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Coupled reservoir-geomechanical analysis of CO_2 injection at In Salah, Algeria

Jonny Rutqvist[a,]*, Donald W Vasco[a], Larry Myer[a]

[a]*Earth Sciences Division, Lawrence Berkeleley National Laboratory, MS 90-1116, Berkeley, CA94720, USA*

Abstract

In Salah Gas Project in Algeria has been injecting nearly one million tonnes CO_2 per year over the past four years into a water-filled strata at a depth of about 1,800 to 1,900 m. Unlike most CO_2 storage sites, the permeability of the storage formation is relatively low and comparatively thin with a thickness of about 20 m. To ensure adequate CO2 flow-rates across the low-permeability sand-face, the In Salah Gas Project decided to use long-reach (about 1 to 1.5 km) horizontal injection wells. In this study we are using field data and coupled reservoir-geomechanical numerical modeling of CO_2 injection to analyze geomechanical responses and to assess the effectiveness of this approach for CO_2 storage in relatively low permeability formations. Among the field data used are surface deformations evaluated from recently acquired satellite-based inferrometry (In SAR). The In SAR data shows a surface uplift on the order of 5 mm per year above active CO_2 injection wells and the uplift pattern extends several km from the injection wells. We use the observed surface uplift to constrain our coupled reservoir-geomechanical model. We conduct sensitivity studies to investigate potential causes and mechanisms of the observed uplift. Preliminary results of our analysis presented in this paper indicates that most of the observed uplift magnitude can be explained by poro-elastic expansion of the 20 m thick injection zone, but there could also be a significant contribution from pressure changes within the adjacent caprock. Moreover, we show that surface deformations from In SAR can be useful for tracking the fluid pressure and for detection of a permeable leakage path (e.g. in a permeable fault) through the overlying caprock layers.

Keywords: Type your keywords here, separated by semicolons ;

1. Introduction

The In Salah Gas project (a joint venture between Sonatrach, British Petroleum, and StatoilHydro) located in the central region of Algeria, is the world's first industrial scale CO2 storage project in the water-leg of a depleting gas field. Natural gas produced from the area is high in CO_2 and the CO_2 is being returned to the earth for geological

* Corresponding author. Tel.: +1-510-486-5432 ; fax: +1-510-486-5686 .
E-mail address: jrutqvist@lbl.gov .

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storage. Nearly one million tonnes CO_2 per year has been injected since August 2004 into relatively low-permeability, 20 m thick, water-filled carboniferous sandstone at a depth of about 1,800 to 1,900 m, around the Krechba gas field (Wright, 2006). To ensure adequate CO2 flow-rates across the low-permeability sand-face, the In Salah Gas Joint Venture (JV) decided to use long-reach (about 1 to 1.5 km) horizontal injection wells.

The storage formation is an excellent analogue for large parts of North-West Europe and the US Mid-West, where large CO_2-storage will be required if CO_2 Capture and geological storage (CCS) is to make a significant contribution to addressing CO_2 emissions (Wright 2006). The In Salah Joint Industry Project (JIP) has been launched for research and development and CCS demonstration at In Salah with widespread participation from research and development organizations in both academia and private industry. The storage location is instrumented and data is being collected and analyzed, to monitor location and behavior of the CO_2.

Because of a relatively deep reservoir, a relatively stiff overburden, and the volume of CO_2 being injected is fairly small compared to the overburden, the initial view of the In Salah JIP was that no significant ground deformations would occur. However, in the fall of 2006 a preliminary reservoir-geomechanical analysis conducted at the Lawrence Berkeley National Laboratory (LBNL) using the TOUGH-FLAC numerical simulator (Rutqvist et al., 2002) indicated that surface deformations on the orders of centimeters would be feasible. As a result, it was decided to explore the possibility of using the satellite-based inferrometry (In SAR) for detecting groundsurface deformations related to the CO_2 injection. In SAR data were acquired and analyzed by Tele-Rilevamento (TRE), using a state-of-the-art permanent scatterer method (PS) enabling determination of millimeter-scale surface deformations. The results presented in Vasco et al. (2008a, b) were remarkable, because the observed uplift could be clearly correlated with each injection well (with uplift bulges of several km in diameter centered around each injection well). Measured uplift occurred within a month after start of the injection and the rate of uplift was approximately 5 mm per year amounting to about 1.5 cm in the first 3 years of injection. One reason for the success of the InSAR technology at Krechba is the fact that the ground surface consists of relative hard desert sediments and bare rock.

