Modeling geomechanical responses induced by CO2 injection in CCS pilot project in Gundih field, Indonesia

Fatkhani, Cahli Suhendi, David P Sahara, Mohammad Rachmat Sule

1Seismology, Exploration and Engineering Research Group, Faculty of Mining and Petroleum Engineering, Institut Teknologi Bandung, Indonesia
2Geophysical Engineering, Department of Sciences, Institut Teknologi Sumatera, Indonesia
3Global Geophysics Research Group, Faculty of Mining and Petroleum Engineering, Institut Teknologi Bandung, Indonesia

*E-mail: fatkhan@yahoo.com

Abstract. Injection activity changes reservoir pore pressure and temperature condition and then alters stress condition of reservoir. Increasing pore pressure from injection leads to a decrease in effective stress of reservoir rocks and surrounding rocks. It induces deformation and failure on the reservoir, which in turn, might create surface uplift. This process is modelled by a coupled Thermo – Hydro – Mechanics (THM) modelling. Hence, objective of study is to investigate and to simulate geomechanical responses induced by CO2 injection in Gundih Field, as part of Carbon Capture and Storage (CCS) Pilot Project in Indonesia. A 3D model of a layered formation consists of porous and permeable reservoir layer and non-porous and impermeable cap rock is built. A boundary condition is set as no lateral displacement normal to side boundary and no vertical displacement normal to bottom boundary. An injection scheme of 0.32 Kg/s for one year is applied in the reservoir at 900m depth. At this depth, CO2 is a supercritical condition, in which the pressure distribution obtained in this study showed that the stress perturbation around the cap rock due to CO2 fluid injection is relatively small and no failure at the cap rock layer is expected. Hence, the proposed CO2 fluid injection is safe to be executed. The program developed in this study could be used to assess the design of CO2 injection schemes.

1. Introduction

As we know that fossil fuel exploitations, such as electric generation, and industrial process are responsible for CO2 emission in the atmosphere. In order to decrease amount of the CO2 emission, Carbon Capture and Storage (CCS) is one of many methods developed to reduce it. The CCS method consists of several activities, such as capturing CO2 molecules, transporting CO2 and storing CO2 into subsurface formation. The subsurface formation is one of solutions for the storage that often need to provide a large storage capacity.

At first the capacity and security of the storage reservoir must be analyzed in order to reduce risk factors. The security and leakage risk factors are the paramount consideration of the CCS operation. This is simply because CO2 injection process has possibility to reactivate the existing faults. In addition, CO2 leakage to the underground water can also cause environmental hazards. A phenomenon of the CO2
leakage can occur in both during injection and post-injection processes. Those problems arise due to the fact that the injection process to some degree can alter reservoir pore pressure and temperature conditions. Increasing pore pressure due to CO$_2$ injection will induce to a decrease of effective stress for both reservoir rocks and surrounding rocks. This can disturb the stress condition of the reservoir. These will affect the hydraulic properties of rocks, such as porosity, permeability capillary pressure.

In this paper, we attempt to simulate and model coupled fluid flow and geomechanical analysis in terms Thermo – Hydro – Mechanical (THM) process for “Gundih CCS project” in Indonesia. Gundih CCS project, if successfully run, can be regarded as the first CCS pilot project in Indonesia. The project is devoted for research and development of CCS technologies. In line with that, Indonesian’s government has also a plan to reduce CO$_2$ more than 20% by 2020 [1]. One of many technologies developed to reduce CO$_2$ emission in the atmosphere is by injecting CO$_2$ into subsurface formation. Hopefully, it can be successfully implemented in Gundih gas field, Central Java (e.g. [1], [2], [3]).

![Figure 1. Location map of Gundih Field, Indonesia. It is located in a sedimentary basin located at the back arc [4]](image)

As seen in Figure 1, Gundih gas field is a back – arc basin which is located at the surround of the east Java basin [2]. A fault is existed and can be observed in surrounding area which is extended from NE to SW around the Gundih gas field [2]. This fault is likely has a potential impact to CO$_2$ fluid injection process. Finding from geological studies concludes that Ngrayong Formation is the most possible candidate to be the storage formation. Hence, the CO$_2$ fluid is planned to put into Ngrayong formation at the depth around 800 m. Based on theoretical calculations, at the depth regarding to the temperature and pressure condition CO$_2$ fluid should be in supercritical condition [2]. Tsuji, et al., [2] shows that the pore pressure condition at the Ngrayong formation is almost at hydrostatic condition. A strong heterogeneity of hydrological and physical properties of the Ngrayong formation is observed between northern and southern region. Based on the permeability test conducted by ITB and JICA team at the outcrop samples, it is concluded that the permeability of the northern Ngrayong formation is higher than the southern one [3]. Wonocolo formation is shallower than Ngrayong formation and the rock samples obtained from this lithology have low permeability [2] (see lithology and formations in Figure 2). Hence, we consider this as a seal layer.
The previous GGR (Geology-Geophysics and Reservoir) study in the area found that JEPON–1 well is the most reliable candidate for CO\textsubscript{2} injection process in Gundih field. One of many reasons is coming from the sidewall core samples of the well, which shows that the Ngrayong sandstones intersected by this borehole are well sorted. This indicates a high permeability sandstone which is suitable for injection purpose [2].

