN/BXI, and MJG. Injection was targeted to the reservoirs from LJG down to MJG, and the injection well was perforated accordingly (Fig. 2). The reservoir above a depth of 2367.4 m is dominantly fine-grained and mud-bearing fluvial sand or silt, with permeability ranging from 0.02 to 39 mD and porosity ranging from 2.5 – 12.9%. The lower reservoir is comparatively dense carbonate (limestone), with porosity 1.7 – 5.6% and

permeability approximately 0.32 mD. The porosity and permeability of the topmost storage reservoir selected for CO₂ sequestration (the Lower-Triassic LJG Sandstone) at Chenjiacun averages around 11.4% and 10.6 mD, respectively. The reservoir formation slightly dips toward the northwest with a dip angle less than 2 degrees. More information about the geology of the area is found in various resources (Jiao et al., 2011; Li et al., 2013; Wu et al., 2013).

Fig.1. Geographic location of the Chenjiacun site in the Ordos Basin (a-b), and the relative location of the monitoring wells (MW1 and MW2) to the injection well INJW (c).

Fig.2. Schematic diagram of the strata sequence and the injection well (INJW), illustrating the location of injection layers, pressure (P) and temperature (T) monitoring and water sampling. The well sections shown with a dashed line indicate the perforated intervals. The horizontal dotted lines suggest the formation boundaries.

3. Data and approach

3.1. Injectivity and the maximum injection rate

According to the definition of injectivity, the volumetric and mass injectivity of supercritical CO₂ for an undamaged well under unsteady state can be formulated as follows by applying the Darcy's law, based on the assumption that well skin effects are negligible and water saturation achieves irreducible water saturation in the vicinity of the injection well so that gas relative permeability is unity:

$$J_v = \frac{q}{\Delta P} = \frac{2\pi kh}{\mu \ln(0.472r_e/r_w)} \quad (1)$$

$$J_m = J_v \cdot \rho \quad (2)$$

Where J_v -volumetric injectivity; J_m -mass injectivity; q -volumetric flow rate at the bottom of the injection well; ΔP -pressure difference between the bottom of the injection well and the formation; k -formation permeability; h -formation thickness; ρ , μ -density and viscosity of injected fluid (CO₂) at the bottom hole pressure and

temperature; r_e and r_w are equivalent closed formation radius and wellbore radius, respectively. This equation is also presented in Xie and Economides (2009).

The maximum injection rate is the largest injection rate that can be attained under the highest allowable injection pressure (Ghaderi et al., 2009; Lucier and Zoback, 2008).

Therefore, the maximum injection rate can be calculated as follows:

$$q_{\max} = J_m \cdot (P_m - P) \quad (3)$$

where $q_{\max}$ is the maximum injection rate, and P_m and P are the allowable highest downhole injection pressure and the pressure in the formation near the injection well, respectively.

3.2. Storage capacity

There are a variety of approaches and methodologies to assess CO₂ storage capacity. Worldwide CO₂ storage estimates are primarily based on either CSLF or US-DOE methods. The approach by US-DOE (2012) is a straightforward method for calculation of storage capacity in open saline aquifers.

$$M_c = A \times H_g \times \phi \times \rho \times E \quad (4)$$

Where M_c is the estimated CO₂ storage capacity, A , H_g , and ϕ are area, average gross thickness, and porosity of the aquifer, respectively, gross thickness is the average thickness of the saline formation for storage of CO₂ in a defined area, ρ is the average CO₂ density under representative reservoir conditions, and E is the storage efficiency accounting for total pore volume filled with CO₂. It can be calculated as the volume of injected CO₂ divided by the total pore volume (Williams et al., 2013).

CSLF: Bachu et al. (2007) proposed the classical framework for CO₂ storage capacity classification. It defines a number of terms in a 'pyramid' way, namely theoretical (storage) capacity, effective (storage) capacity, practical (storage) capacity, and matched (storage) capacity, each of which is a subset of the former. The theoretical storage capacity assumes that the entire pore volume of a formation except that occupied by liquid phase via the irreducible saturation is accessible to store CO₂. The effective storage capacity considers only those parts of theoretical capacity that are both geologically and technically feasible. The practical capacity is a subset of the effective capacity and considers furthermore economic, legal and regulatory, infrastructure and general economic aspects. Finally, the matched capacity is a result of detailed matching of large stationary CO₂ sources with adequate geological storage sites.

According to Bachu et al. (2007), the effective storage capacity $V_{CO_2,e}$ [m³] can be calculated by the theoretical capacity $V_{CO_2,t}$ [m³] multiplied by the capacity coefficient C_c [-].

$$V_{CO_2,e} = C_c V_{CO_2,t}, \quad C_c \in \{0,1\}, \quad (5)$$

$$\text{where } V_{CO_2,t} = \phi(1 - S_{w,i})V_{\text{form}}, \quad (6)$$

With ϕ and $S_{w,i}$ here denoting equivalent average porosity and the irreducible liquid saturation of the reservoir, respectively. V_{form} is the total geometric reservoir volume (bulk volume). C_c is a capacity coefficient that incorporates the cumulative effects of

reservoir heterogeneity, CO₂ buoyancy and sweep efficiency.

Doughty et al. (2001) derived a formula to calculate the effective capacity coefficient C [-]:

$$C = C_i C_g C_h \phi, \quad C \in \{0, \phi\}, \quad (7)$$

where C_i is the intrinsic capacity coefficient [-], C_g is the geometric capacity coefficient [-] and C_h is the heterogeneity capacity coefficient [-]. Detailed explanation of the underlying significance of these coefficients has been given by Doughty et al. (2001) and Kopp et al. (2009) and hence is not presented herein. The C_i can be approximated by Eq. (8) according to Doughty et al. (2001).

$$C_i = S_g + S_w X_{\text{CO}_2, \text{aq}} \frac{\rho_w}{\rho_g} \quad (8)$$

where S_g and S_w are the average gas and liquid saturations, respectively, $X_{\text{CO}_2, \text{aq}}$ is the average mass fraction of dissolved carbon dioxide in the formation brine [kg/kg], and ρ_w and ρ_g are the mass density [kg/m³] of the liquid and gas phase, respectively.

