Deep fracture zone reactivation during CO_2 storage at In Salah (Algeria) – a review of recent modeling studies

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We present a review of numerical studies aimed at understanding the conditions leading to the reactivation of a deep fracture zone, as well as thermal effects, at the In Salah CO_2 Storage Project. Numerical simulations carried out with the TOUGH-FLAC coupled fluid flow and geomechanics simulator show that a deep fracture opening can explain the observed deformation at the ground surface. Accounting for a fractured reservoir with stress-dependent permeability allows for a better match of the recorded wellhead pressure. Simulation results including thermal effects show that cooling becomes more significant for long-term storage, causing a decrease in fracture stability.

Introduction

Despite most modeling studies suggest that a proper pressure management may lead to a safe CO_2 storage, i.e., without inducing earthquakes and without causing CO_2 leakage, demonstration projects are required to turn Geological Carbon Sequestration (GCS) storage into a reality. The In Salah CO_2 Storage Project, Algeria, was an industrial scale GCS demonstration project that permitted to test the geomechanical response of the subsurface to CO_2 injection at relatively high injection pressure (White et al., 2014). About 4 million tons of CO_2 were injected from 2004 to 2011 through three horizontal wells directly into a relatively low-permeable 20 m-thick saline formation, with 900 m-thick caprock preventing the CO_2 to escape (Ringrose et al., 2013). The injected CO_2 reached the storage formation at a temperature around 45 ˚C colder than the rock.

Being the first on-shore demonstration project, In Salah is well known for the wide-ranging monitoring, which included, among other things, pressure monitoring and satellite InSAR data of ground-surface deformation (Mathieson et al., 2010). This latter showed a ground surface uplift of 5-10 mm per year during the injection phase (Fig. 1a). Such uplift was initially associated to the vertical expansion within the reservoir (Vasco et al., 2008; Rutqvist et al., 2010), with a particularly good representation at two of the injection wells (KB-501, KB-503). However, as the injection continued and the InSAR dataset improved, a particular double-lobe uplift was observed nearby the KB-502 injection wells (Fig. 1b). Such a feature has been interpreted as caused by a deep fracture opening, and demonstrated by semi analytical and numerical modeling (Vasco et al., 2010; Rutqvist et al., 2011; Rinaldi and Rutqvist, 2013). The presence of this feature at reservoir depth was also confirmed by seismic characterization (Zhang et al., 2015). Furthermore, recent inverse semi-analytical and numerical studies have further demonstrated that the reactivation of a deep fracture zone could have occurred at all the three wells (Rucci et al., 2013; Rinaldi and Rutqvist, 2017; Rinaldi et al., 2017).

In this paper, we summarize and review the results of numerical modeling aimed at understanding the physical processes leading to the observed ground deformation. The model simulations were conducted using the TOUGH-FLAC simulator (Rutqvist, 2011), linking the multiphase fluid flow TOUGH2 (Pruess et al., 2012) and the geomechanical simulator FLAC3D (Itasca, 2011).

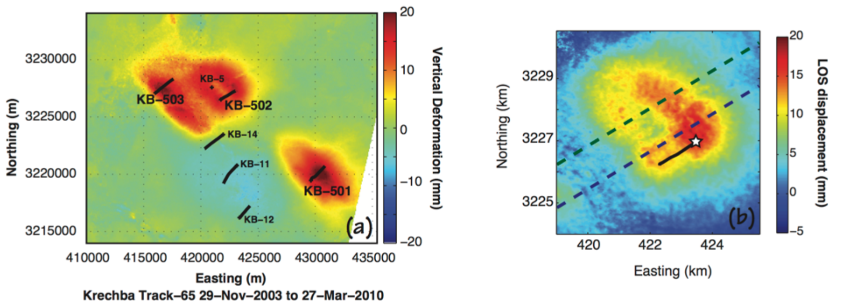

Fig. 1: (a) Observed ground deformation at In Salah in the period 2003-2010. (b) Double-lobe uplift observed at KB-502 injection well. (Figure modified after Rinaldi et al., 2017)

Preliminary modeling at KB-501 and K-B503

Rutqvist et al. (2010) first attempted to reproduce the observed ground deformation at In Salah by using coupled fluid flow and geomechanics simulation. Their analysis showed that most of the observed uplift magnitude could be related to poro-elastic expansion induced by the CO_2 injection in a thin reservoir (20 m). The model setup accounted for a layered model, including a 900 m-thick caprock, with a variable permeability in the range 10^{-21} to 10^{-19} m^2. Results showed that a constant injection rate over a period of 3 years, with an overpressure in the reservoir in the order of 10 MPa (Fig. 2b), could result in a ground surface uplift of 1.2 cm (Fig. 2a).