The uplift data and its correlation with underground reservoir structures are currently under investigation by several research groups within the In Salah JIP using various strain inversion techniques and coupled modeling approaches. In this paper we present a coupled reservoir-geomechanical modeling of the CO_2 injection at Krechba. In this approach we simulate the actual CO_2 injection in a three-dimensional model around one horizontal injection well, and conduct sensitivity studies to determine the cause and mechanisms of the uplift. In this first preliminary study, we are not attempting to make an exact inversion of the uplift pattern around the three injection well, but rather we focus on a simplified geological representation, yet involving all the key geological features (including reservoir, caprock, overburden, underburden, and possible fault structure), and processes (multi-phase CO_2-brine flow interactions and coupled geomechanical changes).

2. Krechba site and observed surface deformations

The Krechba field is defined by the structural high of a northwest-trending anticline. Gas produced from this field and two nearby fields contains CO_2 concentrations ranging from 1% to 9%, which is above the export gas specification of 0.3%. The CO_2 from the three fields is separated from the hydrocarbons and reinjected into three adjacent wells “KB-501, KB-502, and KB-503” at the rate of tens of millions of cubic feet per day. The injection is restricted to a 20-m-thick layer, at about 1,800 to 1,900 m depth (Wright, 2006). The reservoir is overlain by more than 900 m of low permeability mudstones, which forms a significant barrier to flow. LBNL and TRE, in partnership with British Petroleum, examined the utility of satellite range change data for monitoring the reservoir during CO_2 injection. Of particular interest was the identification of features controlling flow and the possibility of detecting CO_2 migration out of the reservoir and into the lower parts of the caprock. Because the reservoir initially is water filled, the injection of CO_2 into the water column induces multiphase flow. The CO_2 behaves supercritically at reservoir pressures, with a viscosity and density only moderately different from water (Vasco, 2008a).

Figure 1a presents the average rate of range change per year, which is close to the average vertical surface displacements per year. The CO_2 injection commence in August 2004 at KB501 and KB503, and April 2005 at KB502. During injection, the bottom hole pressure is limited to below the fracturing gradient leading to a maximum pressure increase of about 10 MPa above the ambient initial formation pressure. Figure 1a shows the average vertical uplift of about 5 mm per year above each of the three injection wells. In the Krechba gas field, located between the three injection wells, a small settlement is believed to be a result of production-induced pressure depletion.

Figure 1b shows the time evolution of vertical displacement for one PS point located above KB501, indicating a gradual uplift from August 2004, when CO_2 injection commenced. The KB501 injection data shows continuous CO_2 injection at a more or less constant well head pressure from the start of the injection and the injection rate averaged at about 15 MMscfd (million standard cubic feet per day). The gradual vertical uplift with time observed in Figure 1b indicates that the uplift does not react instantaneously to injection pressure, but rather appears to be correlated with the injected volume.

3. Model setup

The simulation problem was discretized into a 3-dimensional mesh, 10 by 10 km wide and 4 km deep around one horizontal injection well, which was located at a depth of about 1810 m below ground level within the 20 m thick injection formation, the so-called C10.2 sandstone. The model consists of four main geological layers as published in the literature (IPPC 2005): (1) Cretaceous sandstone and mudstone overburden (0-900 m), (2) Carboniferous mudstones (900-1800 m), C10.2 sandstone (1800-1820 m), and (4) D70 mudstone underburden (below 1820 m). An additional simulation case was conducted in which a hypothetical vertical fault or zone of increased permeability across the caprock was introduced. There are no indications that such through going fault zone exists at Krechba, but such the fault was introduced into the numerical model to investigate the signature of surface deformations if such fault zone would exist, and if fluid would migrate upward along such a fault structure.

Initial estimates of the elastic properties of the injection formation were derived from laboratory experiments by the University of Liverpool, U.K, whereas the properties of other geological layers were estimated using sonic logs. For the injection zone, a Young's modulus E = 6 GPa and a Poisson's ratio ν = 0.2 were adopted from a few laboratory experiments on C10.2 samples that had a porosity ranging from 15 to 20 %, consistent with estimates of in situ porosity. From the sonic logs we estimated that the caprock (Carboniferous mudstone and tight sandstone) is somewhat stiffer and that the shallow overburden (Cretaceous sandstones and mudstones) is somewhat softer.