With Eq. (5) – (8), the mass of the effective storage capacity $M_{\text{CO}_2, e}$ [kg] can therefore be estimated as follows:

$$M_{\text{CO}_2, e} = \rho_{\text{CO}_2} C V_{\text{form}} \quad (9)$$

where the lower estimate of the CO₂ density ρ_{CO_2} is calculated by considering initial reservoir pressure conditions and the upper estimate is calculated by considering the lesser of the maximum allowable pressure to avoid rock fracturing and the threshold entry pressure of the caprock.

Zhou et al. (2008) proposed a simple method for quick assessment of CO₂ storage capacity in closed or semi-closed saline formations. The basic idea underlying this method is that the injected CO₂ is retained in the reservoir via the expansion of pore space due to compressibility of both rock and fluid. The storage capacity for CO₂ mass for the closed systems (M_{CO_2}) is therefore estimated by Eq. (10):

$$M_{\text{CO}_2} = (\beta_p + \beta_w) \Delta P \rho \phi A H_g \quad (10)$$

where β_p and β_w are the pore and brine compressibility, respectively, and ΔP is the sustainable pressure buildup, which refers to the pressure that the storage formation can accommodate without undergoing geo-mechanical damage (Neuzil, 2003). Definition of the other symbols is found in Eq. (4).

3.3. Data collection

The data collected for this study include borehole logging data, 3D seismic data, VSP interpretation, well test data, injection operating data, and observed pressures from the monitoring well MW1. Hydrogeologic parameters such as porosity and permeability were obtained from interpretation of the electrical logging data from the injection well. Injection was performed for more than three years starting in May 2011, although the operational data were only available up to January 2014 (i.e. 2.72 years) at the time of writing. The pressure observation data for this study were available for 9 May 2011 - 18 December 2013.

4. Analytical estimation

4.1. Injectivity

Table 1 shows the volumetric and mass injectivities estimated with Eq. (1) and (2) for the five reservoirs at Chenjiacun injection site. The average reservoir pressure and temperature under injection were estimated from a permanent downhole monitoring system amounted in the injection well. Based on the average pressure and temperature of the reservoir under injection, the CO₂ viscosity was calculated from Fenghour and Wakeham (1998) and the CO₂ density was estimated from Span and Wagner (1996). The permeability (k) presented in Table 1 is the thickness-weighted average permeability of the reservoir which consists of several aquifers and therefore the thickness (h) is the accumulative thickness of the aquifers. The equivalent radius (r_e) was estimated from the numerical simulation (see Section 5.3 below). It can be seen that the injectivity decreases downward from LJG to MJG and thus the largest injectivity is for the LJG reservoir. As indicated in Eq. (1), the injectivity of a formation is mainly dependent on the permeability and thickness of the reservoir. The LJG reservoir has the largest permeability and thickness, and this makes it the primary reservoir for CO₂ sequestration at Chenjiacun site. The mass injectivity of the LJG reservoir is $4.06 \times 10^{-6} \text{ kg} \cdot \text{Pa}^{-1} \cdot \text{s}^{-1}$, which implies an injection rate of $4.06 \text{ kg} \cdot \text{s}^{-1}$ under the condition of 1.0 MPa pressure difference.

Four injection tests were performed at this site in 2013 by injecting CO₂, at a temperature of approximately 0 °C and at a pressure of 5.16 MPa at the surface, down into the storage reservoirs below 1615 m depth. More details about these injection tests have been described in Li et al. (2016) and Zhang et al. (2016). Table 2 presents the injectivity contribution of each reservoir to the Chenjiacun site from these injection tests. It suggests that the LJG reservoir has some 79% of the injectivity of the entire reservoir system, followed by the SQF unit, which accounts for some 12%. The LJG unit acts as the primary storage reservoir of the Chenjiacun site because of its relatively high permeability and great thickness. Our injectivity estimates show satisfactory consistency with these observations from the injection tests.

Table 1 Estimation of injectivity for the reservoirs at Chenjiacun site.

Parameters	LJG	SQF	SHZ	SHX	MJG
P (MPa)	18.61	21.22	22.75	23.17	24.68
T (°C)	48.63	55.45	62.84	64.95	68.67
ρ (kg·m ⁻³)	769.44	765.30	742.34	736.27	738.51
k (mD)	6.58	2.93	2.75	1.73	0.32
h (m)	84.0	45.6	35.4	32.4	31.2
μ (×10 ⁻⁵ Pa S)	6.69	6.64	6.35	6.29	6.33
r _e (m)	6000	5000	4000	3500	2000
r _w (m)	0.15	0.15	0.15	0.15	0.15
J _v (m ³ ·Pa ⁻¹ ·S ⁻¹)	5.27E-09	1.31E-09	1.02E-09	6.02E-10	1.13E-10

$J_m(\text{kg}\cdot\text{Pa}^{-1}\cdot\text{S}^{-1})$	4.06E-06	1.00E-06	7.57E-07	4.43E-07	8.37E-08
Pct. J_m (%)	64.0	15.8	11.9	7.0	1.3

P-weighted average reservoir pressure under injection (estimated from monitoring data);
T-weighted average reservoir temperature (estimated from monitoring data); Pct. J_m -percentage
mass injectivity.

Table 2 Percentages of contribution from each formation (Fm.) unit to the site injectivity during the injection tests.

Fm. units	Test 1	Test 2	Test 3	Test 4	Average
LJG	79.43	81.80	77.30	78.60	79.28
SQF	12.31	10.80	13.80	12.90	12.45
SHZ	4.98	4.00	5.80	3.60	4.60
SHX	0.00	3.40	0.00	0.10	0.88
MJG	3.28	0.00	3.10	4.80	2.79

4.2. The maximum injection rate

Calculation of the maximum injection rate from Eq. (3) requires determination of the highest allowable injection pressure (P_m), which can be estimated as 1.5 times hydrostatic P_0 by convention (Table 3). Therefore, the maximum injection rate for the LJG reservoir should be roughly 15 kg/s, leading to 0.48 million tonnes (Mt) per year. The maximum injection rates for the other four reservoirs are substantially smaller than that for the LJG reservoir (Table 3).

