Modeling the behavior of CO$_2$ injection in a sand reservoir

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Abstract. Injection CO$_2$ into subsurface formation changes in-situ pore pressure and temperature which in turn alters the effective stress condition. An attempt to analyze the geomechanical responses induced by CO$_2$ fluid injection in a sand reservoir is performed on this study. The objective of this study is to develop Graphical User Interface (GUI) of coupling program code that linking two existing and proven programs, TOUGH2 and FLAC3D, for coupled fluid flow – geomechanics modeling. TOUGH2 is a numerical simulator that solves fluid-flow and transport equation, whilst FLAC3D is a numerical code to simulate geomechanical analysis. Fluid – flow and geomechanical equations are sequentially solved by using finite difference methods. The coupling method used in this paper is two – way coupling where the coupling parameters are transferred from each code in certain time step. The simulation is conducted to know the reservoir behavior geomechanically. The pore pressure, stress alteration and displacement induced by CO$_2$ fluid injection is shown and be analysed. This model could be applied to other field and serve as a basis information for the injection strategy.

1. Introduction
Carbon Capture and Storage (CCS) is one of many methods to reduce amount of CO$_2$ emission in the atmosphere. The CO$_2$ emission can be generated by fossil fuel exploitations, for instance from industrial processes. There are three steps in CCS technology that are CO$_2$ molecule capturing, transportation and CO$_2$ storage. In order to conduct CCS project there are several considerations that must be noted such as the storage, the capacity and the security. In addition, large amount of CO$_2$ emissions produced by the industry activities need large storage capacity. These needs can be tackled by injecting the CO$_2$ fluid into subsurface geological formation. Some factors have to be considered in CO$_2$ injection, such as safety and risk.

CO$_2$ injection into geological formation can cause complex changes in the subsurface such as pressure, temperature, and saturations. The complexities of subsurface systems caused by CO$_2$ injection include thermomechanical, hydromechanical, geomechanical and chemical reactive effects (THMC). CO$_2$ mass injection can alter fluid pressure, temperature, saturation especially around the well injection. CO$_2$ injection process can potentially induce the fault reactivation and CO$_2$ leakage, both during and post-injection. Furthermore, these perturbations will affect to local stress condition and will ultimately
induce mechanical deformation and the possibility of rock failure. Moreover, the rock failure can reactivate existing fracture and also induce new fracture which will reduce the stability of cap rocks.

THMC process in CO$_2$ injection case can be solved by solving coupled numerical equation sequentially by involving coupled parameters. Based on numerical model approaches [1], we develop a Graphical User Interface (GUI) of external program in order to link the fluid flow solver (TOUGH2) and mechanical solver (FLAC3D). Task of the code is mainly to interface all modules required during simulations. Then the code can be utilized to simulate CO$_2$ injection for a simple reservoir model.

2. Methods

TOUGH2 is a numerical simulation program for multi-dimensional fluid and heat flows of multiphase and multi-component fluid mixtures in porous and fractured media [2]. For analyzing multi component, TOUGH2 provides EOS (Equation of State) modules. ECO2M is one of EOS modules in TOUGH2 simulator for modeling CO$_2$ in saline aquifers [3]. TOUGH2 software solves mass and heat balance equation simultaneously by finite difference method.

FLAC3D (Fast Lagrangian Analysis of Continua in 3 Dimensions) software is a numerical method which solves the equation of motion and stress – strain relation of the material uses the finite difference method. The program is used to simulate material behavior due to external loading [4]. Furthermore, FLAC3D is able to represent elastoplastic behavior of materials.

To enhance the capability defined by user, FLAC3D software provides FISH, a language programming which is integrated in FLAC3D. In order to record and retrieve mechanical condition at certain term, The FLAC3D software provides command SAVE and RESTORE. The commands are useful while conducting sequential simulations. The SOLVE command is used to solve the mechanical equilibrium and the calculation process will stop when final solution is reached, which is the balance force approaching zero.

Numerical procedures of complex geomechanical simulation typically use explicit sequential method. Each code program is executed once and coupling parameters are transferred every certain time interval (see Figure 1). In this simulation, the hydraulic properties in TOUGH2 software are calculated as a function of mean effective stress which is output of FLAC3D code. Porosity effective is corrected using relationship with mean effective stress [1] as follows

$$\phi = \phi_r + (\phi_0 - \phi_r) \exp(a \times \sigma'_M)$$  \hspace{1cm} (1)

with $\phi$ is new porosity, $\phi_0$ is porosity at zero stress, $\phi_r$ is porosity at high stress condition, and $\sigma'_M$ is mean effective stress which is calculated as follows,

$$\sigma'_M = \frac{1}{3} (\sigma'_{11} + \sigma'_{22} + \sigma'_{33})$$  \hspace{1cm} (2)

where $\sigma'_M$ is negative in compression. New porosity value is employed to correct permeability value [1] using formula as follows,

$$k = k_0 \exp \left[ c \times \left( \frac{\phi}{\phi_0} - 1 \right) \right]$$  \hspace{1cm} (3)

with $k$ is intrinsic permeability, $k_0$ is intrinsic permeability at zero stress. The $a$ and $c$ constant [Eqs. (1) and (3)] basically should be determined from experimental result that represent the correlation between porosity - permeability change and stress perturbation. In this study, we employ $5.0 \times 10^{-8}$ for $a$ and $22.2$ for $c$ constant which is obtained from [5]. The values represent the correlation with laboratory.
measurements on sandstone presented by Davis and Davis [6]. Capillary pressure is corrected using porosity-permeability relationship according to a Leverett’s function [7] as follows,

$$P_c = P_{c0} \left( \frac{k_0/\phi_0}{k/\phi} \right)$$  

\[ (4) \]

Figure 1. (a) The function of external code and (b) scheme for transfer data of simulator TOUGH2 – FLAC3D [1]

As illustrated in Figure 2(a), subsurface model consists of 4 layers, i.e. Upper Rock, Cap Rock, Aquifer and Basement Rock with thickness of 1.2 km, 0.1 km, 0.2 km and 1.5 km, respectively. The subsurface model has a dimension of 10 km x 10 km x 3 km and is discretized into 24,576 elements (see Figure 2b). In this simulation, CO₂ fluid is injected into aquifer formation at 1.475 km in depth. At this depth, the injected CO2 is expected to be a super-critical fluid due to range of temperature and pressure condition.