A permeability of the injection zone was estimated to 1.3×10^{-14} m^2 (13 mDarcy) by model calibration to achieve a reasonable pressure increase of about 10 MPa for an adopted injection rate of 15 MMscfd. This is within the range of observed permeability range (Iding and Ringrose, 2008). The caprock permeability was varied from 1×10^{-21} to 1×10^{-19} m^2, a reasonable range for shale and mudstone seals (Zhou et al. 2008) and also within the range of recent results from laboratory experiments conducted by the University of Liverpool. The porosity was set to 17% based on in situ estimates from borehole logging and seismic surveys.

An initial temperature, pressure and stress gradients were derived from site investigations at Krechba. With the adopted gradients, the initial temperature and pressure at the depths of the modeled injection zone is about 90 °C and 17.9 MPa, respectively..

The lateral boundaries are set to a constant fluid pressure, temperature and stress, whereas the bottom (at 4 km depth) is a no flow boundary with vertical displacement fixed to zero.

The modeling was conducted for a constant injection rate of 15 MMscfd corresponding to an average rate in the field for well KB501 over a time period of 3 years, approximately representing the average injection rate at KB501.

4. Simulation results

Figure 2 shows the simulation results of vertical displacement for a base case without a permeable vertical fault. In general, the simulation results show that the uplift increases gradually with time during the simulated 3-year CO_2 injection. Figure 2b indicates a significant impact of caprock permeability on the magnitude of surface uplift. When caprock permeability is set to 1×10^{-21} m^2, the uplift is determined by the volumetric expansion of the injection zone as a result injection induced pressure changes and associated reduction in vertical effective stress. Increased fluid pressure within the injection zone results in a vertical displacement of about 1.5 cm at the top of the injection zone and an attenuated uplift of about 1.2 cm of the ground surface (Figure 2a). When increasing the caprock permeability from 1×10^{-21} m^2 to 1×10^{-19} m^2, the maximum uplift of the ground surface increases from 1.2 to 2.0 cm (Figure 2b). When the caprock permeability is 1×10^{-19} m^2 a slight amount of fluid migrates into the caprock and causes an increase in fluid pressure within the caprock, just above the injection zone. This increased caprock fluid pressure causes additional volumetric expansion that significantly contributes to the magnitude of ground uplift. For a permeability of 1×10^{-19} m^2 this pressure increase occurs only in the very lowest part of the caprock, i.e. limited to within about 50 m above the injection zone. It is caused by a small amount of water permeating into the caprock.

Figure 3 shows simulation results of surface uplift without and with a permeable fault. In the case a permeable fault penetrating the caprock, distinct ground uplift occurs directly above the fault. The magnitude of this uplift is about 5 times that of the case without a fault. The simulation results shows that fluid pressure migrate up along the fault and then into the adjacent matrix rock which then causes the additional uplift. Moreover, at the end of the 3-year injection period, the distinct uplift has occurred without any CO_2 migration up along the fault. This shows that monitoring of surface deformations can be used to detect permeable leakages paths before any CO_2 leakage occur. To date no major fault is known to intersect the caprock at Krechba, and the observed surface deformation does not indicate fluid migrations towards to upper parts of the caprock.

5. Concluding remarks

This paper present the progress in coupled reservoir-geomechancial modeling of CO_2 injection at In Salah, Algeria. We used surface deformations evaluated from recently acquired satellite-based inferrometry (In SAR) to constrain our model. The In SAR data shows a surface uplift on the order of 5 mm per year above active CO_2 injection wells and the uplift pattern extends several km from the injection wells. Preliminary results of our coupled reservoir-geomechanical analysis show that the observed uplift is consistent with volumetric expansion of the injection zone and/or adjacent formations as a result of injection induced pressure changes. The uplift depends on the magnitude of pressure change, injection volume, and elastic properties of the reservoir and overburden. Pressure changes in the lower parts of the caprock formation may significantly contribute to the observed uplift. Finally, we show that if the injection zone is intersected by a permeable fault, and if injection induced fluid pressure would migrate upward through the caprock, a distinct uplift of the groundsurface would occur directly above the fault. Such an uplift signature would occur as a result of pressurization of the native water within the fault before any CO_2 migrates out of the injection zone. Thus, monitoring the surface deformations from In SAR can be useful for tracking the fluid pressure and for detection of a permeable leakage path through the overlying caprock layers.