| Formation  | Vp (m/s) | Vs (m/s) | Rho (kg/m\textsuperscript{3}) | Poisson Ratio | G (Gpa) | Bulk Modulus K (Gpa) | Young's Modulus E (Gpa) |
|------------|----------|----------|-------------------------------|--------------|---------|---------------------|------------------------|
| Ledok       | 2,147    | 1,240    | 2,009                         | 0.25         | 3.09    | 5.15                | 7.72                   |
| Wonocolo    | 2,742    | 1,583    | 2,273                         | 0.25         | 5.70    | 9.50                | 14.25                  |
| Ngrayong    | 3,008    | 1,737    | 2,417                         | 0.25         | 7.29    | 12.16               | 18.24                  |
| Tawun/Tuban | 3,295    | 1,902    | 2,495                         | 0.25         | 9.03    | 15.05               | 22.58                  |

In this study, we applied for the first time the code developed in the previous study [6] in a real case. Cahli et al. [6] created external program to link two existing codes, TOUGH2 fluid – flow simulator and FLAC3D geomechanical simulator. Through this study, the planned injection strategy in Gundih CCS field is tested in order to check the safety of the operation. The pore pressure propagation is modeled and the reservoir stability is tested.

2. Modeling
TOUGH2 is a numerical simulator that solves fluid flow and transport equation (e.g. [7], [8]). FLAC3D is a numerical code to simulate geomechanical analysis [9]. Numerical procedure of geomechanical simulation use explicit sequential method which each code is invoked once and the coupled parameter data is transferred on a certain time interval (Figure 3).
CO₂ fluid injection can change conditions of pore pressure (P) and temperature (T). Then the geomechanical simulator calculate stress alteration induced due to parameter change. The change in the in-situ stress condition will affect to rock deformation which, ultimately, alter the hydraulic properties of rock.

As seen in Figure 3, a conceptual subsurface model is derived mainly from GGR study used to simulate CO₂ injection. A 3D model with a dimension of 3x3x2 km is made from rectangular grids. The reservoirs are sand layers which has high porosity and high permeability. The permeability assumed in this simulation is anisotropic permeability with vertical to horizontal permeability ratio is 3. The cap rock layer is assumed to be the clay formation. The layers in subsurface model from top to bottom are shallow overburden, cap rock, reservoir and basement rock with a thickness of 467 m, 349 m, 676 m and 508 m, respectively. At the reservoir depth CO₂ is assumed in a supercritical condition.

![Figure 3. Conceptual model setup for the simulation](image)

As illustrated in Figure 4, boundary condition is used in this numerical modeling. A fixed boundary condition at the side and bottom boundary is used. The gravitational force is modeled to represent the overburden stress in the model as an initial stress condition.

| Properties                              | Shallow overburden | Cap Rock | Reservoir (Sand) | Reservoir (Shale) | Basement Rock |
|-----------------------------------------|--------------------|----------|------------------|-------------------|---------------|
| Biot’s parameter, α (dimensionless)     | 1                  | 1        | 1                | 1                 | 1             |
| Zero stress porosity, Φ₀ (dimensionless)| 0.1                | 0.01     | 0.3              | 0.01              | 0.01          |
| Residual porosity, Φₚ (dimensionless)   | 0.09               | 0.009    | 0.29             | 0.009             | 0.009         |
| Zero stress permeability, k₀ (m²)       | 1 x 10⁻¹⁵          | 1 x 10⁻¹⁷| 3.26 x 10⁻¹³     | 3.26 x 10⁻¹⁵     | 1 x 10⁻¹⁷     |
| Irreducible gas saturation for Corey [10], S₉ₒ (dimensionless) | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 |
| Irreducible gas saturation for Corey [10], S₉ₚ (dimensionless) | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 |
| Van Genuchten’s air-entry pressure [11], P₀ (Pa) | 196 | 3,100 | 19.6 | 3,100 | 3,100 |
| Van Genuchten’s exponent [11], λ | 0.457 | 0.457 | 0.457 | 0.457 | 0.457 |
Several assumptions are made for subsurface condition and physical properties of rocks in order to calculate the conceptual model. An initial temperature is estimated by implementing gradient to temperature at the surface. In addition, the system is assumed has thermal conductivity $1.8 \text{ W/m°C}$ and specific heat $1.500 \text{ J/Kg°C}$ [12]. The subsurface model is initialized with hydrostatic pressure condition. CO$_2$ fluid is injected into reservoir with flow rate of 0.32 Kg/s at the depth deeper than 900 m.

![Figure 4. Geomechanical boundary condition used for the simulation](image)

3. Results and Discussions

There are two important aspects in CO$_2$ storage. First is CO$_2$ leakage related to cap rock integrity. Secondly is CO$_2$ fluid injection might prevail earthquakes. It is also important to note that we have to evaluate the effects of pore pressure change due to CO$_2$ fluid injection. The change in pore pressure condition can affect stress state condition. Eventually this will change hydraulic properties of rock and induce rock deformation.