Table 3 The maximum injection rates for the reservoirs at Chenjiacun site.

	LJG	SQF	SHZ	SHX	MJG
Depth (m)	1576-1699	1699-1990	1990-2232	2232-2367	2367-2453
P_0 (MPa)	14.89	17.41	20.14	20.93	22.30
P (MPa)	18.61	21.22	22.75	23.17	24.68
P_m (MPa)	22.33	26.11	30.21	31.39	33.45
J_m ($\text{kg}\cdot\text{Pa}^{-1}\cdot\text{S}^{-1}$)	4.06E-06	1.00E-06	7.57E-07	4.43E-07	8.37E-08
$q_{\max}$ ($\text{kg}\cdot\text{S}^{-1}$)	15.10	4.89	5.65	3.64	0.73
$q_{\max}$ ($\text{Mt}\cdot\text{yr}^{-1}$)	0.476	0.154	0.178	0.115	0.023

*Formula for calculating $q_{\max}$: $q_{\max}=J_m\cdot(P_m-P)$, $P_m=1.5\cdot P_0$; P is the observed pressure under injection in May 2013.

5. Numerical simulation

5.1. Geological model

Dynamic numerical simulations of CO_2 injection into the reservoirs at Chenjiacun were performed with TOUGH2-MP/ECO2N (Pruess, 2005; Zhang et al., 2008) to

evaluate the site performance in terms of injectivity, the maximum injection rate, and storage capacity. The geological model is based on information from log and core data at the site. The model domain has a lateral extent of 12 km by 12 km and an average vertical thickness of 900 m, with the depths ranging from 1547.8 m to 2453.0 m. The HSG (1547.8–1576.0 m) was chosen as the model top (i.e. the first grid-layer of the model) because there is likely a regional confining formation immediately above this reservoir interval. The cumulative thickness of the storage reservoirs is 218.6 m between depths 1547.8 – 2453.0 m, separated by 686.6 m of mudstones at various depths. The reservoir is sandstone/siltstone for the upper 187.4 m of thickness. The lower 31.2 m-thickness of the reservoir is comparatively dense carbonate (limestone). The interbedded mudstones act as barriers for vertical flow. Semi-permeable formations are assumed at depths 1680-1690 m and 1576-1615 m because these depths contain alternating layers and patches of sandstones and mudstones and hence hydraulic communication is possible across these layers. The model has layer-by-layer heterogeneous permeabilities and porosities to examine the impacts of geologic complexity on the plume migration. The sedimentary sequence of formations in the model is shown in Fig. 2.

5.2. Model inputs

Fixed lateral pressure boundaries were assumed because the model domain is extensive enough that the boundaries do not impact our injection modeling. However, the entire system is impermeable at the upper and lower boundaries according to the geologic model. The formation properties such as permeability and porosity were assigned based on interpolation of the 3D seismic interpretation and logging data. The ratio of horizontal to vertical permeability was set to 10 for all the formation rocks due to lack of experimental data.

The initial pressure field was determined by applying a pore pressure regression equation $P=0.1526E08+9991 \times (-Z-1694.50)$ which ensures the adopted initial pore pressure to be 15.26 MPa at 1694.5 m depth, according to the downhole pressure measurements. The initial temperature varies linearly with a geothermal gradient of 26.8 °C/km, from ~49 °C at the model top layer (on average 1547.8~1576.0 m) to ~73 °C at the bottom layer (on average 2451.0~2453.0 m). It is assumed that the formations are initially water-saturated. The reservoir brine has a salinity of 3% (i.e. 30 g salt per kg water) based on water sample analyses. The formations are assumed to be free of gas phase initially. Relative permeabilities and capillary pressures are calculated using van Genuchten-Mualem functions (Mualem, 1976; Van Genuchten, 1980) and van Genuchten functions (Van Genuchten, 1980), respectively. The parameter m in van Genuchten's notation is set to 0.45 due to lack of data. The residual water saturation $S_{w,r}$ is estimated to be 35% - 50%, following the suggestion of the project team in 2014. The residual gas saturation is assumed to be 5% and 10% for the aquifers and caprocks, respectively. Table 4 summarizes the main inputs of the model for the simulations.

Simulations were run under isothermal conditions for 3.65 years of injection followed

by 100 years of post-injection simulation. The model was calibrated to the monitored pressure dynamics, the injectivity contribution for each storage reservoir manifested by the injection tests in Table 2 and the areal distribution of trapped CO₂ derived from the VSP imaging. The base-case simulation is for model calibration and therefore duplicates the actual injection operation at the Chenjiacun site. The mass injection rates of CO₂ specified for the base case have been presented in various publications (Li et al., 2015; Xie et al., 2015b; Zhang et al., 2016) and hence it are not repeated herein. Except for the base case for model calibration, all the simulation cases were run under conditions of constant injection pressure to allow for examining injection rates and estimating injectivity. An estimated maximum safety injection pressure (ac. 24 MPa) was adopted for the simulations, designed for investigating potential factors that could influence the reservoir injectivity and maximum injection rate.

Table 4 Hydrogeologic parameters for the different formation units in the model.

Fm. units	ρ (kg·m ⁻³)	$\emptyset$ (%)	K_h (mD)	C (10 ⁻¹⁰ Pa ⁻¹)	P_0 (KPa)	$S_{w,r}$ (-)	$S_{g,r}$ (-)
SEALS	2600	0.01	1.16E-05	0.95	383.14	0.55	0.10
HSG	2500	0.01	1.16E-05	1.10	11.22	0.55	0.10
LJG1-LJG4	2400-2500	2.5-11.4	0.01-10.60	1.10-6.80	3.27-11.22	0.40-0.50	0.05
SQF1-SQF7	2400-2500	6.1-12.9	0.11-2.96	3.70-6.70	5.08-10.85	0.45-0.50	0.05
SHZ1-SHZ5	2400-2600	8.0-12.6	0.36-2.70	6.38	5.46-10.08	0.45-0.50	0.05
SHX1-SHX3	2500-2600	3.6-11.3	0.01-2.02	1.00-6.53	6.62-11.99	0.50	0.05
MJG	2700	3.5	0.32	9.28	10.46	0.50	0.05
INJW	2600	99.9	200.00	9.50	2.78	0.30	0.01

ρ , rock density; $\emptyset$, layer-average porosity; K_h , layer-average absolute permeabilities in X and Y directions; C , rock compressibility; P_0 , capillary entry pressure; $S_{w,r}$, irreducible water saturation; $S_{g,r}$, residual gas saturation. LJG1-LJG4 indicates there are 4 model layers for the LJG formation unit.