Acknowledgments

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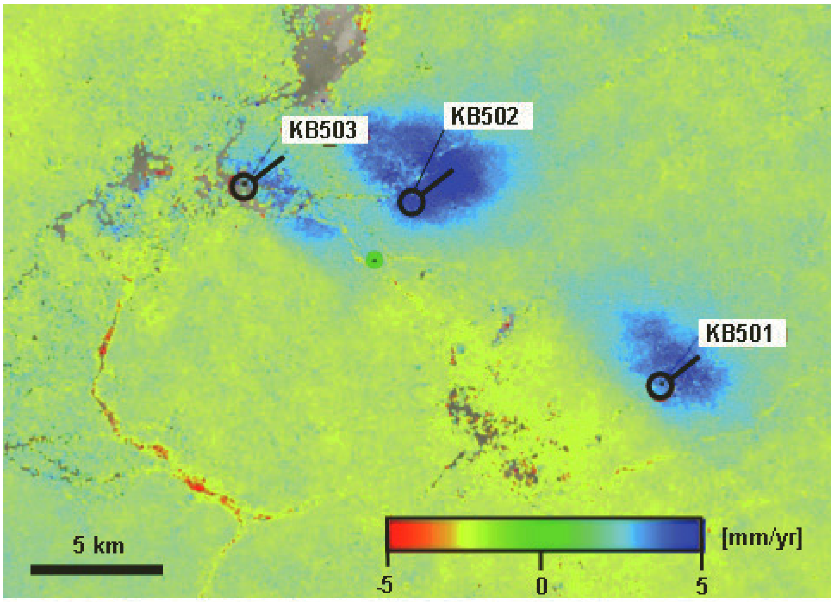
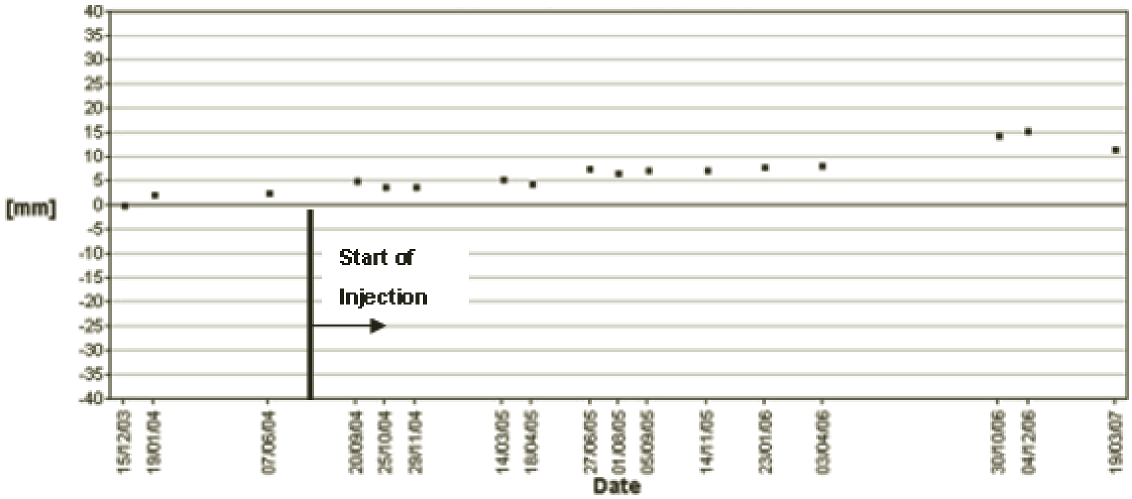
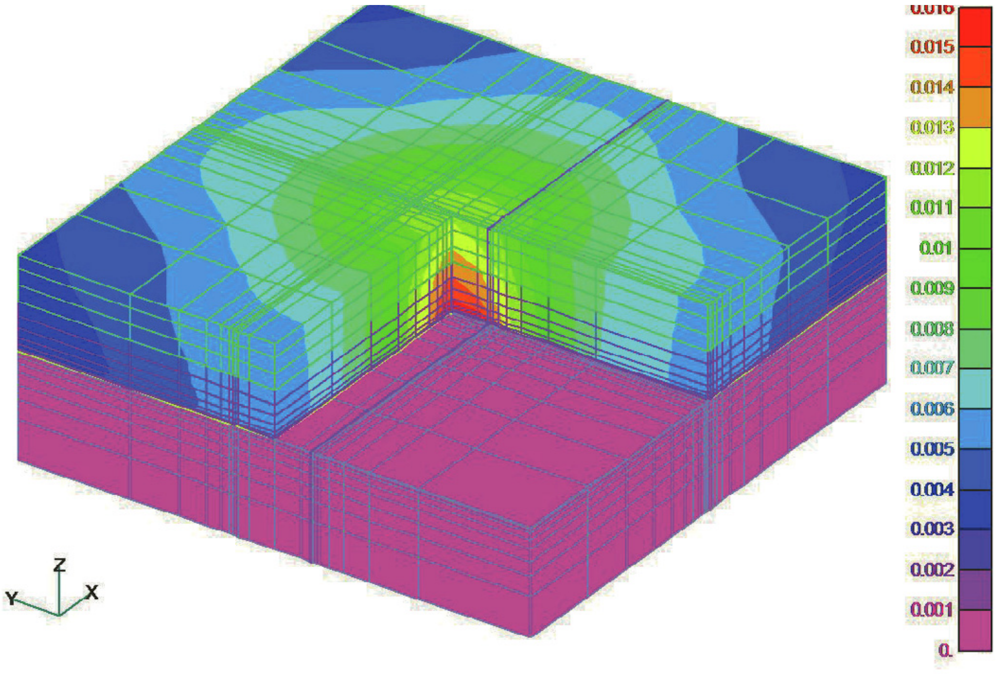