At first, the initial condition of the in-situ stresses is established and modeled, i.e. principal vertical, maximum horizontal and minimum horizontal stress. This stage is, namely, a static model. Then, the injection is simulated by gradually increasing pressure in the open hole section of the well at the reservoir. The pressure is smoothly increase by CO$_2$ fluid injection. Afterward, deformations, stress perturbation and the possible failures in the reservoir due to injection are analyzed.

![Figure 5. Vertical displacement around injection point after 9 days injection (A), vertical displacement around injection point after 27 days injection (B)](image)

Figure 5 (A) and Figure 6 (B) illustrate vertical displacement induced by CO$_2$ fluid injection after 9 days and 27 days, respectively. It can be seen in the Figures that vertical displacement is still concentrated around the injection point. The pressure diffusion area is still less than 1 km with the uplift of less than 0.00007 m after 9 days and less than 0.0002 m after 27 days injection.
From this simulation, we show that the stress perturbation around the cap rock due to CO$_2$ fluid injection is relatively small. No failure at the cap rock layer is observed. Hence, the proposed CO$_2$ fluid injection is safe to be executed. The reservoir simulation is very important to procedures in CO$_2$ geological storage project, because we can evaluate movement of the injected CO$_2$ within the reservoir. If this study is scaled up from a pilot project into a demonstration or even a commercial project, the maximum amount of CO$_2$ that can be injected also increase with longer injection time.

4. Conclusions

Significant findings can be pointed out in this study are:

- The code developed successfully simulated the mechanical processes of CO$_2$ fluid injection into simplified Gundih Field subsurface model.
- The injection scheme generates approximately 0.0002 m vertical displacement around the injection area after 27 days of injection. At this rate, the deformation is still in the elastic regime and no new fracture creation is expected.
- Therefore, the injection scheme proposed in Gundih CCS field, injection rate of 0.32 Kg/s at a depth of around 900 m for one year, is safe to be applied in Gundih CCS field.
- The information of CO$_2$ distribution in reservoir is important to realize effective (low-cost) CO$_2$ storage, because we can use the information in the design of CO$_2$ injection wells.

References

[1] Kadir W G A, Sule R, Alawiyah S, Setianingsh, Santoso D, Widarto DS, Tamba R, Aasongko D, Widianto E, Matsuoka T 2012 Proceedings of PITHAGI.
[2] Tsuji T, Matsuoka T, Takahashi T, Kitamura K, Onishi K, Yamada Y, Sule MR, Kadir WGA, Widarto DS, Sebayang RI, Prasetyo A, Priyono A, Widianto E, Sapiie B. 2014 Reservoir characterization for site selection in the Gundih CCS project, Indonesia, Energy Procedia 63 pp 6335 – 6343.
[3] Kitamura K, Yamada Y, Onishi K, Tsuji T, Chiyonobu S, Sapiie B, Bahar A, Danio H, Muhammad A, Erdi A, Sari VM, Matsuoka T, Kadir WGA. Gundih CCS project team 2014 Potential Evaluation of CO2 Reservoir Using the Measured Petrophysical Parameter of Rock Samples in the Gundih CCS Project, Indonesia, Energy Procedia 63 pp 4965 – 4970.
[4] Sapiie, B, Danio, H, Priyono, A, Asikin, A R, Widarto, D S, Widianto, E, Tsuji, T 2015 Geological Characteristic and Fault Stability of the Gundih CCS Pilot Project at Central Java, Indonesia, Proceedings of the 12th SEGJ International Symposium.
[5] Asikin, A, Sule, R, Priyono, A, Tsuji, T, Raharjo, S 2015 Simulation of time lapse seismic for CO2-injection monitoring: preliminary result, Proceedings of the 12th SEGJ International Symposium.
[6] Suhendi C, Sahara P David, Fatkhan, Sule M.R 2017 Modelling the behavior of CO$_2$ injection in a sand reservoir, Proceedings of APS 2017.
[7] Pruess, K, Oldenburg, C and Moridis, G 1999 TOUGH2 USER’S GUIDE, VERSION 2.0, Earth Sciences Division, Lawrence Berkeley National Laboratory (Berkeley : University of California).
[8] Pruess, K 2011 ECO2M: A TOUGH2 Fluid Property Module for Mixtures of Water, NaCl, and CO2, Including Super- and Sub-Critical Conditions, and Phase Change Between Liquid and Gaseous CO2 Earth Sciences Division, (Berkeley : Lawrence Berkeley National Laboratory University of California).
[9] Itasca Consulting Group Inc. 2009 FLAC3D manual (Minnesota, USA).
[10] Corey A T 1954 The interrelation between oil and gas relative permeabilities Producers Monthly Nov. 1954 38 – 41
[11] van Genuchten M T 1980 A closed – form equation for predicting the hydraulic conductivity of unsaturated soils Soil Sci. Soc. Am. J. 44 892 - 898
[12] Miguel-Martinez, G J G 2014 A Hydromechanically-based Risk Framework for CO2 Storage Coupled to Underground Coal Gasification, Ph.D Thesis (Newcastle: University of Newcastle).