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Investigation of the influence of geomechanical and hydrogeological properties on surface uplift at In Salah

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ABSTRACT

Coupled reservoir and geomechanical simulations are significantly important to understand the long-term behavior of geologic carbon storage (GCS) systems. In this study, we performed coupled fluid flow and geomechanical modeling of CO_2 storage using available field data to (1) validate our existing numerical model and (2) perform parameter estimation via inverse modeling to identify the impact of key geomechanical (Young's modulus and Biot's coefficient) and hydrogeological (permeability and anisotropy ratio) properties on surface uplift and the pore pressure buildup at In Salah in Algeria. Two sets of surface uplift data featuring low and high uplifts above two injection wells and the maximum change in the pore pressure due to CO_2 injection were used to constrain the inverse model. Forward simulation results with representative parameter values from the literature match both low and high surface uplifts reasonably well and predicted the maximum change in the pore pressure. In particular, forward modeling results with estimated Biot's coefficients for reservoir and caprock layers, match the observed uplift well, highlighting the significance of Biot's coefficient in coupled reservoir and geomechanical models. Parameter estimation with 12 parameter sets for both low and high uplift data demonstrates that multiple sets of parameters can match the observed data equally well and the inclusion of the pore pressure data is critically important to constrain the parameter solution during inverse modeling. For a majority of cases, estimation results for both low and high uplift data show the vertical intrinsic permeability and Young's modulus of the reservoir remained close to 13 mD (1.3×10^{-14} m^2) and 10 GPa, respectively, suggesting that these parameters may represent the actual effective properties. Additionally, higher correlations between reservoir permeability and caprock's Biot's coefficient with high surface uplift data were observed consistently under the pore pressure constraint, suggesting the inclusion of the pore pressure constraint is required to estimate the proper values of coupled flow and geomechanical properties associated with different surface uplift data. Overall, this study suggests that given limited data, including Biot's coefficient, in addition to permeability and Young's modulus can enhance parameter estimation of the geomechanical response during GCS.

1. Introduction

Over the last decade, geologic carbon storage (GCS) has been proposed as a promising technology to reduce CO_2 emission to the atmosphere. It is critical to understand geomechanical processes and impacts from CO_2 injection to ensure that CO_2 can be securely stored over geological time. Coupled multiphase flow and geomechanical models can be used to understand and assess effects of increased reservoir pressure by CO_2 injection on the geomechanical response. One of the prominent field demonstration projects is the In Salah Gas project, located in Algeria, where CO_2 recovered in natural gas production was reinjected into a sandstone reservoir formation (Eiken et al., 2011). The spatial distribution of surface uplift was successfully evaluated using data obtained from the satellite based inferometry (InSAR) (Vasco and Novali, 2008; Vasco et al., 2008). This uplift data and other geophysical data have been used to investigate reservoir properties and coupled flow and mechanical processes (Rutqvist et al., 2009, 2010; Preisig and Prevost, 2011; Shi et al., 2013).

In the past, predictions of the impact of CO_2 injection on the geomechanical response, such as surface uplift, have been performed with relatively simple models. The use of simple models has been

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justified because of nonlinearities of coupled multiphase flow and geomechanical response, the associated computational expense, and/or a lack of field data. Rutqvist et al. (2009, 2010) investigated the relationship between the surface uplift and pore pressure change as well as deformation within the injection zone at In Salah, using coupled reservoir and geomechanical modeling. They showed consistency between the simulation results and the measured data from InSAR on the surface uplift. They demonstrated that volumetric expansion of reservoir rocks and surrounding shaly sands may contribute to the surface uplift. This volumetric expansion depends on both permeability and elastic properties of the reservoir and overlying caprock. Preisig and Prevost (2011) presented a two-dimensional (2D) fully coupled multiphase thermo-poromechanical model for simulating CO_2 injection at In Salah. Their 2D-model over-predicted the surface uplift. They concluded the lack of the accurate field data to be the reason. They also demonstrated that creation or reopening of fractures can be attributed to temperature differences between injected fluid and reservoir rock. Reservoir characterization of faults and fractures has been performed to enhance the understanding of CO_2 flow in fractured rocks at In Salah (Iding and Ringrose, 2010; Pamukcu et al., 2011; Deflandre et al., 2011). Iding and Ringrose (2009, 2010) confirmed the presence of fractures and small faults in both the reservoir and the lower caprock, based on the long-term performance data of In Salah field. They concluded that despite the clear evidence of fractures in the reservoir, a thick caprock layer provides an effective hydrological and mechanical barrier to CO_2 leakage. Recently, Smith et al. (2011, 2013) also investigated possible fracturing within the reservoir and lower caprock near one of the CO_2 injection wells at In Salah. They concluded that at the given injection rates, induced fracturing into the upper caprock should not occur and the possibility of CO_2 leakage through induced fractures is low. Geophysical inverse techniques using InSAR and seismic data have been employed to estimate reservoir volume change and fault-fracture aperture change after CO_2 injection (Vasco et al., 2010). The results indicate that CO_2 associated flow can extend up to several kilometers through the fracture/fault zone in the reservoir formation at In Salah. However, all of these models did not fully employ coupled multiphase flow and geomechanical modeling.

