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## **Thermal Effects on Shear Fracturing and Injectivity During CO<sub>2</sub> Storage**

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Additional information is available at the end of the chapter

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### **Abstract**

With almost two hundred coal burning power plants in Ohio River valley, this region is considered important for evaluation of CO<sub>2</sub> storage potential. In a CO<sub>2</sub> storage project, the temperature of the injected CO<sub>2</sub> is usually considerably lower than the formation temperature. The heat transfer between the injected fluid and rock has to be investigated in order to test the viability of the target formation to act as an effective storage unit and to optimize the storage process. In our previous work we have introduced the controversial idea of injecting CO<sub>2</sub> for storage at fracturing conditions in order to improve injectivity and economics. Here we examine the thermal aspects of such process in a setting typical for Ohio River Valley target formation.

A coupled flow, geomechanical and heat transfer model for the potential injection zone and surrounding formations has been developed. All the modeling focuses on a single well performance and considers induced fracturing for both isothermal and thermal injection conditions. The induced thermal effects of CO<sub>2</sub> injection on stresses, and fracture pressure, and propagation are investigated. Possibility of shear failure in the caprock resulting from heat transfer between reservoir and the overburden layers is also examined.

In the thermal case, the total minimum stress at the wellbore decreases with time and falls below the injection pressure quite early during injection. Therefore, fracturing occurs at considerably lower pressure, when thermal effects are present. The coupled thermal and dynamic fracture model shows that these effects could increase the speed of fracture propagation in the storage layer depending on the injection rate. These phenomena are dependent primarily on the difference between the injection and reservoir temperature.

Our results show that shortly after injection, the induced expansion in caprock lead to slight increase of total stresses (poroelasticity) which will reduce the chance of shear failure. However as soon as total minimum stress in the caprock decreases due to thermal diffusion between the reservoir and caprock, thermoelasticity dominates and the chance of shear failure increases in the caprock.

Incorporation of thermal effects in modeling of CO<sub>2</sub> injection is significant for understanding the dynamics of induced fracturing in storage operations. Our work shows that the injection capacity with cold CO<sub>2</sub> injection could be significantly lower than expected, and it may be impractical to avoid induced fracture development. In risk assessment studies inclusion of the thermal effects will help prevent the unexpected leakage in storage projects.

## 1. Introduction

Past storage pilot projects and enhanced oil recovery efforts have shown that, geologic sequestration of CO<sub>2</sub> is a technically viable means of reducing anthropogenic emission of CO<sub>2</sub> from accumulating in the atmosphere [1,2,3]. Security of storage is one of the most important concerns with the long term injection of CO<sub>2</sub> in underground formations. Injection of CO<sub>2</sub> induces stress and pore pressure changes which could eventually lead to the formation or reactivation of fracture networks and/or shear failure which could potentially provide pathways for CO<sub>2</sub> leakage through previously impermeable rocks [4]. Therefore geomechanical modeling plays a very important role in risk assessment of geological storage of CO<sub>2</sub>.