Rutqvist et al. (2010) also found that some pressure-induced deformations within a 100-m-thick zone of the lower caprock could play a significant role in the observed ground uplift. Indeed, by setting a lower permeability for the caprock region, the deformation is fully explained by the expansion of the reservoir, and satisfactorily reproduces data at KB-501 (Fig. 2c). On the other hand, a high permeability in the caprock allows for a pressurization of the region right above the reservoir, resulting in larger ground uplift as observed at KB-503 injection well (Fig. 2c).

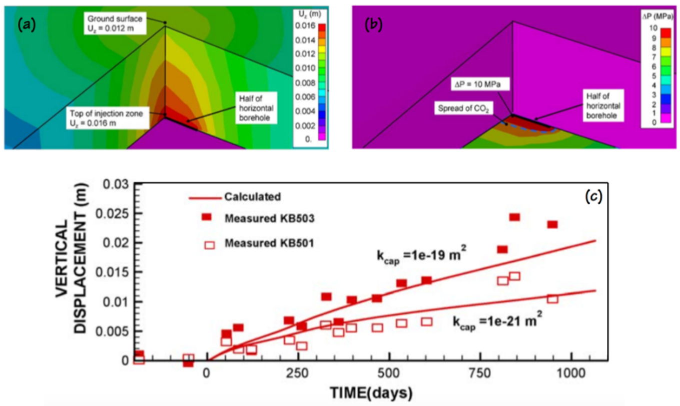

Fig. 2: First coupled geomechanical analysis at In Salah after Rutqvist et al. (2010). (a) Modeled deformation within caprock and at ground surface, and (b) pore pressure changes. (c) Comparison with data at KB501 and KB503 for varying caprock permeability.

Deep fracture zone reactivation at KB-502

Studies by Ringrose et al. (2009) indicated that the pressure distribution at the injection well KB-502 and the occurrence of CO_2 leakage at a monitoring well (KB-5) could have been strongly influenced by pre-existing minor faults and fractures, and, to explain the particular complex observed surface uplift (Fig. 1b), the reactivation of a deep fracture zone in tensile mode was hypothesized (Vasco et al., 2010).

Rutqvist et al. (2011) tried to reproduce a double lobe uplift by using a model grid with a 50 m-wide fracture zone with strongly anisotropic elastic modulus that intersects the injection well and extends about 200 m above the injection zone. Their results showed a maximum uplift of 2 cm after 2 years of injection, with a surface pattern featuring two parallel lobes spaced about 1.5 km (Fig. 3). They also analyzed the simulation results in terms of reservoir stress evolution and the potential for injection-induced micro-seismicity at Krechba. Results highlighted that the combined effect of increased pressure and cooling could rise the potential for induced micro-seismicity, especially close to the cooled injection well, but given the strike-slip stress regime at Krechba such potential was still estimated to be relatively low.

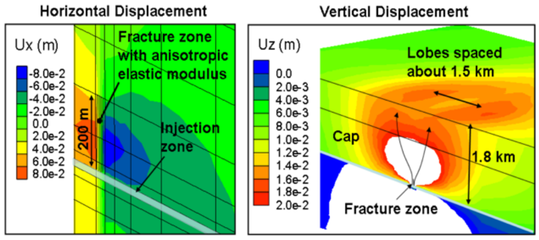

Fig. 3: Preliminary forward coupled numerical modeling of CO_2 injection with pressure inflation of the vertical fracture zone (Figure from Rutqvist et al., 2011)

The preliminary results by Rutqvist et al. (2011) were qualitatively in agreement with the observation at KB-502, and motivated a more comprehensive modeling of the deep fracture zone reactivation presented by Rinaldi and Rutqvist (2013). In their study, they simulated a fracture zone with high permeability and low mechanical stiffness. In order to correctly reproduce the transient evolution of displacement and pressure, the fracture zone was simulated as reactivating after a few months of injection, causing irreversible changes in permeability. The computational model closely followed previous formulations (Fig. 4a), and the fracture zone was simulated as a highly permeable zone, 80 m wide and cross cutting the 1 km–long horizontal injection well (Fig. 4b). The 3500 m length and 350 m extent of the fracture zone within the caprock were determined by model calibration. In order to match the bottomhole pressure (Fig. 4c), the model included a time-step function permeability, in agreement with a stress-dependent formulation (Liu and Rutqvist, 2013). This formulation allowed for a detailed representation of both transient evolution of the displacement and pattern of deformation. Figure 5 shows that the resulting displacement calculated in the satellite's Line Of Sight is in good agreement with the measured uplift. The shape of deformation is similar, with two asymmetric lobes (Fig. 5a and 5b), and a more detailed comparison along two arbitrary profiles shows