5.3. Model calibration

Three findings from the field observation serve as the major constraints of the model presented herein: (1) the observed pressure dynamics reveal low pressure buildup caused by injection; (2) the LJG reservoir stored around 80% of the injected CO₂ according to the injection tests in 2013, as shown in Table 2; and (3) the CO₂ plume spread radially about 300 m from the injection well in the LJG reservoir after 1 year of injection, according to the VSP results. Pressures were monitored in MW1 at four depths (1690.45 m, 1907.45 m, 2196.43 m, and 2424.26 m) respectively in the LJG, SQF, SHZ and MJG, and at 1631.6 m in INJW. A preliminary effort has been made to calibrate the model-simulated pressures to the observed values from the storage site. Fig.3 illustrates the pressure match for this study. It can be seen that the model overall describes the pressure dynamics correctly, but with some underestimation, particularly for the LJG reservoir. Two reasons could be responsible for this discrepancy. First, a local pressure abnormality was found in the reservoir according to the 3-D seismic

interpretation. This cannot be effectively described by the hydrostatic approximation in our model. Second, for the real case there are four packers **installed** at different depths both within MW1 and INJW. In the present simulation, however, the effects of the packers are not included. The presence of the packers could **possibly** make the monitoring positions overpressurized. We **chose not** to improve the match for pressures because there is a tradeoff between the pressure and other metrics of the match. **For instance, improving the pressure match for the LJJ unit by reducing the permeability of LJJ will lead to a smaller percentage of CO₂ stored in the LJJ and a smaller plume size.** Fig.4 presents the simulated CO₂ plume distribution at the end of injection (i.e. 3.65 years) and Fig.5 compares the distribution of CO₂ mass percentages with the well test results. It is clear that the model captures the essential features of the system quite well. The LJJ unit acts as the primary storage reservoir of the Chenjiacun site since around 80% of the injected CO₂ will eventually enter this formation.

Fig.3. Comparison between the simulated and observed pressures at **a) 1690.5 m in** the LJJ reservoir and **b) 1631.6 m in the INJW.**

Fig.4. CO₂ saturation plume at the end of injection (31 December 2014).

Fig.5. Model simulated mass percentages of injected CO₂ for individual reservoirs in comparison with those from the injection tests.

5.4. Model-estimated injectivity and the maximum injection rate

Fig.6 illustrates the injection rates since injection began, when injection pressure is

kept constant and equals 1.2- and 1.5-times hydrostatic pressure (P_0). It is clearly seen that for both cases the injection rate increases rapidly at early time due to displacement of brine by low-viscosity CO_2 . As time progresses, the injection rate gradually approaches a maximum value. Higher injection pressure results in higher injection rate. With injection pressure $1.2P_0$, the injection rate would be over 6.5 kg/s and the maximum injection rate ($q_{\max}$) would be about 9 kg/s, which lead to 272,590 tonnes per annum. The maximum injection rate is expected to be 17 kg/s, leading to about 536,000 tonnes per annum storage of CO_2 if the injection pressure is increased to $1.5P_0$. The maximum injection rate for the LJG reservoir is approximately 12 kg/s, by simulations with the injection pressure $1.5P_0$. This estimate is lower than the analytical counterpart by about 3 kg/s or 20% (See Table 3). The CO_2 mass accumulation due to injection with different pressures is clearly demonstrated in Fig.7. The injection operation for the Chenjiacun site has been keeping injection pressure around $1.3P_0$, leading to a $0.3P_0$ pressure difference between the injection well and formation. Therefore, our simulation results explain fairly well the injection rates at Chenjiacun.

Fig.8 presents the estimated injectivities by the numerical model for the reservoirs at Chenjiacun. The injectivity of the LJG and SQF reservoir range from 0.7 to $3.0 \times 10^{-6} \text{ kg} \cdot \text{Pa}^{-1} \cdot \text{s}^{-1}$ and from 0.2 to $1.1 \times 10^{-6} \text{ kg} \cdot \text{Pa}^{-1} \cdot \text{s}^{-1}$, respectively. The injectivities of the remaining reservoirs (i.e., SHZ, SHX and MJG) are smaller than $0.6 \times 10^{-6} \text{ kg} \cdot \text{Pa}^{-1} \cdot \text{s}^{-1}$. These injectivity estimates are close to those presented in Table 1. The maximum injection rates estimated by the model are smaller than those determined by the analytical method as shown in Table 3. This is probably due to a combined effect of the comparatively higher injectivity estimated by analytical means, and other complex factors such as inaccurate description of saturation-relative permeability relations for numerical simulations.

Fig.6. Dynamic injection rates of the injection well (INJW) and into the LjG reservoir (LjG) under constant injection pressure 1.2 and 1.5 times hydrostatic pressure (P_0).

Fig.7. Evolution of the cumulative masses of the injected CO₂ for the entire system ('Total') and the LJG reservoir ('LJG') under constant injection pressure 1.2- and 1.5-times hydrostatic pressure (P₀).

Fig.8. Simulated injectivity of the reservoirs at the Chenjiacun site.