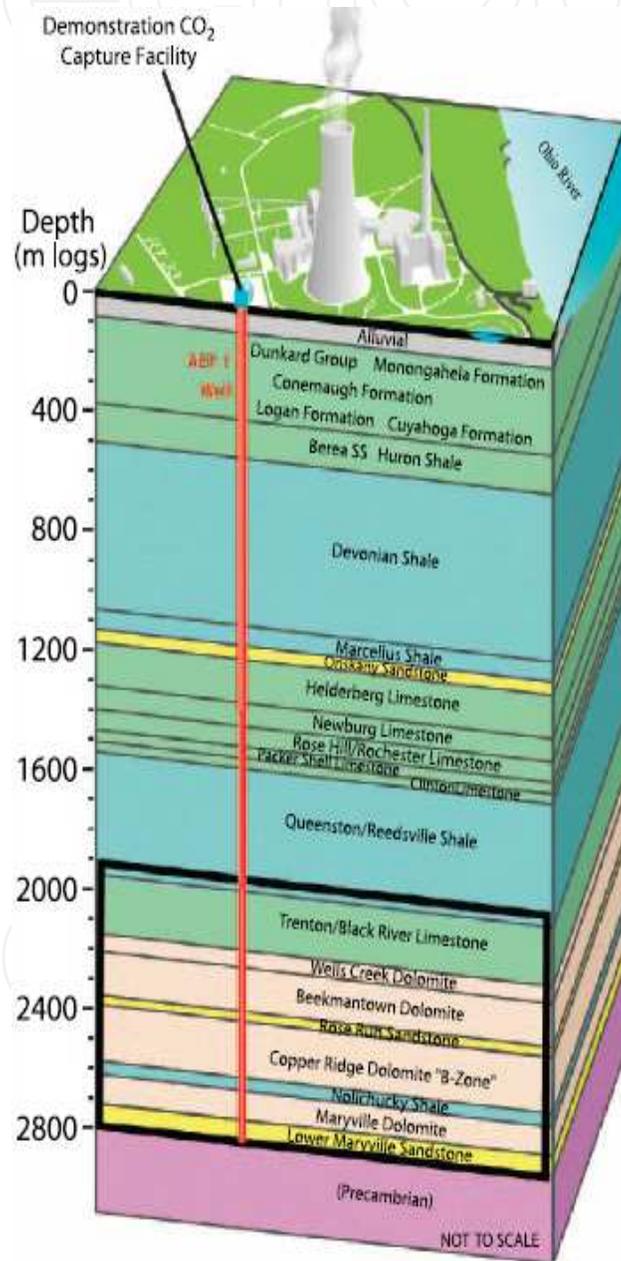
In order to determine whether the induced stress changes compromises the ability of the formation to act as an effective storage unit, a geomechanical assessment of the formation integrity must be carried out. In our previous work, we have studied the dynamic propagation of fracture in the Rose Run sandstone reservoir in Ohio River valley under isothermal [5] and thermal condition [6] for injection above fracture pressure. In this paper, the thermal effect of injection on the possibility of tensile and shear failure in the reservoir and caprock are studied for injection below fracture pressure. This study utilized a fully coupled reservoir flow and geomechanical model which allows accounting for poroelastic and thermoelastic effects and can model static and/or dynamic fractures.

To examine the possibility of shear failure in the caprock, Mohr-Coloumb Criteria was used.

## 2. Construction of the flow, thermal and geomechanical model

A coupled flow, thermal, and geomechanical model has been developed in order to study the thermo-elastic and poro-elastic response of the injection and surrounding layer to increasing of pressure and reduction of temperature after CO<sub>2</sub> injection. Ohio River valley is located in a relatively stable, intraplate tectonic setting and the regional stress state is in strike slip faulting regime with the maximum stress oriented northeast to east-northeast [7].

This study used the fluid and rock mechanical properties provided by Lucier et al. [8]. The stratigraphic sequence of the geological layers in the study area and the relative location of the potential injection layer, Rose Run Sandstone (RRS) at the Mountaineer site is shown in Figure 1. RRS has an average thickness of 30 m and is extended from 2355-2385 m. The direction of maximum and minimum horizontal stresses is reported to be in N47E( $\pm$ 13) and N43W ( $\pm$ 13) respectively [8]. All the models in this study are aligned along these directions, in order to avoid having initial non-zero value of shear stresses in principal stress directions.



**Figure 1.** Generalized stratigraphy of the study area at the Mountaineer site. The well location and the general stratigraphy intersected by well is illustrated in the picture. The black box shows the boundaries of the area of previous work by Lucier et al., [8], Modified from [9]

The developed element of symmetry model that covers 8000x8000x2575 m of study area, has 50x50x9 grid block in x, y and z directions respectively. The injection well is located at the top left corner of this model. RRS was gridded into three layers with 5, 10 and 15 m thickness. The adjacent Beekmantown Caprock was refined into 3 layers (10, 50 and 126 m) to capture and predict the potential growth of fracture through this layer (and the resulting possibility for CO<sub>2</sub> leakage). The horizontal and vertical permeability of the caprock layers in the model are given as 2E-10 and 1E-10 md respectively. Average properties of 5%, 20 md and 10 md for porosity, horizontal and vertical permeability were given to the injection layer. These values are the probability averages of the given property distributions for Rose Run sandstone formation [8]. The initial pressure and temperature of the RRS is 26000 kPa and 63.1 C. The fluid flow is modeled by two-phase flow with dissolution of CO<sub>2</sub> in water. Van Genuchten function with an irreducible gas saturation of 0.05, an irreducible liquid saturation of 0.2 and an exponent of 0.457 was used to generate relative permeability data [10].