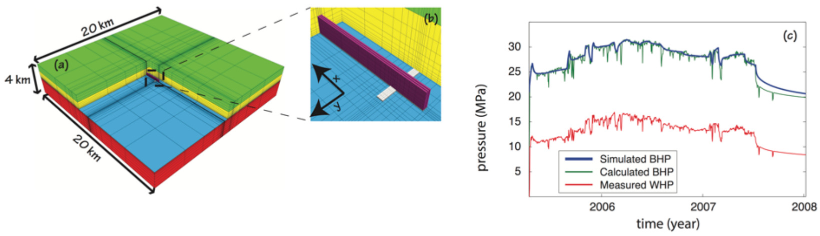

Fig. 4: Detailed modeling of deep fracture zone modeling at KB-502 (figure after Rinaldi & Rutqvist, 2013). (a) Computational mesh. (b) Simulated and measured pressures.

a very good match between data and simulation, particularly in the double lobe region and with only minor differences in the far field (Fig. 5c and 5d, red line for the simulation results and green dashed line for the InSAR data). The transient evolution of the uplift was also compared to InSAR data above the injection well (Fig. 5e), with a good agreement between data and simulation during the uplift phase, while differences arise after shut in.

Overall the analysis by Rinaldi and Rutqvist (2013) supported the notion of a fracture zone confined within the caprock. A sensitivity analysis confirmed that only a fracture zone confined within the caprock could allow matching of all available field information, including time evolution of pressure and deformation, and the 3D seismic indication of a CO_2 saturated fracture zone extending for some thousand meters laterally.

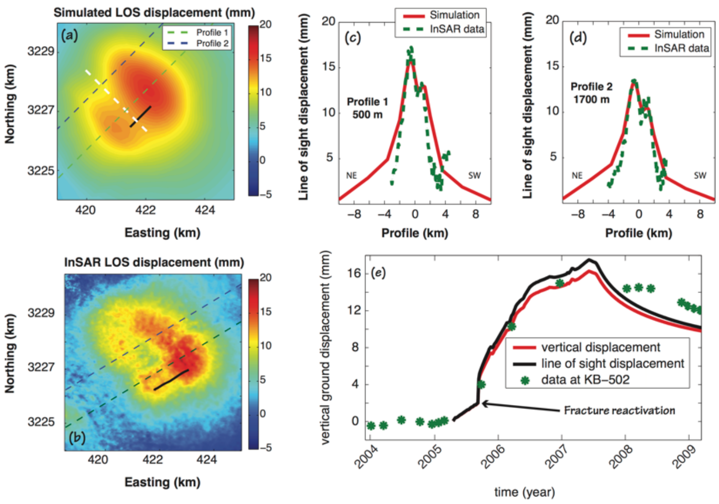

Fig. 5: (a, b) Modeled and InSAR LOS at KB-502 after about 2 years of injection. (c, d) Comparison between data and simulation at two arbitrary profiles located at 500 m and 1700 m from the injection well. (e) Transient evolution of ground surface uplift and comparison with InSAR data. (figures after Rinaldi & Rutqvist, 2013)

Inverse modeling approach and permeability variation

A recent work by Rinaldi et al. (2017) further improved the formulation of the coupled analysis of pressure and ground deformation by employing an inverse modeling approach with iTOUGH2-PEST and TOUGH-FLAC. The forward model was improved by accounting for a Mohr-Coulomb criterion to determine the time of reactivation of the fracture zone and onset of permeability changes, which followed a more rigorous stress-dependent formulation (Liu and Rutqvist, 2013; Rinaldi et al., 2014).

Such an improved formulation allowed to extend the study of deep fracture zone reactivation also at KB-501 and KB-503, as already hypothesized by semi-analytical models (Rucci et al., 2013). On the one hand, the results confirmed the previous formulation for KB-502, by using a more rigorous approach (Fig. 6c and 6d). On the other hand, results also showed that the opening of a deep fracture zone could explain the observed transient evolution of pressure and displacement at KB-501 (Fig. 6a and 6b) and KB-503 (Fig. 6e and 6f), although a similar good fit could be achieved for the case of an intact caprock without fracture zone opening.

