Potential of carbon dioxide storage from petroleum industries in the Gulf of Thailand for green production

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Abstract. Recently, climate change and global warming are the global concern because of an increase in the huge amount of carbon dioxide (CO₂) in the atmosphere. This gas comes from energy activities and industries like petroleum industries. Carbon capture and storage (CCS) is the practical technology to reduce and storage CO₂. In Thailand, one of the main potential sites for storage is the Gulf of Thailand. However, the research on this issue is very rare in Thailand. Consequently, this work is aiming on the potential study of CO₂ geological storage in formations in the Gulf of Thailand by using simulation. The CO₂ storage capacity, pressure buildup and plume migration have been estimated. Also, this study has been simulated with various conditions. CO₂ injection is used from 1,000-4,000 tons per day with the depth from 2,200-2,330 meters and the results are studied for 50 years as a monitoring period. The results present that with the formation characteristics, CO₂ storage in this area has potential. Moreover, pressure buildup and plume migration are illustrated for the period of 50 years. As a fundamental knowledge, this study can contribute to CO₂ storage in an offshore area in Thailand.

1. Introduction
Nowadays, climate change and global warming are the main global problem because of an increase in the huge amount of carbon dioxide (CO₂) in the atmosphere [1]. This gas comes from energy activities and industries like power generation and petroleum industries [2,3]. Carbon capture and storage (CCS) is the practical technology to reduce CO₂ emitted to the atmosphere and to store it in the potential area.

CCS technology is consisting of three processes. The first process is CO₂ capture. CO₂ will be captured from emission sources [4]. The second process is CO₂ transportation mainly by pipeline and the third process is CO₂ storage especially geological storage [5].

In Thailand, one of the main potential sites for storage is the Gulf of Thailand particularly the depleted oil and gas reservoirs. However, the research on this issue is very rare in Thailand. Consequently, the objective of this work is focusing on the study of the potential sites of CO₂ geological storage in the formations oil and gas fields in the Gulf of Thailand by using simulation. Also, it is aimed to observe the characteristic of CO₂ storage behaviour with the fundamental data in this area.


2. Simulation

2.1 Method

The method of this study is to use the CMG software to set up and simulate the 3D model of CO$_2$ geological storage and to evaluate the behaviour of injected CO$_2$ in the formations. Also, the change of pressure and storage capacity of injected CO$_2$ can be simulated and investigated with the injection rate of CO$_2$ ranging from 1,000 to 4,000 tons/day and time period of observation is 50 years. Furthermore, the selected site of this study is Malay basin in the Gulf of Thailand as shown in figure 1.

![Figure 1. Map of studied area [6].](image)

In this study, Malay basin is selected because this area is not limited by faults and compartment boundaries comparing to adjacent areas in the Gulf of Thailand. Therefore, the pressure can be increased while CO$_2$ injected. However, CO$_2$ injection can affect the shale in the formations because of caprock breaking before CO$_2$ injection is accomplished [7]. The effective of CO$_2$ storage would be limited by pressure buildup [8]. Furthermore, while CO$_2$ is injected, it moves up to the top of the formation and expand radially for the plume migration. Also, the top area are limited by faults and some fined-grained such as shale.

2.2 Fundamental data of formations

The actual, fundamental data to create 3D model is obtained from the literature [6] and the Department of Mineral Fuels, Ministry of Energy as shown in table 1. In this case, the single well consists of 3 layers. Each layer has the characteristics as presented in table 1. The first layer is the bottom sand. The 2nd layer is in middle sand and the 3rd layer is the top sand.

The important condition while injects CO$_2$ is pressure buildup. The fracture pressure is calculated and used to determine the maximum pressure as well as the storage capacity. However, the maximum injection pressure should not exceed to fracture pressure in each well. The fracture pressure that will be fractured rock formation is assumed to use as the limitation of injection pressure. When the pressure is exceeding to minimum principal stress, rock formation will be fractured [9,10]. The maximum pressure is limited at 90% of fracture pressure [9] to storage CO$_2$ without caprock breaking. The fracture pressure is calculated from Hubbert and Willis Equation [10] as shown in equation (1).

$$F_{\text{min}} = \frac{1}{3} \left( 1 + \frac{2P}{D} \right)$$

(1)

Where $F_{\text{min}}$ is fracture gradient and P/D is pore pressure gradient or pressure per depth (psi/ft).
Table 1. Fundamental data of 3 layers in the formation.

| Parameter                  | 1st Layer of sand | 2nd Layer of sand | 3rd Layer of sand |
|----------------------------|-------------------|-------------------|-------------------|
| Depth (m)                  | 2310.48 - 2326.9  | 2294.17 - 2307.35 | 2265.21 - 2276.24 |
| Thickness (m)              | 16.42             | 13.18             | 11.03             |
| Pressure at layer (MPa)    | 10.45             | 10.38             | 10.25             |
| Maximum pressure (MPa)     | 30.24             | 30.02             | 29.65             |
| Density of CO$_2$ (Kg/m$^3$) | 217.53           | 215.90            | 212.89            |
| Temperature (°C)           | 91.7              | 91.24             | 90.43             |
| Temperature of well (°C)   |                   |                   | 67.78             |
| Porosity (%)               |                   |                   | 16 – 27 %         |
| Permeability (md)          |                   |                   | 69 – 450          |
| Pressure current of well (MPa) |                 |                   | 10.76             |