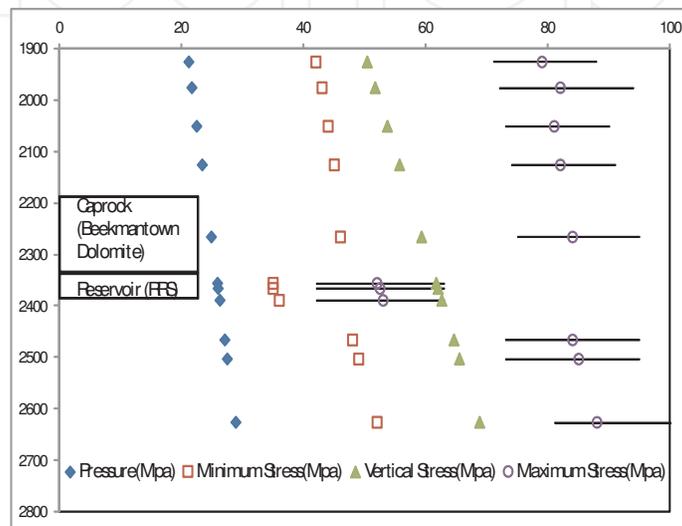
The mechanical properties and initial stress profile is required to be added to the geomechanical model and coupled with the flow model in order to be able to study the mutual effect of pressure and stresses and the resulting effect on fracture propagation and injectivity. The mechanical properties for this model are listed in Table 1. The listed value with the exception of grain Modulus are all extracted directly from Lucier et al. paper [8]. Grain modulus was back-calculated from the given Biot constants and Young's Modulus. The Biot constant  $\alpha$  is important for computing the effects of pressure changes on stress. At the Mountaineer site, Lucier et al. estimated  $\alpha$  to be very low - in the range of 0.03 to 0.2. In this analysis, a mean value of 0.11 was used to calculate the poroelastic effects. The formation rock density is assumed to be 2500 kg/m<sup>3</sup> [8].

Layer-top depth (m)	Thickness (m)	Young's Modulus (kpa)	Poisson's Ratio	Grain Modulus (Kpa)
Shale-Surface	1911	6.00E+07	0.29	5.25E+07
Limestone-1911	253	7.05E+07	0.3	6.61E+07
Dolomite-2164	186	8.96E+07	0.28	7.51E+07
Rose Run Sandstone-2350	30	8.73E+07	0.25	6.53E+07
Dolomite-2380	195	9.47E+07	0.28	8.05E+07

**Table 1.** Rock Mechanical properties of the coupled model

The initial pressure, horizontal and vertical stress profile for different depths in Ohio River Valley is shown in Figure 2. It is important to note that the horizontal stresses are lower in RRS (the injection layer) than in the surrounding layers. This is a common behavior due to generally having larger Poisson's ratio for the surrounding layers than the reservoir. In many situations the stresses in caprock (low permeability rock) are larger than in the reservoir (permeable formations), because of differences in Poisson's ratio, material properties, stress history and other factors. This is well documented in hydraulic fracturing literature and is the primary

mechanism for containment of fractures to the target zone. This initial stress contrast is very critical when considering fracture propagation in the reservoir layer for enhancing injectivity while avoiding the risk of fracture growth through upper caprock layers. As mentioned before, since the temperature of injected CO<sub>2</sub> (at approximately 30 deg C) is smaller than the formation temperature (at 60 deg C), thermal effects of injection on fluid flow and geomechanics must be included in the model. This coupling is achieved by solving the energy balance equation within the fluid flow model, and including the thermoelasticity term in the geomechanical model (included in the constitutive model of the rock).



**Figure 2.** Initial pressure, horizontal and vertical stress profile in Ohio River Valley [8]

The average thermal properties for the rock, as well as injected and in-place fluids used for this study are listed in Table 2 [8,11-14].

	Rock	Water	CO <sub>2</sub>
Volumetric Thermal Expansion Coefficient (1/deg K)	5.4E-6	2.1E-4	3.003E-3
Heat Capacity(Kj/Kg deg K)	0.9	4.182	0.84
Thermal Conductivity(W/ m deg K)	2.34	0.65	0.084

**Table 2.** Thermal properties of fluids and rock

The boundary condition for the fluid flow model is that there is no flow across the boundary of the model. The constraints for the geomechanical model are as follows. The right and left sides of the model are fixed in the x-direction so there would be no displacement in the x-direction. The front and back sides of the model are fixed in Y direction. The bottom side of the model is fixed in vertical direction and the top of the model is free to move in all directions. Stresses were initialized according to data in Fig. 2. All injections are done through a single vertical well with constant injection rate.