Accurate identification of geomaterial properties is essential for predicting fluid flow and geomechanical response. In reservoir engineering literature, the process of calibrating model parameters with dynamical data is known as “history matching”. Using a multiphase flow simulation, Pamukcu et al. (2011) manually performed history matching at the In Salah site to calibrate the porosity and permeability of matrix and fracture network in the reservoir using bottom hole pressures, CO_2 injection rates, and a CO_2 breakthrough time at a monitoring well. Although they matched observed data reasonably well, they concluded that coupled multiphase flow and geomechanical modeling is required to confirm their simulation results. Recently, Shi et al. (2012) performed history matching with the temporal changes in the maximum vertical uplift to estimate Young's modulus. The reservoir model with stochastically generated porosity and permeability static fields was first calibrated with observed dynamic bottom hole pressures to estimate fracture transimissibility of reservoir and lower caprock layers independently. The calibrated reservoir model was then imported into a coupled reservoir-geomechanical model in order to calibrate Young's modulus of the lower caprock with surface uplift data near one of three injection wells. The calibrated model was then used to match InSAR surface uplift observed at two other injection wells, demonstrating that model predictions capture the overall trend well, but the mismatch was much greater. Despite their history matching with manual tuning of 1–2 parameters, the physical models were built upon the best estimation of reservoir and geomechanical characterization. Their results clearly highlighted the importance of coupled reservoir-geomechancal modeling to evaluate the performance of CO_2 injection at the reservoir scale. Zhou and Burbey (2014) mentioned despite the fact of limited hydrogeological and geomechanical information about the host rock formations, development of these sophisticated surface monitoring techniques such as InSAR and GPS, can yield critical information about the rock formations, which can be used in numerical modeling to monitor the fate and transport of the injected fluid.

In a more general aspect of reservoir simulation, Nanayakkara and Wong (2009) provide an interesting discussion on analytical and numerical modeling of surface uplift due to subsurface injection. They investigated multiple cases and showed the importance of the boundary, in terms of both the location of the boundary and the boundary conditions. Their study revealed that more realistic results could be obtained through fixed displacement boundary conditions at the bottom boundary as well as selecting sufficient lateral extent. Khakim et al. (2012) also tested a two-step inversion method to estimate the distribution of reservoir deformation and volume change due to steam injection using a 3D synthetic problem. The depth of injection point was first estimated with approximate modeling of the deformation, followed by the accurate estimation of the reservoir deformation and volume change due to the surface uplift with the InSAR-derived surface deformations. However, it was not tested in a multiple layered system whose mechanical and hydrogeological properties can vary significantly. Aoyagia et al. (2013) have developed a numerical simulator for environmental impact assessment. The In Salah CO_2 storage case was used to validate the simulation. They also performed a sensitivity analysis on some parameters, such as caprock permeability, porosity and Young's modulus of the reservoir. They found that caprock permeability can significantly affect the surface uplift.

Over the past decade, optimization, sensitivity, and uncertainty quantification of multiphase flow models during GCS have been developed in the literature (Espinet and Shoemaker, 2013; Wainwright et al., 2013; Tavakoli et al., 2013). However, automatic parameter estimation of coupled multiphase flow and geomechanical models has not been thoroughly investigated. A study of geomechanical deformation due to CO_2 injection by Verdon et al. (2013) highlights the importance of systematic geomechanical evaluation prior to CO_2 injection. Because of the non-uniqueness of the inverse problem and model uncertainty, multiple parameter sets with various starting points need to be compared. This allows evaluating the sensitivity of correlated parameters when calibrating the model (McKenna and Pike, 2013; Yoon et al., 2013).

The aim of this study is to identify and rank the importance of key geomechanical and hydrogeological parameters using coupled flow and geomechanical simulations to have a better understanding of the surface uplift at In Salah, Algeria. Because of the lack of field data, there is a high uncertainty involved in the model parameters. This uncertainty arises from geomechanical, hydrogeological properties and the coupling parameters. In this study, the sensitivity of the surface uplift to some of these critical parameters will be investigated. Specifically, two sets of surface uplift data featuring low and high uplift above two CO_2 injection wells are used. In addition, the maximum change of pore pressure due to CO_2 injection is included to evaluate the impact of pore pressure constraint on surface uplift during parameter estimation. After validating our coupled forward model with the representative parameter values in the literature, simulation results are used to evaluate the significance of permeability, permeability anisotropy ratio, Young's modulus, and Biot's coefficient on surface uplift and pore pressure increase. Parameter estimation with 12 different sets of parameters is performed for both KB501 and KB503. Estimated sets of parameters and resulting pore pressure calculations are used to evaluate the significance of parameterization and the inclusion of the pore pressure constraint on the geomechanical response. It should be noted that the focus is on KB501 and KB503 and all of the simulations are based on these two injectors. Due to the complex nature of KB502 and many unknown factors involved in its surface uplift, this well will not be discussed in this study.