Effects of Injection Pressure on Geological CO\textsubscript{2} Storage in the Northwest Taiwan Basin

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ABSTRACT

Geological storage of CO\textsubscript{2} has been viewed as an effective means of reducing CO\textsubscript{2} emissions and mitigating the greenhouse effect. In the Taiwan area, the Western Taiwan Basin is suitable for million-ton-scale geological CO\textsubscript{2} storage. Numerical methods were used in this study to investigate reservoir performance under various injection pressures. Three formations in the basin, the Chingshui Formation, Kueichulin Formation and Nanchunag Formation, were modeled. Three different injection pressures (1.3, 1.5 and 1.7 times the initial pressure) were considered. The simulation results show that the cumulative injected CO\textsubscript{2} mass is proportional to the applied injection pressure and that the storage security increases over time. An annual injection rate of 5 Mt year\textsuperscript{-1} could be achieved by applying an injection pressure of 1.5 times the initial pressure at the injection well. The pressure accumulation in the system featured three stages. The over-pressurization effects associated with the injection in the system decrease, and the pressure in the system almost returns to the original pressure conditions after 50 years following cessation of injection. The CO\textsubscript{2} gas plumes simulated in this study also suggest that the modeled injection scenarios are safe in terms of CO\textsubscript{2} leakage from the vertical fault in this area.

Keywords: CO\textsubscript{2}; Geological storage; Simulation; Injection pressure; Fault.

INTRODUCTION

A large amount of CO\textsubscript{2} has been produced by the combustion of substantial quantities of fossil fuels by humans for energy and industrial activities. Because of its predominance among the greenhouse gases in the atmosphere, CO\textsubscript{2} is thought to be the main cause of global warming. The increase in the atmospheric concentration of CO\textsubscript{2} is responsible for approximately 64% of the increase in ‘greenhouse effects’ (Bryant, 1997). Therefore, reducing CO\textsubscript{2} emissions is crucial for mitigating the effects of global warming, such as glacial melting, extreme weather, and rising sea levels. Geological CO\textsubscript{2} storage (GCS) (Soong et al., 2014), which involves the injection of CO\textsubscript{2} into deep formations, is an effective way to reduce CO\textsubscript{2} emissions and has been applied for nearly 20 years since the start of the first GCS project. The formations that can accommodate CO\textsubscript{2} are commonly depleted oil or gas reservoirs, unmineable coal beds, and saline aquifers at depths greater than 800 m. Given the general geothermal and pressure gradients, CO\textsubscript{2} at these depths exists in a supercritical state, in which its density is similar to that of a liquid (200–1000 kg m\textsuperscript{-3}) but its compressibility is as high as that of a gas. Therefore, the storage capacity in these deep formations can be very high (Bachu et al., 2007; Benson and Cole, 2008). The International Energy Agency estimates that carbon capture and storage (CCS) will contribute to up to 20% of the CO\textsubscript{2} emission reductions in 2050, which is approximately equivalent to the contributions from efficiency improvements and renewable energy replacement of fossil fuels. A suitable reservoir with good sealing structures can guarantee long-term storage of CO\textsubscript{2} for large-scale applications. For example, as part of the ongoing Sleipner Project in Norway, which was the first large-scale CCS/GCS project worldwide, one million tons of CO\textsubscript{2} (Mt) have been injected per year into saline aquifers that were approximately 3000 m deep starting 1996, and no leakage has been observed to date (Kongsjorden et al., 1998). Projects of a similar scale also exist elsewhere in the world, including Illinois, USA (Holloway, 1997; Orr Jr., 2004; van Alphen et al., 2010). In Taiwan, approximately 200 to 300 Mt CO\textsubscript{2} has been emitted annually in recent years (Li et al., 2013). The government has committed to reducing the annual CO\textsubscript{2} emissions to the levels observed in the early 2000s by 2025 and to further reduce the level by 50% by 2050 (Li et al., 2013). To achieve this reduction...
goal, at least 90 Mt CO₂ needs to be removed from the emissions every year. Based on the geology of Taiwan, the Western Taiwan Basin is the highly potential candidate site for large-scale geological CO₂ storage. Below a depth of 800 m in this area, there are saline aquifers with porosities and permeabilities that are high enough to have good injectivity (Benson and Cole, 2008). A comprehensive study on large-scale geological CO₂ storage in the Western Taiwan Basin was conducted to assess the behavior of the reservoir under a hypothesized injection rate of 5 Mt for 50 years. The behavior was assessed in terms of the pressure accumulation, CO₂ plume migration, risk of leakage from a fault and mechanical displacement (Li et al., 2013). More recent research on CO₂ capture technologies and mobility in the saline aquifers, like Yang et al. (2014), Jean et al. (2016), Wu et al. (2016), and Adelodun et al. (2016), further improves the confidence in carrying out CO₂ capture and storage in Taiwan in the foreseeable future.