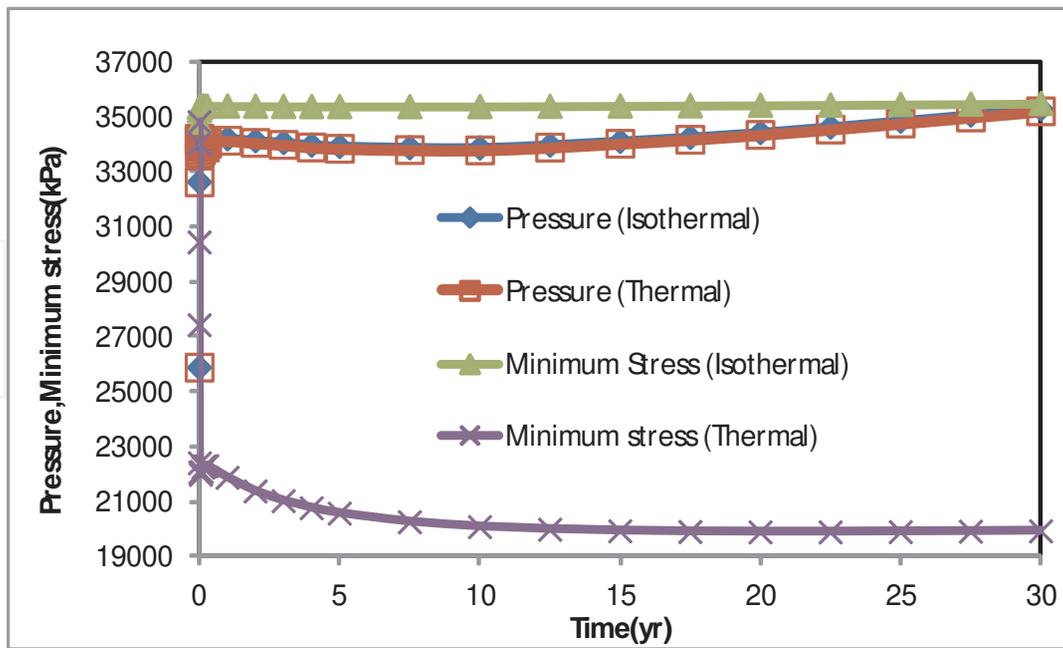
### 3. Thermal fracturing in the reservoir below isothermal fracture pressure

Thermal effects of CO<sub>2</sub> injection is expected to affect the magnitude of displacements, pressure, stresses, and the possibility of shear and tensile failure in the reservoir and caprock. Injecting fluid with temperature lower than reservoir rock temperature will cause reduction of stresses in the injection layer and once the temperature front has reached a relatively large area around the wellbore, this reduction in stresses will result in negative volumetric strains that can propagate to the surface. Therefore the surface displacement for the thermal model would be smaller than that of isothermal model [6].

One of the most important effects of injecting a fluid with a lower than reservoir temperature is the reduction of fracture pressure. Cooling of the formation rock during injection of cold CO<sub>2</sub> through thermal conduction and convection lowers the total stresses in the reservoir and possibly caprock layer. This results in reduction of fracture pressure and the pressure differential available for injection, and therefore injectivity. In the case of injection at fracturing conditions, the fracture propagation pressure will decrease and, if the same injection rate is used, this will accelerate fracture propagation.

In order to examine thermal effects of injection on the possibility of reaching tensile failure in the reservoir, the variation of total stress and pressure needs to be studied. In order to do that, the coupled geomechanical, flow and thermal simulation has been carried out with two different injection temperatures. The injection of CO<sub>2</sub> for these models is through a single vertical well with constant rate of 3.4E4 m<sup>3</sup>/day such that the bottomhole pressure will remain below fracture pressure for the isothermal model during 30 years of injection. It should be noted that fracturing was not allowed in these models. Thermal model in this study refers to injection temperature (30 C) being lower than the reservoir temperature (60 C), while in the isothermal model, it is equal to reservoir's temperature. Figure 3 shows the modeling results for pressure, and total minimum stress for well block in the reservoir during 30 years of injection for the thermal and isothermal model. As it is seen in Figure 3, the total stress falls below the bottomhole pressure (fracture pressure) for the thermal model in the reservoir at quite early injection times which means that minimum effective stress will reduce beyond zero. Therefore, although CO<sub>2</sub> is injected below the original fracture pressure, fracture would initiate in the reservoir for the thermal case. Since fracturing is not allowed in these models, the stress magnitudes after the onset of fracturing are not valid. If propagation was allowed, minimum total stress would reduce to slightly below bottomhole pressure such that the effective stress on the fracture wall would remain close to zero.