Assumptions of subsurface condition and physical properties of rocks for running simulations are taken from previous studies (e.g. [1], [8]). Initial temperature is calculated using geothermal gradient from the surface. The system is assumed have heat conductivity of 1.8 W/m°C and specific heat of 1,500 J/Kg °C [8].

Figure 2. Cross section model with injection well in the middle. (a) Simple geological model and (b) Mesh representation of the simple model
The subsurface model is initiated with hydrostatic pressure condition. At the surface is assumed that pressure condition is 0 MPa, whilst at injection point around 14.5 MPa and lastly at the bottom of the model around 29.4 MPa. The gravitational force is modeled to represent the overburden stress in the model as initial stress condition. Vertical and horizontal stresses around injection point are 32.2 MPa and 19.6 MPa, respectively. At the lateral boundary is assumed that there is no horizontal displacement normal to the boundary \((U_{xx} = U_{yy} = 0)\). In addition, at the bottom boundary is assumed that there is no vertical displacement during simulation \((U_{zz} = 0)\).

| Properties                           | Upper Rock | Cap Rock | Sand Reservoir | Basement Rock |
|--------------------------------------|------------|----------|----------------|---------------|
| Young’s Modulus (GPa)                | 5          | 5        | 5              | 5             |
| Poisson’s Ratio, \(v\) (dimensionless) | 0.25       | 0.25     | 0.25           | 0.25          |
| Biot’s parameter, \(a\) (dimensionless) | 1          | 1        | 1              | 1             |
| Saturated rock density, \(\rho_s\) (Kg/m³) | 2,260      | 2,260    | 2,260          | 2,260         |
| Zero stress porosity, \(\Phi_0\)(dimensionless) | 0.1        | 0.01     | 0.1            | 0.01          |
| Residual porosity, \(\Phi_r\)(dimensionless) | 0.09       | 0.009    | 0.09           | 0.009         |
| Zero stress permeability, \(k_0\)(m²) | 1 x 10⁻¹⁵  | 1 x 10⁻¹⁷| 1 x 10⁻¹³      | 1 x 10⁻¹⁷     |
| Irreducible gas saturation for Corey [9], \(S_{rg}\)(dimensionless) | 0.05       | 0.05     | 0.05           | 0.05          |
| Irreducible gas saturation for Corey [9], \(S_{rg}\)(dimensionless) | 0.3        | 0.3      | 0.3            | 0.3           |
| Van Genuchten’s air-entry pressure [10], \(P_0\) (Kpa) | 196        | 3,100    | 19.6           | 3,100         |
| Van Genuchten’s exponent [10], \(\lambda\) | 0.457      | 0.457    | 0.457          | 0.457         |

3. Results and Discussions

In this paper we model and simulate the CO2 fluid injection at the depth of 1.475 km with rate of 10 Kg/s. Shortly after CO2 fluid injection, CO2 fluid will migrate laterally and vertically. Fluid compositions around injection point will be mixture of existing fluid and CO2 fluid injection. Figure 3 illustrates cross plot between pore pressure (in MPa) versus depth (in meter) for different time of injection. It can be seen in Figure 3 that after several hours injection time the pore pressure around injection point is high due to CO2 fluid accumulation. The change in fluid mass and pore pressure condition alter the local stress condition around the injection point. The stress alteration of the rock might then induce rock mass deformation.
Figure 3. Cross plot of pore pressure evolution (MPa) versus depth (m).

Figure 4 shows 3D model of vertical displacement due to alteration in CO$_2$ fluid accumulation after 2.52 and 22.2 hours of injection. It can be seen that the difference in vertical displacement around the injection well after 2.52 and 22.2 hours of injection is significant. CO$_2$ injection simulation using this simulator into a more complex geological model is ongoing undertaken. Moreover, existing geological structure (e.g., fault and fracture) and permeability anisotropy should be incorporated in simulation to give more knowledge about behavior of CO$_2$ fluid injection in the reservoir.

Figure 4. Contour of vertical displacement (m) after (a) injection for 2.52 hours and (b) injection for 22.21 hours.
4. Conclusions
The external code made in this study to couple two existing software in order to simulate coupled THM process in CO₂ fluid injected has been successfully implemented for a simple reservoir model. The anomalous high pore pressure around injection point is introduced due to CO₂ fluid accumulation. This condition will impact the local stress around injection point. The change of local stress condition leads to rock deformation and possibility rock failure which would reduce the ability of cap rock. Eventually this code is implemented to simulate injection of CO₂ as part of CCS Pilot projects in Gundih field [11].

Acknowledgements
Writers thank to the SATREPS project by JICA – JST, Bandung Institute of Technology and Kyoto University for this research. We also thank to Kyoto University for providing software training for four weeks in Kyoto, Japan.

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