3. Results and Discussion

3.1 Storage Capacity and Pressure Buildup.

The result of storage capacity is shown in table 2 with the injection rate ranging from 1,000 to 4,000 tons/day. The storage capacity is related with pressure buildup and the amount of injected CO$_2$. Because the amount of injected CO$_2$ results in an increase in pressure. When increasing pressure meets the maximum pressure; then the CO$_2$ injection is stopped and the formation is set to shutin to prevent caprock breaking.

From the results, it is shown that 1st layer can store maximum amount of CO$_2$ from 0.76 to 0.82 Mt because it has a thicker formation and it is located in the deeper formation or higher pressure. Also, the density of CO$_2$ at this formation is higher than other formations. Therefore, this formation can have higher CO$_2$ storage capacity. With these reasons, the best one is 1st layer followed by 2nd and 3rd layers.

Table 2. CO$_2$ Storage capacity in each layer

| The layer of sand | Storage capacity (Mt) |
|-------------------|-----------------------|
| 3rd Layer of sand (Top sand) | 0.36-0.52 |
| 2nd Layer of sand (Middle sand) | 0.48-0.73 |
| 1st Layer of sand (Bottom sand) | 0.76-0.82 |

Moreover, the results of pressure buildup are presented in figures 2 to 4 including the maximum pressure. The results are monitored for the period of 50 years with injection rate from 1,000-4,000 tons/day. Figure 3 is for the period of 50 years. While figure 4 is for the period of the first 10 years of simulation and expands the scale from figure 3. From figure 2, with 1,000 ton/day injection rate, the pressure is gradually increasing until it can meet to the highest pressure but the pressure with 2,000-4,000 ton/day injection rate are sharply increased to the highest pressure without caprock breaking. After shutin time, pressure is little higher for a while and then pressure is gradually decreasing in every injection rates due to the expansion of CO$_2$. The reason is that when CO$_2$ is injected to the formation, it pass through the small pores. Therefore, the effect of pressure buildup becomes gradually increased. When CO$_2$ injection is stopped, the effect is still continues, thus making the pressure going up. However, it continues for short period of time and the pressure falls down as presented in figure 2-4. Other layers have the same trend with the first layer. According to table 1, the second and third
layers have lower maximum pressure at 30.02 and 29.65 MPa, respectively. Therefore, with the same injection rate, they can reach the maximum pressure faster than the first layer.

**Figure 2a.** Pressure buildup of the 1st layer for each injection rate for 50 years

**Figure 2b.** Pressure buildup of the 1st layer for each injection rate for 10 years

**Figure 3a.** Pressure buildup of the 2nd layer for each injection rate for 50 years
3.2 Plume migration

The results of plume migration in all layers at the 1000 ton/day injection rate for 50-year period are shown in figure 5 (a-f). CO₂ migrates both horizontally and vertically. Even CO₂ injection is stopped.
CO₂ migration still continues. Moreover, the velocity of migration is controlled by the degree of the permeability of the formation [11,12]. From the figures, it is clear that CO₂ is injected from the bottom layer. Then CO₂ is arising to the top part of each layer and expand horizontally even though CO₂ injection is stopped. After reaching to highest pressure, the shutin is performed. However, CO₂ is still expanding for a while and decreasing gradually. The results of all layers have the same tendency in every injection rates. The plume migration at injection rate of 1,000 tons/day is expanding to obtain the largest area.

![Plume migration models](image1.png)

**Figure 5.** Models of plume migration for 50-year period at the inject rate of 1,000 tons/day

4. **Summary**

This work is studying the potential of CO₂ storage sites in depleted oil and gas reservoir in the Gulf of Thailand by using 3D simulation model of 3 formations created by CMG program with the various conditions such as injection rate ranging from 1,000 to 4,000 tons/day and 50-year period of CO₂ monitoring. The real field data are obtained and applied to this study such as the formation depth of 2,200-2,330 meters, permeability, and porosity and so on. The behaviour of CO₂ movement, storage capacity, pressure buildup and plume migration are simulated for 50-year period. The results present that pressure is increased until it is close to maximum pressure without caprock breaking and the injection is terminated or shutin. Therefore, CO₂ storage capacities can be calculated. Also, the injection rate of 2,000-4,000 tons/day are increasing sharply meanwhile the injection rate of 1,000 tons/day is gradually increasing. For the plume migration, at the beginning, CO₂ is injected into the
bottom part of each layer and then CO$_2$ is arising to top part because of the density. Then plume migration is expanding horizontally. Plume migration of CO$_2$ is still expanding after shutin time. Therefore, the radius of plume migration can be calculated. This preliminary study can be used as a basic knowledge and applied to the higher level for the CO$_2$ storage in the Gulf of Thailand in the future.

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