(a)

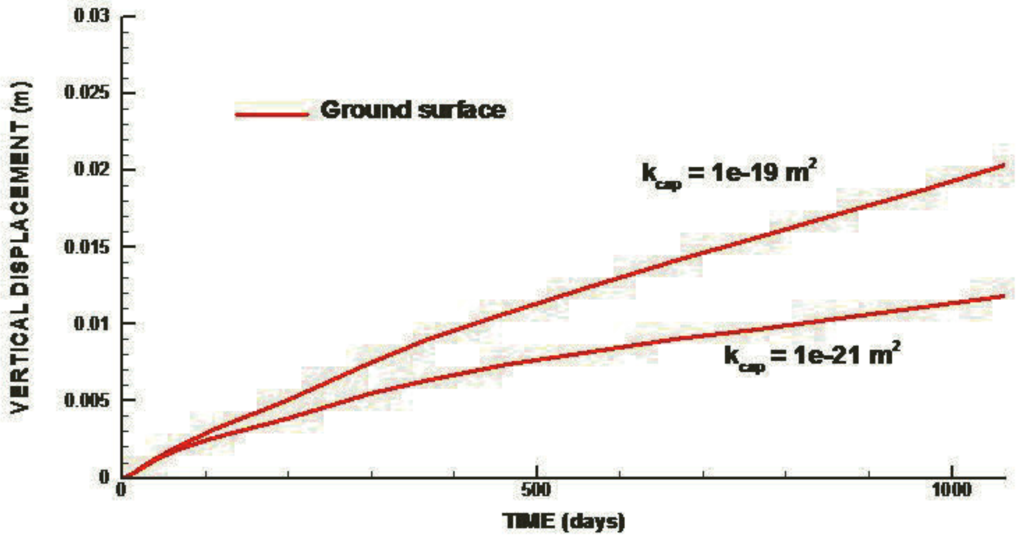


(b)

Figure 1. In SAR data of range change evaluated by TRE: (a) Rate of vertical displacements at 3 years, and (b) time evolution of vertical displacement for one PS point located above KB501.



(a)



(b)

Figure 2. Simulated vertical displacement during 3 years of CO_2 injection: (a) Vertical displacement (in meter) after 3 years of injection with an impermeable caprock (k=1e-21 m^2), and (b) evolution of vertical displacement for two cases of caprock permeability.