In order to study the thermal effects of injection on the propagation of the induced fracture, for the next set of model cases we allowed fracture propagation in all layers. To model the potential fracture propagation, a transmissibility multiplier technique is incorporated in the model, which essentially accounts for the fluid flow transmissibility through the fracture by a transmissibility multiplier function, specified as a table. The multiplier is calculated from an estimated fracture opening of a 2-D Griffith crack [15] based on the mechanical properties of the injection zone and an estimate of the fracture height [5]. This function can be incorporated



**Figure 3.** Pressure, minimum stress, and stress level for the thermal and isothermal model for the well block in the reservoir's top layer

in the model both as a function of pressure or effective minimum stress. The actual fracture geometry can be calculated by the coupled model.

Figure 4 shows the bottomhole pressure and fracture length for the reservoir's top layer for the thermal and isothermal model. As expected, since the bottomhole pressure remains below the fracture pressure for the isothermal model, there is no fracture initiation in the reservoir for the isothermal model. However since minimum effective stress reduces beyond zero in the thermal model (thermoelastic effects), fracture initiates and propagates through reservoir to a half length of 250 m. The bottomhole pressure in the thermal model is now significantly different. For the thermal model, it increases to fracture initiation pressure (equal to the thermally reduced minimum total stress) and then remains almost constant for the injection period. However for the isothermal model, the pressure history is the same as in Fig. 4.

Figure 5 shows the fracture length, pressure and temperature profile for the well block in the reservoir's top and bottom layer. The results show that under thermal conditions, fracture propagates to a larger extent in the lower reservoir layers than the top ones. As seen in the Figure, the pressures in the reservoir's top and bottom layers are very close. However, the temperature in the bottom of the reservoir is significantly lower than in the top. This results in higher reduction of minimum total stress and lower fracture pressure for the reservoir's bottom layer. This effect can also be clearly seen in Figure 6 which shows the permeability multiplier, temperature and pressure profile in fracture plane near the wellbore (zoomed to 300 m) across reservoir layers. As seen the temperature reduction and permeability multipliers are higher in the bottom layer.

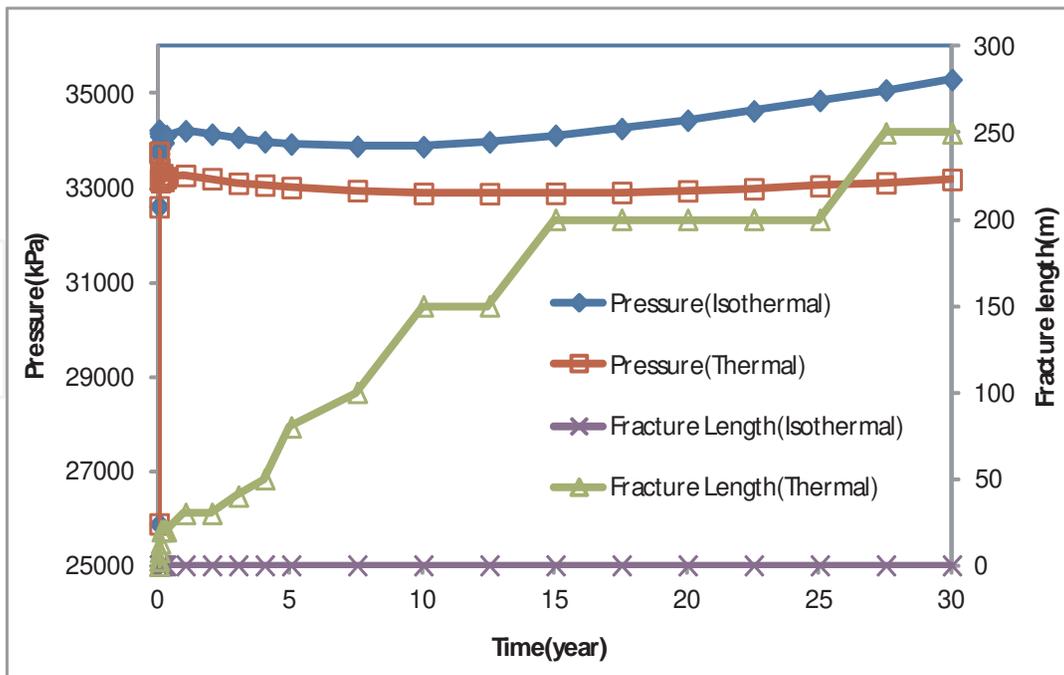


Figure 4. Bottomhole pressure and fracture length for the reservoir's top layer for the thermal and isothermal model