5.5. Storage capacity

The predictive flow simulation under a constant injection pressure indicates that injection with a 1.5 times hydrostatic pressure over 3 years **causes** the plume to travel to around 1000 m after 100 years. A radial extent of 1000 m is therefore chosen for the **capacity** estimation calculation since there is a deficiency of site characterization **data** to determine the **lateral** extent of the saline aquifers. The numerical simulation of CO₂ injection is also used to determine the phase densities, mass fraction of CO₂ dissolved in the brine, and to estimate the storage efficiency for application of the US-DOE (2012) method. Calculation of the storage capacities for each reservoir is therefore based on the corresponding average estimates of the saturation (S_{CO2}), density and mass fraction of CO₂ dissolved in the brine (X_{CO2aq}) as shown in Fig. 9. The sustainable pressure buildup for the Zhou et al. (2008) method is determined as

50% of the initial pressure at the top of each formation unit, following the practice of Zhou et al. (2008) and Goodman et al. (2013). It is not easy to individually estimate the geometric and heterogeneity capacity coefficients as termed in Doughty et al. (2001; 2003). For this reason, Doughty et al. (2001; 2003) suggested the product of the geometric and heterogeneity capacity coefficients be taken to be roughly 0.1 for studies for which no numerical simulation has been done. However, it is quite simple to derive this product when a numerical simulation has been done. Technically, it is calculated as the ratio of the number of grid blocks contacted by CO₂ to the total number of grid blocks, over the pre-defined area. Table 5 summarizes the values of the parameters applied to estimate storage capacities for each reservoir unit at Chenjiacun. Despite existing literature on capacity estimation that indicates the capacity coefficient is site-specific and hence varies for different studies, the comparison effort of Goodman et al. (2013) on six methods for estimation of CO₂ storage capacity reveals the CO₂ storage efficiency coefficient is typically lower than 4%. The efficiency given in US-DOE (2012) ranges between 0.7% and 4.7% based on their 15th to 85th percentiles. These values refer to either basin or formation scale assessments, rather than for site-specific methods. The ranges of site-specific efficiency would be expected to be larger than the ranges reported in those articles. Table 5 shows the model-estimated storage efficiency for each formation unit of interest. The storage efficiency, however, are observed to be lower than 3%. This is due to the low permeability/porosity of the reservoir.

Fig.9. Distribution of CO₂ saturation (a), CO₂ density (b) and mass fraction of CO₂ dissolved into the brine (c) under the Chenjiacun reservoir conditions after 3 years of injection with a constant injection pressure of 1.5 times hydrostatic pressure.

Table 5 Parameters for estimation of storage capacity for each reservoir at Chenjiacun storage site.

Parameter	Symbol	Unit	Formation unit				
			LJG	SQF	SHZ	SHX	MJG
Trap area	A	m ²	3141593	3141593	3141593	3141593	3141593
Net thickness	H	m	74.0	45.6	35.4	32.4	31.2
Gross thickness	H _g	m	123.0	291.0	242.0	84.0	85.6
Porosity	Ø	-	0.105	0.108	0.106	0.096	0.035
CO ₂ density ^a	ρ _{CO2}	kg · m ⁻³	789.7	771.7	757.5	751.2	743.7

Brine density ^a	ρ_w	$\text{kg} \cdot \text{m}^{-3}$	1025.69	1013.96	1010.63	1009.55	1016.7
Pore compressibility	β_p	GPa^{-1}	0.680	0.670	0.638	0.653	0.928
Brine compressibility ^b	β_w	GPa^{-1}	0.45	0.35	0.25	0.21	0.20
Sustainable Pressure buildup ^c	ΔP	MPa	6.97	7.78	9.20	10.42	10.79
Storage efficiency coefficient ^a	E	%	3.258	0.743	0.557	0.477	0.415
CO ₂ saturation ^a	S_g	-	0.316	0.279	0.281	0.269	0.248
Mass fraction of CO ₂ dissolved in brine ^a	$X_{\text{CO}_2,\text{aq}}$	-	0.0440	0.0457	0.0450	0.0453	0.0472
Geometric and heterogeneity capacity coefficient ^{a,d}	$C_g C_h$	-	0.061	0.021	0.015	0.012	0.013

^asimulation result; ^bestimated from Zhou et al. (2008); ^c50% of the initial pressure at the top of the formation unit;

^dDoughty et al. (2001)

Fig.10. Estimated storage capacities with three different methods for each reservoir at Chenjiacun

Fig.10. illustrates the resulting estimates of storage capacity with the three methods described in Section 4. It is clearly shown that the US-DOE (2012) method and the Doughty (2001) method give similar estimates except for LJG, while they are significantly different than estimates by the Zhou et al. (2008) method, except for SQF. The US-DOE (2012) method and Doughty (2001) method present similar estimates

because in essence they use same concepts for calculation. The Zhou et al. (2008) method reports the lowest estimate for the LJG unit but the highest estimates for the others, indicating the closed-boundary conditions intrinsically applied for the Zhou et al. (2008) method only impact injection in the LJG reservoir. The Zhou et al. (2008) method gives generally high estimates because the calculating formula explicitly includes sustainable pressure buildup, which, nevertheless, may not reach 1.5 times the hydrostatic pressure in simulations with open boundary conditions. For a 1000 m radius (or 3.14 km² radial trap area), the storage capacity of the LJG unit is 0.25~1.04 Mt and the SQF and SHZ unit have generally smaller storage capacities (0.51~0.60 Mt and 0.30~0.50 Mt, respectively) due to significantly lower storage efficiency. In contrast, the SHX unit has relatively small storage capacity and the MJG unit has the smallest capacity, owing to comparatively thin formation, low permeability/porosity and low storage efficiency. Summation of these estimates for each formation unit results in 1.60~2.07 Mt for the total storage capacity of a 3.14 km² area for 3 years of injection at the Chenjiacun storage site, which alternatively means 0.53~0.69 Mt·yr⁻¹ for a single vertical injection well. Such a storage capacity level is greatly insufficient to deal with the current and foreseeable future emissions of CO₂ in this area because the annual emission from the CSCLC was reported to be approximately 3 Mt of CO₂ (Wu et al. 2013). About 5 injection wells may be required to store such an amount. Injectivity-improving methods or larger-scale sequestration projects are therefore suggested to counteract the carbon emissions in this area.