Li et al. (2013) concluded that the aquifer at depths from 1500 m to 2000 m could safely contain a large amount of CO₂ for a long period of time (Li et al., 2013). However, in reality, the amount of CO₂ that could be injected under a certain injection pressure may be more interesting because the injection pressure applied to the wellhead should remain at a safe value. Therefore, in this study, the reservoir performance under various injection pressures was examined numerically to complement the previous assessment and provide another reference for a future project aiming to design the injection procedure.

METHODS

Site Description

The study area is approximately 50 km × 70 km, which is slightly larger than that in the previous assessment, and is located in northwest Taiwan (Fig. 1). The geological setting of the site is stable. The Tertiary sedimentary basins in this region have been the targets of petroleum exploration (Shaw, 1996), and many wells for oil exploration or production have been drilled in this part of Taiwan. A geological profile along three petroleum exploration wells drilled in or around the study area shows that the formations, including the Chingshui (CS), Kueichulin (KC), and Nanchang (NC) formations, represent a good combination of seals and reservoirs for CO₂ storage (Fig. 2). The CS formation is mainly composed of shale and has a thickness ranging from 100 m to 200 m, an average porosity of 5% and a horizontal permeability of 10⁻¹⁸ m². The KC formation is sandstone interbedded with siltstone and shale. The NC formation consists of protoquartzite, subgraywacke and shale and is intercalated with coal seams. Both the KC and NC formations have large thicknesses (300 m or over), high porosities (20%–25%) and high permeabilities (10⁻¹⁴ m²–10⁻¹³ m²). Thus, these formations could be a good reservoir in which to store a large amount of CO₂. A vertical fault northwest of the study area (Fig. 1) cuts through the three formations and the overlying formation. CO₂ could possibly use this fault as a path to escape from the deep reservoir. However, the previous assessment indicated that the presence of a three-phase zone (liquid water, liquid CO₂, and gas) would make all of the phases less mobile by reducing their relative permeability as CO₂ attempts to move toward the surface (Li et al., 2013). Two injection wells, 8 km apart, were assumed to be placed in the middle of the study area in the horizontal direction, and their screened section were situated in the lower half of the KC formation. The KC formation would be the primary stratum to storage CO₂, the NC formation would be the secondary reservoir, and the CS formation would act as the seal. The NC formation is also a good target for CO₂ disposal, however, the NC formation is deeper than the KC formation. For an economic view, it will cost more for drilling and injection. That is the reason the KC formation is considered as the first primary site for storage. The configuration of the injection wells is the same as in our previous work (Li et al., 2013); thus, the shortest distance from each well to the fault is also 16 km.

Simulation Tool

All the simulations in this study were run on TOUGH2-MP/ECO2N (Zhang et al., 2008), the parallel version of the ECO2N module of TOUGH2 (Pruess et al., 1999, Pruess, 2005). TOUGH2, with the fluid property module ‘ECO2N’, describes the non-isothermal multiphase flow in a porous–media system with H₂O, NaCl and CO₂. This module can depict CO₂ disposal in a saline aquifer with temperatures of 12°C to 110°C, pressures of up to 60 MPa, and salinities of zero to saturation. The equations involved in the simulation are not presented here because they can be found in the TOUGH2 manual (Pruess, 2005).