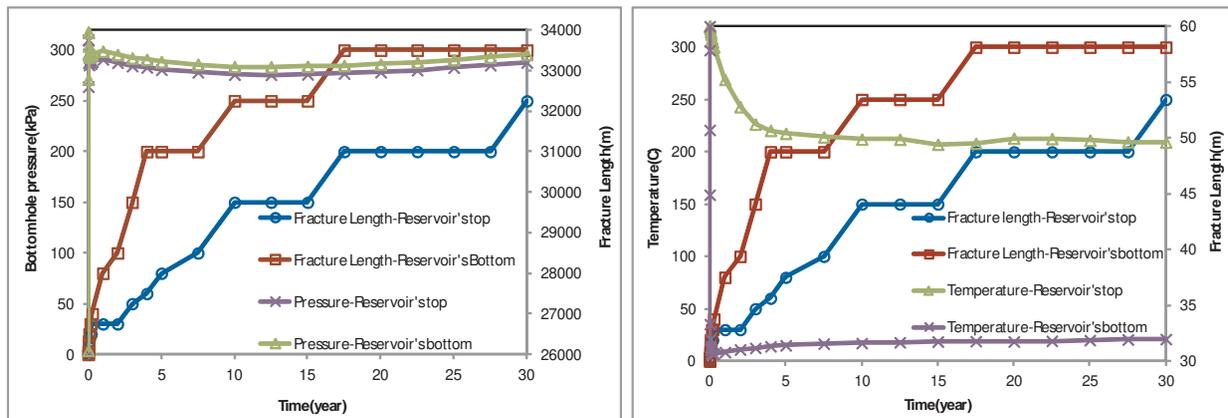
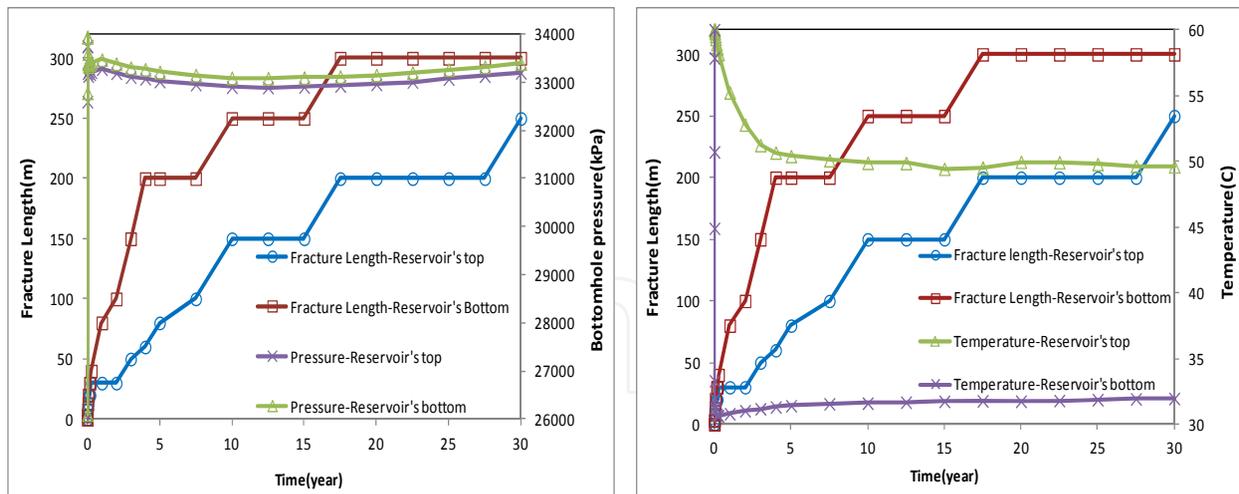


Figure 5. Fracture length and pressure profile (left), fracture length and temperature profile (right) for the reservoir's top and bottom layer

#### 4. Thermally induced shear failure in the caprock

The thermally induced reduction of minimum stress in the caprock could lead to tensile or shear failure of the formation rock which could cause tensile fracture propagation through these layers or hydraulic communication through shear fractures. If there is no stress contrast between the caprock and reservoir, reaching tensile failure in the caprock is possible for injection above fracture pressure [16]. In this study, since the horizontal stresses in the caprock



**Figure 6.** Permeability multiplier(top), Temperature(middle), Pressure distribution (bottom) after 30 years of injection for the reservoir layers

are significantly larger than in the reservoir, tensile fracturing in the caprock is of low likelihood. However given the large initial deviatoric stress in the caprock, the chance of reaching shear failure due to thermally induced stresses is high. In order to evaluate the possibility of reaching shear failure, we have used the Mohr-Coloumb criteria and studied the variation of "Stress level",  $l_{\sigma}$  in the caprock during injection. Stress level is defined as the ratio of deviatoric stress at the current condition to the deviatoric stress at failure condition:

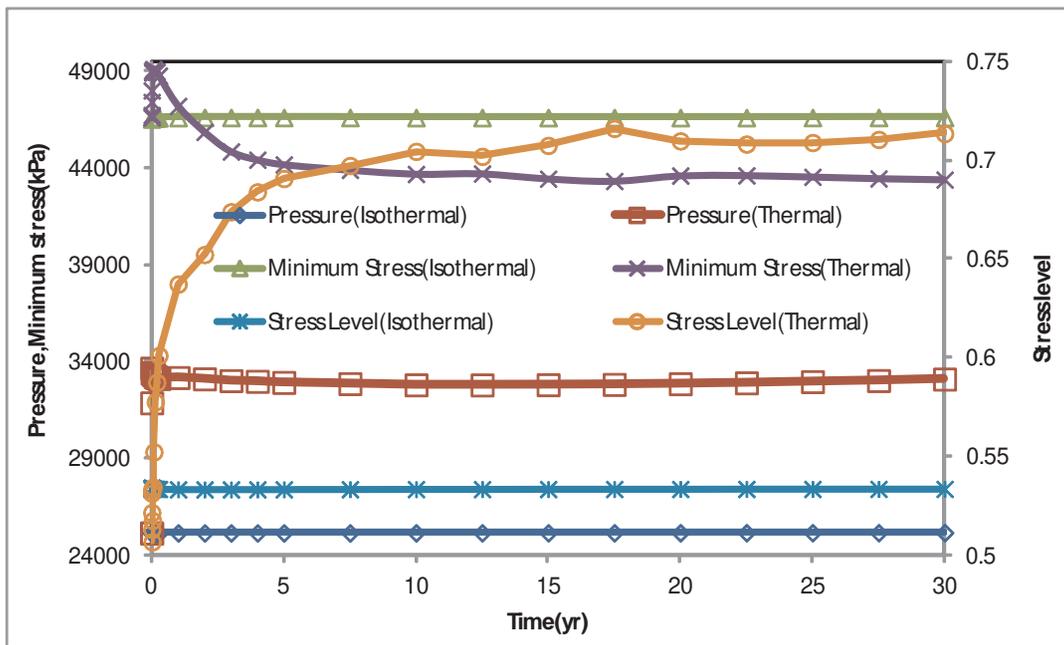
$$l_{\sigma} = \frac{\sigma'_{dev}}{(\sigma'_{dev})_f} = \frac{(\sigma'_{max} - \sigma'_{min})}{(\sigma'_{max} - \sigma'_{min})_f} \leq 1 \quad (1)$$

Where,  $l_{\sigma}$  is the stress level,  $\sigma'_{dev}$  is the deviatoric stress at the current condition,  $(\sigma'_{dev})_f$  is the deviatoric stress at failure,  $\sigma'_{max}$  is the maximum principal stress,  $\sigma'_{min}$  is the minimum principal stress (all stresses are effective). The deviatoric stress at failure is a function of cohesion  $c$  and friction angle  $\phi$  and is defined as:

$$(\sigma'_{dev})_f = \frac{2c \cos \phi + 2\sigma'_3 \sin \phi}{(1 - \sin \phi)} \quad (2)$$

When the stress level is less than 1, the shear stress has not exceeded the shear strength of the rock and when it is larger than 1, the shear strength of the rock has been reached in a plane which is aligned in the direction found from the Mohr stress circle. The nominal rock cohesion for the caprock (Beekmantown Dolomite) is 9000 kPa [17]. Linear elastic constitutive model was used to describe the mechanical behavior of the formation rock. In order to examine the thermal effects on the stress state in the caprock, the variation of total stress, pressure and stress level needs to be studied.