5.6. Effects of relative permeability on injectivity

Since we consider all injection simulations with the same constant injection pressure, injectivity can be evaluated conveniently by comparing injection rates. From the extension of Darcy's law for multiphase flow, the injection rate of CO₂ into a reservoir is dependent on fluid density, injection pressure, rock intrinsic permeability, and CO₂ mobility, the last of which is defined by relative permeability divided by viscosity. Since Zhang et al. (2013) has investigated the influence on injection rate of all these parameters except relative permeability, various saturation – relative permeability curves are defined for this study, using the parameters in Table 6. Fig. 11 illustrates these relative permeability curves and the resulting simulated injection rates. For all of these relative-permeability cases, the effective brine permeability is initially equivalent to the intrinsic matrix permeability of 10.6 mD, due to no CO₂ present in the reservoir before injection. With the increase of CO₂ saturation due to injection, the brine saturation decreases and the relative permeability to brine decreases accordingly. The CO₂ continues to impact brine mobility until the brine arrives at irreducible saturation, at which point brine relative permeability becomes zero. The effective permeability of CO₂ also increases with CO₂ saturation, attaining a certain value less than 10.6 mD at the maximum gas saturation. Comparison of the injection rates between the relative-permeability curves in Fig. 11 verifies the effect of relative-permeability curve on the injection rate. A small irreducible water saturation or large residual gas (CO₂) saturation and large van Genuchten exponent favor

injection of CO₂, resulting in high injection rate. This is because a reservoir with small irreducible water saturation provides more space and also opportunity for CO₂ to flow through it. A reservoir with great residual CO₂ saturation makes more immobile CO₂ trapped by capillary pressure and hence enhances solubility trapping and storage safety. Finally, the van Genuchten exponent reflects the distribution of the reservoir pore size, with larger exponent value corresponding to a more uniform distribution of pore size. As is shown in Fig. 11b, larger values for the van Genuchten exponent result in greater relative water permeability, facilitating CO₂ flow as well.

Table 6 Varying parameter settings for saturation-permeability curves for CO₂ injection simulation of the LJG reservoir.

Parameter	Pore size distribution coefficient ^a	Irreducible water saturation	Residual gaseous saturation
Symbol [unit]	m [-]	$S_{w,r}[-]$	$S_{gr}[-]$
1	0.4	0.40	0.05
2	0.6	0.40	0.05
3	0.8	0.40	0.05
4	0.6	0.40	0.15
5	0.6	0.20	0.05

^aVan Genuchten exponent (Mualem, 1976; Van Genuchten, 1980)

Fig. 11. Injection rates (a) and the associated saturation-permeability curves employed in the flow simulation (b). K_{rw} (solid line) and K_{rg} (dash line): water and CO₂ relative permeability, respectively. S_w : water saturation. The curve numbering is referred to Table 6. The CO₂ relative permeability curves 1 and 2 are the same as 3 and hence are covered by it.

5.7. Injection strategies for improving storage efficiency

5.7.1. Pressure management

Carbon dioxide storage efficiency gauges the fraction of the accessible pore volume that will be occupied by the injected CO₂ (Goodman et al., 2011). For a particular

reservoir with an extent sufficiently larger than the CO₂ plume size within a certain time, the storage efficiency can be alternatively examined by looking into the cumulative CO₂ mass injected into the reservoir. The percentage of the CO₂ dissolved into the formation brine can be seen as an important measure of the post-injection storage safety and security. Four simulation scenarios were run considering different injection strategies for the Chenjiacun storage site, to gain insights into optimization of the injection plan. For an open-boundary reservoir, the storage efficiency is dependent on the fluid displacement. This is supposedly the case for the studied site because low pressure buildup has been prevailing therein since shortly after the commencement of injection. Producing water prior to or during the injection period in effect lowers the reservoir pressure and directs the flow and therefore hopefully improves the storage efficiency. Fig. 12 compares the cumulative CO₂ mass injected into the reservoir and the percentages of the CO₂ dissolved in the formation brine for varying injection strategies. The case ‘Continuous CO₂ Injection’ serves as the base case of the simulations, and considers continuous injection of CO₂ under the constant injection pressure of 1.5 times hydrostatic pressure over 3.65 years of simulation. The additional three cases are described in the Fig. 12 caption. **The plume for these cases expands radially to about 400 m away from the injection well (Fig. 13).** Significantly enhanced CO₂ storage is observed for the case “Simultaneous Water Withdrawal” (SWW), in which CO₂ was injected with one additional water-production well located 800 m west of the injection well (Fig. 12a). Pumping water prior to CO₂ injection (PWW) helps as well but the effect is marginal for our case due to the short duration of both pumping and simulation. In contrast, CO₂ storage, as expected, was observed to be the smallest of the four cases if injecting water before CO₂ injection takes place (namely, PWI). Although injection of fresh water helps lower the salinity of the native brine and thereby improves both the mobility of brine and CO₂ solubility in the brine, it enhances the reservoir pressure as well. For this particular case, the reduction in injectivity caused by pressure increase outweighs the injectivity improvement due to reduced salinity, resulting in the lowest storage efficiency. This implies that pressure buildup is a more important concern relative to mobility, particularly for deep and low-permeability reservoirs. Efforts should therefore be put on pressure management for solving the injectivity problem and thereby improving storage efficiency at low-permeability storage sites such as Chenjiacun. Fig. 12b illustrates the relatively higher percentages of CO₂ dissolved in the brine obtained by injecting CO₂ along with water production before or during the injection period. CO₂ dissolution into the formation brine favors storage capacity, and also generally enhances storage safety if the injection is deep and the reservoir is well confined.

Despite the demonstrated advantage of introducing a water-production well into our CO₂ injection scenario, one downside of this strategy is the added risk of CO₂ leakage through potential preferential-flow pathways or the production well itself. Fig. 13 illustrates **the** risks of this strategy (i.e. “Simultaneous Water Withdrawal”) by comparing the lateral extent of the CO₂ plume between the four cases. Regardless of only 3.65 years of injection in this low-permeability reservoir, it can be observed that the injected CO₂ accompanied by water production 800 m west of the injection center

travels faster than the base case and the other two scenarios (as indicated by the dark blue vertical line in Fig. 13). Prior water injection or withdrawal does not seem to affect the plume migration, although it may impose some effects on the CO₂ dissolution as demonstrated in Fig. 12b. From the simulation results the lateral migration distance of the CO₂ plume is expected to be approximately 1000 m at the Chenjiacun site after 100 years of storage. Therefore, we suggest that the location of a water-production well be around 1000 m or further away from the injection well in case this injection strategy is applied to this site for large-scale CO₂ storage.