Discretization and Parameterization

An irregular 3D mesh was applied to the three formations within the study area (Fig. 2(a)). The mesh was similar to the mesh used to investigate the CO₂ flow characteristics in the reservoir in the previous assessment. The CS, KC and NC formations were evenly divided into 4, 15 and 10 layers, respectively. The horizontal grids in Fig. 2(b) show that the areas around the injection wells and the fault had a higher resolution than other locations. The area within 100 m of each injection well was radially discretized into varying radii from 2 m to 20 m. The fault was 10 m wide, and the neighboring grids within 250 m on both sides had widths that grew from 10 m to 100 m outward. Outside these zones, the grids were gradually reshaped to squares with widths increasing from 50 m to 500 m. The 29 layers contained 24,614 grid blocks per layer, resulting in a total of 73,806 grid blocks and 2,061,182 connections. The reservoir was modeled as a homogenous and anisotropic medium under the assumption that CO₂ injection would not change the original thermal conditions of the reservoir. The hydrogeological parameters assigned to the formations were based on their average permeability and porosity. The ratio of vertical permeability to horizontal permeability in these formations was 1:10. The wells and the fault were treated in the model as media with a very high vertical permeability of 10⁻¹⁵ m². The capillary pressure was simulated after van Genuchten (1980). The relative permeabilities of the aqueous phase
Fig. 1. (a) The study area. (b) Geology of a cross section of three oil wells in or around the study area.
Fig. 2. Discretization of the model: (a) in a 3D view; (b) in a planar view; and (c) zoomed in on one injection well.
and gas phase were calculated using the equations proposed by van Genuchten (1980) and Corey (1954), respectively. The main parameters for the formations in the model are shown in Table 1.

### Initial Conditions and Boundary Conditions

The initial conditions were obtained by running the hydrostatic equilibrium of the model with a geothermal gradient of 30 °C km⁻¹ starting at a land surface temperature of 20°C, a pressure gradient of 10 MPa km⁻¹ starting at a surface atmospheric pressure of 1 Bar, and water at a saturated state with a salinity of 3.2% and no CO₂. Two types of boundary conditions, a fixed-pressure boundary and a no-flow boundary, were used in the model (Fig. 3). The lateral boundaries that are parallel to the fault were fixed-pressure boundaries; the other lateral boundaries, i.e., the top of the model and the bottom of the model, were no-flow boundaries. These boundary conditions were set for two reasons: (1) to reduce convergence errors and make the computation faster and (2) to facilitate propagation of the injection pressure towards the fault. The injection wells were also represented by a fixed-pressure boundary with a CO₂ saturation of 1.0 the entire time. The pressure at the grid blocks representing the wells was assumed to be 1.3 to 1.7 times the initial pressure, varying with the simulation scenarios.

### Simulation Scenarios

The simulations were run under three different scenarios that had fixed pressures of 1.3, 1.5 and 1.7 times the initial pressure (P₀) at the grid blocks of the injection wells. Each scenario was run for a period of 500 years, and it was assumed that the injection would continue at both wells for the first 50 years and then cease for the remaining years. Diffusion of CO₂ was neglected in the simulations. The results of the CO₂ plume evolution, pressure accumulation in the formations, and storage capacity, and risk of CO₂ leakage through the fault under these scenarios were compared and discussed.

### RESULTS AND DISCUSSION

#### Evolution of the CO₂ Plumes

Fig. 4 shows that the pattern of gas CO₂ migration from the two wells was similar in each scenario, although the size of the plume at a given time differed among the scenarios.