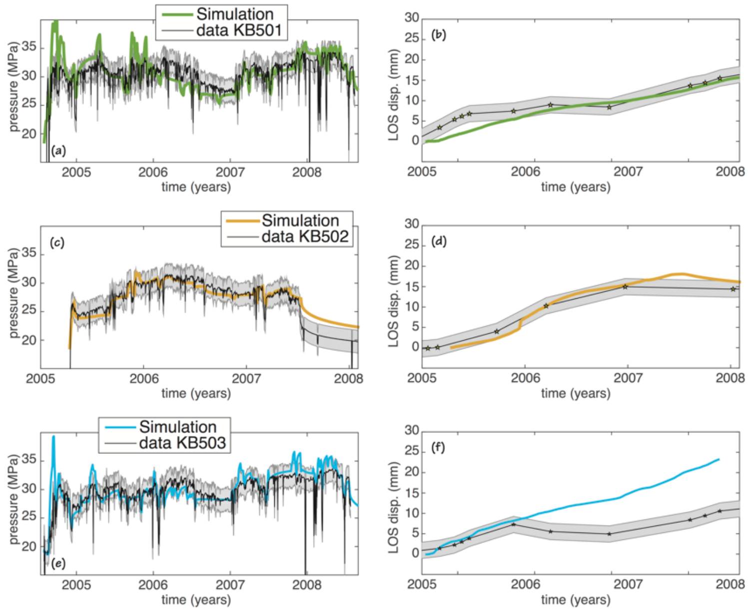

Fig. 6: Inverse modeling of coupled fluid flow and geomechanics with deep fracture zone reactivation at (a, b) KB-501, (c, d) KB-502, and (e, f) KB-503. Figures modified after Rinaldi et al. (2017) and Rinaldi & Rutqvist (2017).

Thermal effects

Recently, Vilarrasa et al. (2017), evaluated the thermal effects on fracture reactivation at the KB-502 injection well. By using a 2D model, and by employing the inverse modeling formulation (Rinaldi et al., 2017), they were able to reproduce the evolution of the CO_2 plume, including indication of early CO_2 arrival at the location of the leaky well KB-5. The proposed model showed that the temperature changes may have extended within the fracture zone, but their effect in terms of injectivity changes was probably much smaller if compared to the changes induced by pressure. However, they also demonstrated that in a hypothetical scenario with low pressure (e.g., larger reservoir permeability), thermal stress may increase the permeability in fracture zones resulting in pressure drop (Fig. 7a). As also highlighted by Rutqvist et al. (2011) and Vilarrasa et al. (2015), the thermal stress changes (Fig. 7b) may cause a decrease in fracture stability in the long term, which may induce microseismicity. Cooling, which advances much behind the CO_2 plume, causes contraction of the rock matrix, opening up existing fractures, and thus, leading to an increase in injectivity.

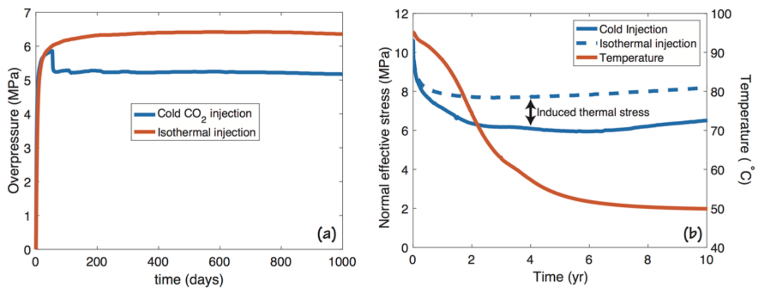

Fig. 7: Long term effect of thermal changes in a scenario similar to In Salah with low pressure injection. (a) Pressure changes highlight changes in injectivity. (b) Induced thermal stress changes that may result in microseismicity. (figures after Vilarrasa et al., 2017)

Conclusion

In this paper, we presented recent numerical modeling results obtained with the simulator TOUGH-FLAC to study the coupled CO_2 injection and ground surface uplift at the In Salah storage site. Results were presented from the preliminary works, which attributed most of the deformation to inflation of the injection reservoir, up to very recent results, demonstrating the role of fracture zone reactivation in the framework of CO_2 sequestration as well as thermal effect decreasing fracture stability in the long term. The present review highlights the importance of complex coupled fluid flow and geomechanical modeling to properly assess the physical processes occurring at depth during underground exploitation.

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