Fig. 12. Cumulative injected CO₂ mass (a) and percentage of the CO₂ dissolved into the formation brine (b) plotted against injection time for varying injection strategies. Continuous CO₂ Injection (CCI) serves as the base case: injecting CO₂ throughout the 3.65 years of simulation period. Simultaneous Water Withdrawal (SWW): injecting CO₂ at the center (X=0) with simultaneous production of water at X=-800. Prior Water Injection (PWI): injecting fresh water for two months followed by 3.65 years of CO₂ injection. Prior Water Withdrawal (PWW): pumping water for two months followed by 3.65 years of CO₂ injection.

Fig. 13. Vertical CO₂ plume profiles for varying injection schemes (a-d). The dark blue vertical line is shown to facilitate comparison of the location of the plume fronts between the cases.

5.7.2. Perforated interval and time schedule

To examine how the perforated interval and time scheduling affect the storage efficiency and also safety, various simulation cases were run with different injection and time schemes. All these simulation runs were performed under condition of constant injection pressure, which is set to 1.5 times hydrostatic pressure. Fig. 14a- and 14b investigate the effects on the cumulative CO₂ mass injected of different vertical injection positions (i.e. depths). Injection at the upper reservoir is clearly observed to lead to more cumulative CO₂ mass stored and a greater CO₂ percentage dissolved into the formation brine. In contrast, injecting CO₂ in the lower reservoir results in much smaller CO₂ storage and also lower dissolved percentages, which is undesirable from both financial and storage safety perspectives. Fig. 14c- and 14d compare the storage amounts of CO₂ and the percentages dissolved between three different injection schemes. For the sake of convenience, the names of the cases are denoted as acronyms and have been described clearly in the caption of Fig. 14. The case EIDISU serves as a base case here by simulating CO₂ injection into each reservoir unit separately upwards and with identical injection duration. EIDIPIU

considers identical injection duration but injecting with an increasing perforated interval upwards, from only perforated in the MJG. To analyze the potential effect of time scheme, IIDIPU simulates injection from the lower reservoir to the upper with an increasing injection duration and an increasing perforated interval upwards, relative to the lowest injection reservoir (i.e. MJG). It can be seen that the cumulative CO₂ mass storage for IIDIPU is significantly more than the other two scenarios. This indicates that adopting an injection strategy as IIDIPU, namely injecting with long perforated interval but with longer injection duration to the upper reservoir (i.e. the LJG unit for the studied case) helps improve the storage efficiency at the Chenjiacun site. We therefore suggest that when using vertical wells, fully penetrating wells should be used to maximize the maximum injection rate of the aquifer.

Fig.14. Comparison of the cumulative mass of the injected CO₂ and the dissolved fractions for constant-pressure injection at different injection positions (i.e. upper, middle, and lower). IIDIPU: increasing injection duration and increasing perforated interval upwards; EIDIPIU: equal injection duration and increasing perforated interval upwards; EIDISU: equal injection duration and injecting separately upwards.

6. Comparison with other sites

Given that the site of interest has somewhat unique characteristics such as its low permeability formations, it is quite useful to compare the characteristics of the

Chenjiacun site with the other typical storage sites across the world. As stated before, both the injectivity and storage capacity of a reservoir are dependent on many factors. Typically they may change with injection and boundary conditions, injection duration and reservoir properties. Table 7 lists some information of interest about the Chenjiacun site and five other sites for the purpose of comparison. It is hard to compare the injectivity between the sites due to data deficiency. Therefore, we compare in Table 7 the average **actual** injection rates for **an** individual well. To date, the average injection rate at Chenjiacun is 0.068 Mt/year, which is significantly smaller than the other sites except Ketzin (Table 7). As indicated in Eq. (1), the injectivity is largely dependent on the reservoir permeability and thickness. Of all these sites, Chenjiacun has the greatest reservoir thickness. The cumulative thickness of the storage reservoir (218.6 m) at Chenjiacun is over 20 times **that at** Sleipner, about 10 times **that at** In Salah and Weyburn, and 2 – 3 times **that at** Ketzin and Snøhvit. Comparatively, In Salah has more analogous site characteristics to Chenjiacun in term of the reservoir condition (e.g. depth, lithology, pressure, etc.). However, the reservoir permeability at Chenjiacun is much lower than **Sleipner, Snøhvit, and Ketzin**. Apart from the reason of low permeability and porosity, different well design is a factor when Chenjiacun is compared with In Salah and Weyburn, in both of which horizontal wells are employed. At this point, one should bear in mind that the resulting relatively low average injection rate at Chenjiacun is **partially** an ‘artifact’ caused by frequent shut-in and first-time prudence to minimize risk. Our estimation with both an analytical method and numerical simulations presented herein indicates the **maximum injection rate** at this site should be much more than that since the observed pressure buildup was low (about 3 MPa). As indicated in Table 7, the pressure buildup at Chenjiacun was significantly lower than that at In Salah and Snøhvit, but comparable to that at Sleipner, where only a small pressure buildup has been observed in the reservoir since injection began in 1996 (Eiken et al., 2011). It is not possible to accurately compare the storage capacity between different sites because CO₂ storage capacity is not **an absolute constant, especially for a particular site**. Rather, it depends on many factors such as the number and design of injection wells, injection strategy, and risk acceptance (Eiken et al., 2011). **The comparison herein is just a preliminary semi-quantitative analysis**. At Sleipner, owing to its high permeability and porosity as well as its open boundary conditions, it is a consensus that the **maximum injection rate** and storage capacity are plentiful. For similar operating conditions, both the injectivities and storage capacities at In Salah and Snøhvit should be smaller than Sleipner. High pressure buildup (above 9 MPa) observed at these two sites is proof of this, despite the choice of drilling three horizontal injection wells at In Salah. Weyburn attains over 2.4 Mt **newly injected (i.e. excluding recycled)** CO₂ per year by virtue of a large number of injection wells. With regard to the Chenjiacun site, as presented before, the storage capacity is estimated to be about 0.61 (0.53~0.69) Mt per year with around 3 MPa of pressure buildup (Table 7). The storage capacity is not so disappointing in this low-permeability reservoir, primarily owing to its large thickness.