### Table 1. Relevant parameters assigned to the formations in the model.

<table>
<thead>
<tr>
<th>Formation</th>
<th>CS</th>
<th>KC</th>
<th>NC</th>
</tr>
</thead>
<tbody>
<tr>
<td>Porosity (%)</td>
<td>5</td>
<td>25</td>
<td>20</td>
</tr>
<tr>
<td>Horizontal permeability: Kₓ, Kᵧ (10⁻¹⁵ m²)</td>
<td>0.001</td>
<td>100</td>
<td>10</td>
</tr>
<tr>
<td>Vertical permeability: Kₜ (10⁻¹⁵ m²)</td>
<td>0.0001</td>
<td>10</td>
<td>1</td>
</tr>
<tr>
<td>Entry capillary pressure (kPa)</td>
<td>62.0</td>
<td>3.58</td>
<td>3.58</td>
</tr>
<tr>
<td>Pₘₐₓ (Pa)</td>
<td>10⁷</td>
<td>10⁷</td>
<td>10⁷</td>
</tr>
<tr>
<td>λ</td>
<td>0.4</td>
<td>0.4</td>
<td>0.4</td>
</tr>
<tr>
<td>Sₑ</td>
<td>0.2</td>
<td>0.2</td>
<td>0.2</td>
</tr>
<tr>
<td>Sₑₑ</td>
<td>0.05</td>
<td>0.05</td>
<td>0.05</td>
</tr>
<tr>
<td>Sₑₑₑ</td>
<td>1</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Sₑₑₑₑ</td>
<td>0.999</td>
<td>0.999</td>
<td>0.999</td>
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Fig. 3. The boundary conditions for the model.
Due to buoyancy, the majority of the gaseous CO2 rose, accumulated immediately below the CS formation, and subsequently migrated along the interface to a higher location (Fig. 4(a)). At 500 years, the two plumes appeared to merge together in all three scenarios (Fig. 4(b)). The pressure at the bottom of the KC formation caused a small amount of gaseous CO2 to move down into the NC formation. Because of the higher injection pressure, Scenario 3 produced a more extensive plume in the KC formation and a longer penetration into the NC formation than the other scenarios. Fig. 5 shows that, at the end of the injection period, the leading front of the plume traveled along the topographic variations toward the fault, a distance ranging from 2000 m to 4000 m in these scenarios (Fig. 5(a)). At the end of 500 years, the front traveled the longest distance in Scenario 3, 12 km, but did not reach the fault (Fig. 5(b)).

**Pressure Accumulation in the Formations**

Fig. 6 shows that the maximum pressure accumulation in the reservoir experienced three stages, which included the injection duration, the first 50 years following cessation of injection, and the following 400 years. During the first stage, the maximum pressure accumulation in these scenarios remained nearly stable and was slightly above half of the pressure difference from the initial pressure, with an exception at the very beginning of the injection when the maximum pressure accumulation was equal to the overpressure of injection. In the first stage, the scenarios of 1.3 $P_0$, 1.5 $P_0$, and 1.7 $P_0$ featured maximum pressure accumulations of 0.18 $P_0$, 0.28 $P_0$ and 0.38 $P_0$, respectively. In the second stage, although the value of the maximum pressure accumulation varied between these scenarios, the values to which the pressure accumulation dropped were almost the same (approximately 0.04 $P_0$). In the third stage, little difference was present in the evolution of the pressure accumulations in the three scenarios. At the end of the simulation time, the maximum pressure accumulation in all three scenarios was approximately 0.02 $P_0$. Therefore, it would take a few hundred years for the reservoir to recover to its initial pressure conditions after the injection ceased. Fig. 7 shows the migration of the location of the maximum pressure accumulation during the simulation time in these scenarios.

The points from right to left in the plot for each scenario indicate the locations of the maximum pressure accumulation at various times between the start of injection and 500 years. During the injection period, the maximum pressure accumulation was next to the lowest injection point in the KC formation. However, once the injection stopped, the maximum pressure accumulation immediately moved up into the CS formation and stayed there. As the pressure travelled through the system, the maximum pressure accumulation in the reservoir shifted farther away from the injection point.
wells. According to the U.S. Environmental Protection Agency, the pressure in the injection zone must be less than 90% of the fracture pressure of the seal to prevent the creation of new paths for CO₂ leakage (IPCC, 2005). Combined with the pressure accumulation results shown in Fig. 6, the overpressure effects in the assumed injection scenarios would not introduce risks to the long-term CO₂ storage in the study area.

**Fig. 5.** YZ cross-sectional view of CO₂ plumes for well_01 at (a) 50 years and (b) 500 years.

**Fig. 6.** The evolution of maximum pressure accumulation in the reservoir.
Fig. 7. The locations of maximum pressure accumulation at different times in these scenarios.