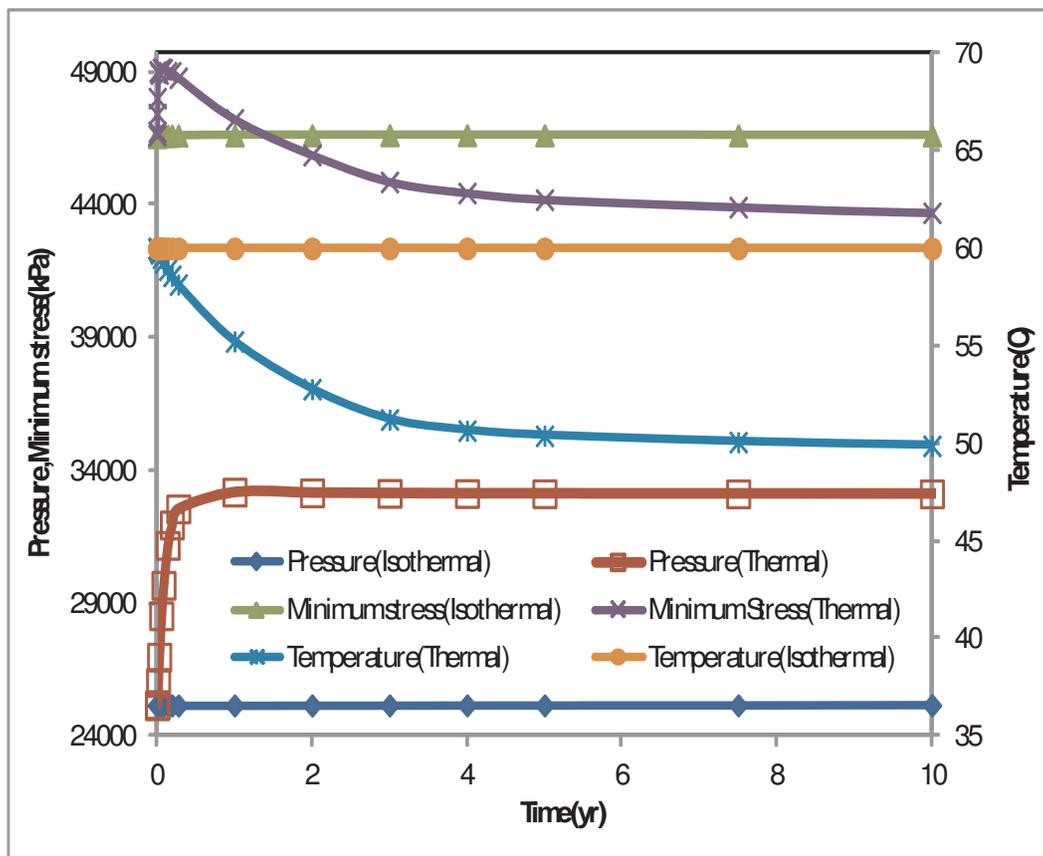
Figure 7 shows the pressure, stress and stress level evolution for the well block in the caprock for the thermal and isothermal model. In the isothermal model, due to the low permeability of caprock, pressure increase in caprock is negligible compared to the reservoir, and stress level remains low. However as seen in Figure 8 (which shows the stress, pressure and temperature variation of the well block in the caprock during the first 10 years of injection), the first caprock layer is quickly pressurized, and later its temperature also decreases due to heat transfer. Stress level is rapidly increasing with time due to thermally induced decrease of total stresses. Therefore the chance of failing the rock in shear for the caprock is higher for the thermal model compared to isothermal model.



**Figure 7.** pressure, minimum total stress, and stress level for the thermal and isothermal model for the well block in the immediate caprock layer

The changes in the stress level correspond to the movement of the Mohr circle with time. Shortly after injection (0.1 days), the stress circle moves to the right due to the slight growth of total stresses. This is a poroelastic effect which is a result of early time-increase of the block pressure in the caprock. This can be clearly seen in Figure 8. However, as soon as the block temperature is lowered due to thermal diffusion (conduction), thermoelasticity dominates and total minimum stress reduces (Figure 8) and stress circle moves to the left toward the failure cone.

The mechanism shown here is somewhat exaggerated because of the upstream numerical treatment of the fracture transmissibility between the blocks, but the relative comparison is valid. Accurate modeling would require very fine vertical grid at the reservoir-caprock interface or the development of more sophisticated numerical technique. These aspects are being currently studied.



**Figure 8.** Minimum total stress, pressure and temperature variation for the well block in the caprock during the first 10 years of CO<sub>2</sub> injection

## 5. Conclusions

This paper studies thermo-elastic and poro-elastic response of the reservoir and caprock to increasing of pressure and reduction of temperature after CO<sub>2</sub> injection and the resulting consequences for the possibility of reaching tensile or shear failure both for the injection below and above reservoir's fracture pressure.

When injecting a fluid below isothermal fracture pressure with a temperature below reservoir temperature, the fracture pressure will decrease and minimum effective stress in the reservoir may reduce below zero for the fracturing to initiate and propagate in the reservoir.

Our results show that the reduction of the minimum effective stress due to thermal effects is larger for the lower reservoir layers. Therefore in case of dynamic fracture propagation, fracture growth would be larger for the lower reservoir layers due to larger cooling for these layers.

Thermal effects of injection with cold CO<sub>2</sub> may also create the possibility of shear failure in the caprock.

## Author details

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