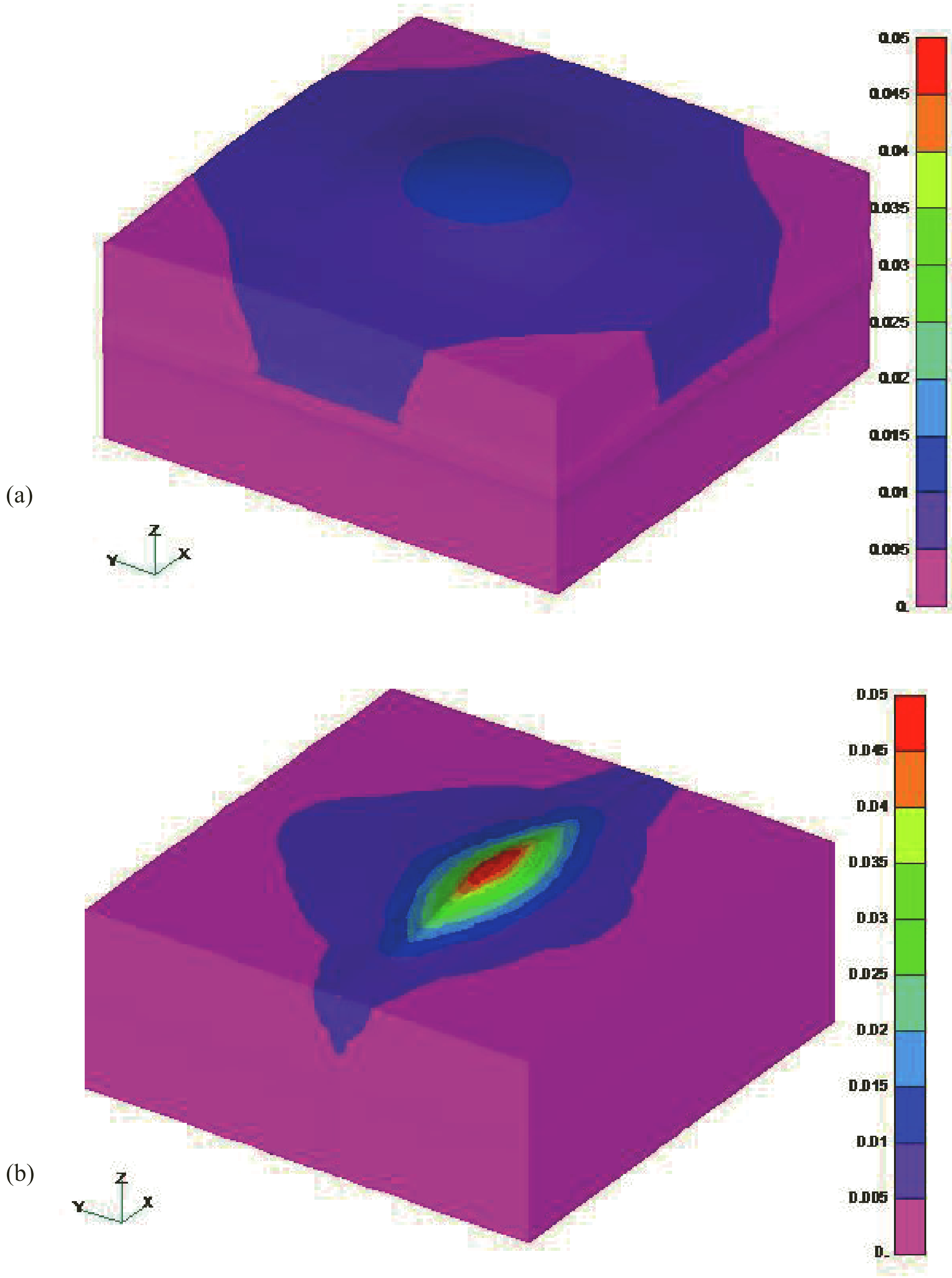


Figure 3. Simulated vertical displacement (in meter) after 3 years of CO_2 injection (a) without and (b) with a permeable fault intersecting the caprock. Figure b shows distinct additional uplift as a result of upward fluid pressure migration along the permeable fault.