Storage Capacity for Different Injection Pressures

Fig. 8 shows that the total CO$_2$ mass in the system is dependent on the injection pressure. As shown in Fig. 8, the cumulative injected CO$_2$ masses at 50 years were 170 Mt, 270 Mt and 360 Mt in the scenarios of 1.3 $P_0$, 1.5 $P_0$ and 1.7 $P_0$, respectively. The average annual injection rates in the scenarios were 3.4, 5.4 and 7.2 Mt year$^{-1}$, respectively. Based on the injection rate of 5 Mt year$^{-1}$ that was assumed in the previous assessment, the 1.5 $P_0$ scenario could satisfy the storage goal. Fig. 8 also shows that the security of CO$_2$ storage increases over time following the cessation of injection because more CO$_2$ transitions to the aqueous phase. Each scenario plot clearly shows that the mass of the mobile gaseous CO$_2$ decreases over time, whereas the mass of CO$_2$ in water increases simultaneously. At the end of the simulation time, aqueous CO$_2$ represented 30% to 50% of the mass in the entire system.

Risk of Gas CO$_2$ Leakage through the Fault

Leakage of gas CO$_2$ from the fault is not observed in the results of the simulated 500 years in all scenarios. Fig. 5 shows that the leading front of the gas CO$_2$ plume from well 01 is several to ten kilometers away from the fault (marked as “fracture” in the figure) after 500-year travelling. The distance between the leading front and the fault decreases as the injection pressure increases. So, the shortest distance to the fault is seen in Scenario 3, where the leading front reaches about 4 km to the fault after 500 years. Based on the positions where the leading front reaches in 50 years and 500 years in Scenario 3, it would take about another 150 years for the leading front to reach the fault if the plume moving speed were assumed to be constant. In fact, the plume moving speed is declining after injection stops as the pressure buildup dissipates through the reservoir. Moreover, gas CO$_2$ becomes less as it increasingly dissolves into the saline water during the migration, and due to residual trapping mechanism, much gas CO$_2$ is immobilized. Thus, it can be expected that the amount of gas CO$_2$ capable to arrive at the fault would be too small to form a real leakage. The plume from well 02 has the same situation. Therefore, the likelihood of gas CO$_2$ leaking to the ground surface through the fault is very low in this study.

CONCLUSIONS

The CS, KC and NC formations in the Western Taiwan Basin are suitable for geological CO$_2$ storage to reduce the greenhouse gas emissions in Taiwan. Unlike the previous assessment, in which a fixed injection rate was assumed, this study investigated the reservoir performance under various fixed injection pressures. The CO$_2$ plume evolution, the pressure accumulation in the system, and the storage capacity in scenarios with injection pressures of 1.3, 1.5 and 1.7 times the initial pressure ($P_0$) were simulated with TOUGH2-MP-ECO2N. The results demonstrate that the cumulative injected CO$_2$ mass is proportional to the applied injection pressure. An annual injection rate of 5 Mt year$^{-1}$ could be achieved by applying an injection pressure of 1.5 times the initial pressure at the injection well. The storage security would increase over time following cessation of injection due to the increasing fraction of aqueous CO$_2$ in the system. The percentage of aqueous CO$_2$ increased from less than 10% at the end of the 50-year injection period to approximately 40% a few hundred years after the injection ceased. The maximum pressure accumulation in the system experienced three stages. During the 50 years of active injection, the maximum pressure accumulation was situated next to the lowest injection point in the KC formation and
remained at a relatively stable value that was slightly above half of the initial pressure. During the 50 years following the injection, the maximum pressure accumulation was located in the CS formation and had decreased to approximately 4% of the initial pressure. During the final 400 years, the pressure in the reservoir almost returned to its original values. Moreover, the gaseous CO₂ plumes simulated in this study also suggested that the assumed injection scenarios were still safe in terms of CO₂ leakage from the vertical fault in the area. The longest travel distance of the gaseous CO₂ in the 500-year period in these scenarios was approximately 12 km. The likelihood of gas CO₂ leaking to the ground surface through the fault is very low in this study. Moreover, the shipment of CO₂ from the Taiwan eastern to the western side could be a crucial problem. However, we currently focus on potential site study. The site could be only for the CO₂ resource in western Taiwan, for example, the fossil power plant. The potential of the possible site in eastern Taiwan is not well known yet. Further studies are thus needed and helpful.

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