Table 7 Comparison between Chenjiacun and world famous sites. Relevant references (^bCantucci et al., 2009; ^aCavanagh, 2013; ^aCavanagh and Haszeldine, 2014; ^{a,c,d}Eiken et al., 2011; ^dGrude et al., 2014; ^dHansen et al., 2013; ^bNjiekak et al., 2013; ^eNorden and Frykman, 2013; ^bPreston et al., 2009; ^bRyerson et al., 2013; ^bShevalier et al., 2013; ^{c,d,e}Trémosa et al., 2014; ^bWhite, 2013; ^bWhite and Johnson, 2009).

	Chenjiacun	Sleipner ^a	Weyburn ^b	In Salah ^c	Snøhvit ^d	Ketzin ^e
Country	China	Norway	Canada	Algeria	Norway	Germany
Location type	onshore	offshore	onshore	onshore	offshore	onshore
* Injection rate (Mt·yr ⁻¹)	0.068	0.82	<0.30	0.28	0.73	<0.028
* Maximum injection rate (kg·s ⁻¹)	11	0.90	1.97	NA	23	0.89
Storage capacity (Mt·yr ⁻¹)	0.53~0.69	>0.85	>2.4	0.85	0.53	0.06
Reservoir thickness (m)	218.6	<10	21	20	110	71~74
Reservoir permeability (mD)	<11	>1000	Marly, <10; Vuggy, 50	10	> 500; 185~883	50~100
Reservoir porosity (%)	10	35~40	Marly, 26; Vuggy, 15	13~20	10~15	23
Pressure buildup (MPa)	3	Very small	mostly <5	10	9	NA

* both injection rates and the maximum injection rates refer to the case of a single well.
NA: Not Available.

7. Summary and conclusions

Simulations run for the past three years (2011-2014) of injection demonstrate that the Triassic LJG Sandstone in the upper portion of the sedimentary section is the primary reservoir for CO₂ storage at Chenjiacun, and provides approximately 80% of the injectivity of the site. By contrast, the injectivity in the limestone reservoir (Ordovician MJG Fm.) in the lower portion provides less than 3% of the injectivity of the site. Simulations show that the plume would expand radially to approximately 1000 m after injecting about 2 Mt of CO₂ under a constant injection pressure of 1.5 times hydrostatic pressure and storing it for 100 years. The reservoir pressure buildup is mostly lower than 5 MPa for the adopted injection plan, which is far below the fracturing pressure of the formation.

The injectivity and storage capacity were estimated by analytical methods and

dynamic numerical modeling for the reservoirs at Chenjiacun. The analytical estimates of the mass injectivity of the LJG reservoir is $4.06 \times 10^{-6} \text{ kg} \cdot \text{Pa}^{-1} \cdot \text{s}^{-1}$, which has about 64% of the injectivity of the entire reservoir system, followed by the SQF unit, which accounts for some 15.8%. The **maximum injection rate** for the LJG reservoir is estimated to be roughly $15.1 \text{ kg} \cdot \text{s}^{-1}$ for the highest injection pressure that is 1.5 times initial hydrostatic pressure, leading to 476,000 tonnes of CO_2 injected per year. The **maximum injection rates** for the other four reservoirs are substantially smaller than that for the LJG reservoir. The injectivity of the LJG reservoir estimated by numerical simulation ranges from 0.7 to $3.0 \times 10^{-6} \text{ kg} \cdot \text{Pa}^{-1} \cdot \text{s}^{-1}$. The injectivity of the SQF reservoir was estimated to be from 0.2 to $1.1 \times 10^{-6} \text{ kg} \cdot \text{Pa}^{-1} \cdot \text{s}^{-1}$. The injectivities of the remaining reservoirs (i.e., SHZ downward) are smaller than $0.6 \times 10^{-6} \text{ kg} \cdot \text{Pa}^{-1} \cdot \text{s}^{-1}$. The **maximum injection rate** estimated from the numerical simulation is approximately 17 kg/s, leading to 536,000 tonnes storage of CO_2 with the injection pressure constrained to be 1.5 times hydrostatic pressure. The **maximum injection rates** estimated by the numerical model are smaller than those obtained by the analytical method. One reason for this is that the numerical modeling takes into account the buoyancy of CO_2 **and reservoir heterogeneity, which may reduce injectivity and injection rate**. The numerical model herein was calibrated with site-specific observations, which could be a result of various complex and uncertain factors such as stimulation, pressure management, and reservoir self-modification due to geochemical reactions. The difference in the estimates between the two approaches also could be partially due to wellbore effects (e.g. thermal exchange). These combined effects, however, can hardly be included in the analytical estimation.

The storage efficiency of Chenjiacun is **calculated** to be lower than 3%. The storage capacity of the Chenjiacun storage site is about 1.60~2.07 Mt for a 1000 m circular area for 3 years of injection, with the current injection well. Therefore the CO_2 disposal capacity of the Chenjiacun site is estimated to be 0.53~0.69 $\text{Mt} \cdot \text{yr}^{-1}$. About 5 injection wells may be required to deal with the current CO_2 emission rate, which is about 3 Mt per year. The injectivity and storage capacity at Chenjiacun are not too small in comparison with other reported storage sites such as In Salah and Ketzin (Table 7), owing to its relatively great thickness and long perforated interval.

A number of injection strategies and reservoir management options are available to enhance the reservoir injectivity and storage capacity. Of course, a widely accepted strategy for injectivity problems is to drill more wells **that are widely separated, and inject in each** at a lower injection rate. But besides that, as far as Chenjiacun is concerned, these optimization strategies include:

- (1) Stimulation **or other reservoir modification** measures to obtain higher intrinsic permeability, smaller irreducible water saturation **or** greater residual gas saturation,
- (2) Introduction of additional water-production wells about 1000 m away from the injection well for large-scale CO_2 storage,
- (3) Using fully penetrating and long perforated vertical wells to maximize the **maximum injection rate** of the aquifer, and
- (4) Conducting longer-duration injection for the upper reservoir (i.e. the LJG unit) in case a 'layer-by-layer' injection plan is applied.

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