# Long-term effects of fluid injection and production on the thermo-hydro-mechanical behavior of a fractured reservoir

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## 1. Introduction

Deep geological media will be intensively utilized for achieving carbon neutrality within the next few decades (Friedmann et al., 2020). Widespread deployment of geothermal energy production, geologic carbon storage, and subsurface energy storage will require massive injection and production of fluids in porous reservoir rock and fractured low permeable formations. Fluid injection and production causes pore pressure and temperature perturbations that induce deformation and stress changes (Tsang, 1991). These pressure, temperature, and stress changes affect fracture and fault stability, leading to aseismic and/or seismic slip if failure conditions are reached (Cornet et al., 1997).

Understanding how coupled processes control fluid flow and fracture stability is crucial for the success of geo-energy projects. While small shear slip, in the order of mm to cm, can be beneficial to enhance the permeability of the rock mass (Rutqvist and Stephansson, 2003), larger slip, in the order of tens of cm over rupture areas on the scale of hundred meters in diameter, may induce earthquakes that could be felt on the surface, causing nuisance to the local populations and eventually damaging structures and infrastructures (Kanamori and Brodsky, 2004). Numerical simulations of coupled processes are a useful tool to understand the interactions between pore pressure, temperatures, and stress in fractured rock as a result of fluid injection and/or extraction. In this study, we aim at identifying the long-term thermo-hydro-mechanical (THM) response of a fractured reservoir to water injection and production.

## 2. Methods

We perform coupled THM simulations of long-term fluid injection and production into a fractured carbonate rock characterized by two perpendicular sets of fractures. The dip angles of the two fracture sets are 15º and 75º. Fracture permeability is assumed constant and equal to $10^{-13}$ $m^2$, five orders of magnitude higher than the one of the reservoir rock matrix. The reservoir is 120-m thick and is overlaid and underlain by shale of very low permeability, $3\cdot10^{-21}$ $m^2$. We assume a normal faulting stress regime, with a horizontal to vertical effective stress ratio of 0.65. We assume a 2D plane strain model in which the injection and production wells have a flow rate of $5\cdot10^{-3}$ kg/s/m and are separated by 500 m. We maintain injection and production over 30 years. Because injection wells become isenthalpic in the long term, the injected fluid has a lower temperature than the reservoir. In addition to the model that includes the fractures, we also model an equivalent porous medium that yields the same pressure change as the fractured medium model at the injection and production wells. We use the finite element method code CODE_BRIGHT, which solves the THM coupling in a fully coupled way (Olivella et al., 1996).

## 3. Results and Discussion

Simulation results show that the presence of fractures controls not only the pore pressure, but also heat diffusion (in this case – cooling). If an equivalent porous medium is used, the pore pressure evolution at the well can be reproduced (Figure 1). However, the pore pressure within the reservoir significantly differs between the fractured and the equivalent porous medium models. Similarly, the cooling front, resulting from the colder temperature of the injected water with respect to the rock temperature, preferentially advances through the fracture network. The poromechanical stress changes induced as a result of pore pressure and temperature changes, with the highest reduction within the cooled region, depend on the fracture orientation (Zareidarmiyan et al., 2018). As a result, fracture stability is affected differently in the two fracture sets, with the largest instability occurring in the subvertical fractures. In contrast, rock stability equally changes in all directions when considering an equivalent porous medium.

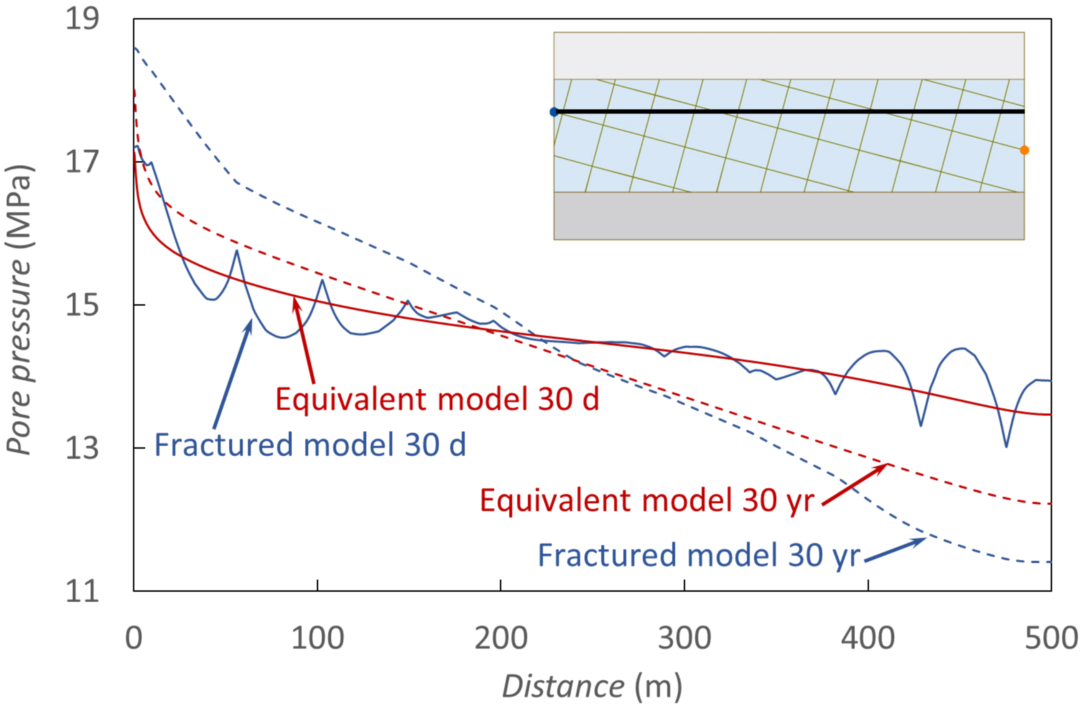


Figure 1. Pore pressure along a horizontal section from the injection well to the boundary where the production well is located, after 30 days and 30 years of water injection and production when considering a fractured medium and an equivalent porous medium.

While the large uncertainty on the existence, geometrical characteristics and properties of fractures makes it complicated to realistically include them in models, oversimplifying representations of the subsurface may result in unreliable predictions of the THM response of fractured rock to fluid injection and/or extraction. Nonetheless, performing coupled THM simulations including a large number of fractures may become quite involved in terms of computational time, especially if visco-elasto-plastic constitute models or velocity-weakening strength models are used. To address some open questions and societal challenges, future research should be oriented towards simulating THM large-scale 3D models with multiple fractures.

## 4. Conclusions

Simulation results display that accurately reproducing the short- and long-term THM response of a fractured rock requires explicitly including fractures in the numerical models. The permeability and stiffness contrast between fractures and the rock matrix controls pore pressure diffusion, heat transport, and poromechanical stress changes. Consequently, the use of equivalent porous medium models may significantly limit the capability of predicting shear slip of fractures, and thus, where permeability enhancement and induced microseismicity may occur.


## Acknowledgements

V.V. acknowledges funding from the European Research Council (ERC) under the European Union's Horizon 2020 Research and Innovation Program through the Starting Grant GEoREST (www.georest.eu) (Grant agreement No. 801809). R.M. is thankful for the support from US DOE through CarbonSAFE Macon County Project DE-FE0029381. F.P. acknowledges funding from the Deutsche Forschungsgemeinschaft (DFG, German Research Foundation) – project number PA 3451/1-1.


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