Impact of CO$_2$ induced mineral dissolution and precipitation on porosity and permeability of Lower Tuscaloosa and Marine Shale formations (Mississippi, USA): a numerical study

Liwei Zhang$^1$, Yan Wang$^1$, Xiaochun Li$^1$, Yee Soong$^2$, Robert Dilmore$^2$

$^1$State Key Laboratory of Geomechanics and Geotechnical Engineering, Institute of Rock and Soil Mechanics (IRSM), Chinese Academy of Sciences, Wuhan, 430071, China

$^2$US DOE/National Energy Technology Laboratory (NETL), Pittsburgh, Pennsylvania, United States

Abstract

A reservoir-scale numerical model is developed with the use of multi-phase reactive transport code TOUGHREACT to evaluate how CO$_2$-induced mineral dissolution and precipitation affect porosity and permeability of Lower Tuscaloosa (LT) sandstone formation and Marine Shale (MS) caprock overlying LT formation when CO$_2$ is injected into LT formation. The reservoir-scale numerical model is developed based on geological settings of LT and MS formations at Plant Daniel CO$_2$ storage test site, Mississippi, USA. LT formation is a deep saline aquifer and is a primary reservoir target for large-scale carbon dioxide injection due to its proximity to CO$_2$ sources, favorable depth, thickness, permeability, porosity, and the presence of overlying low permeability formations to seal the injected CO$_2$ from vertical migration into overlying formations. The average pressure of the LT formation is 23.8 MPa and the average temperature of LT formation is 85 °C, and the average thickness of LT formation is 36.5 m. The average thickness of MS caprock is 152 m. The reservoir-scale model simulates a 30-year CO$_2$ injection period with an injection rate of 1 million metric tons CO$_2$ per year, and a 970-year post CO$_2$ injection period.

Another core-scale reactive transport model is developed with the use of reactive transport code CrunchFlow to predict permeability evolution of small LT and MS samples (2.54 cm in diameter×5.08 cm in length) when exposed to CO$_2$-saturated brine in the laboratory for 180 days, and the permeability and solution chemistry results from the model are compared with experimental data to validate important modeling parameters (equilibrium constants ($K_{eq}$), reaction rate constants ($k$) and $n$ in the Verma-Pruess permeability-porosity relation) that are used in the reservoir-scale simulation.

The core-scale model predicts a permeability decrease from 2190 mD to 2038 mD for the LT sample after 180 days of exposure to CO$_2$ saturated brine, which is consistent with measured permeability results. The model predicts a significant permeability increase from 47 µD to 186 µD for the MS sample after 180 days of exposure to CO$_2$ saturated brine. Based on model prediction, key mineral dissolution and precipitation reactions in pore space of the LT sample include dissolution of chlorite and feldspar, and precipitation of amorphous silica (SiO$_2$, am), siderite (FeCO$_3$) and kaolinite. For the MS sample, dissolution of chlorite and feldspar is the main mineral dissolution process. Similar to the core-scale model, the reservoir-scale model predicts precipitation
of amorphous silica (SiO$_2$, am), siderite (FeCO$_3$) and kaolinite in the pore space of LT rock when interacting with CO$_2$-saturated brine. Dissolution of chlorite and feldspar is also predicted. However, due to strong pH buffering effect of LT formation, the amount of mineral precipitation and dissolution predicted by the reservoir-scale model is small after interacting with CO$_2$-saturated brine for 1000 years, and porosity and permeability changes of LT and MS formations caused by mineral precipitation/dissolution are minimal. In summary, porosity and permeability changes predicted by core-scale model and experiment can be different from those predicted by reservoir-scale model, due to large rock to water ratio in the reservoir-scale model. The large rock to water ratio leads to strong pH buffering effect, which is difficult to be reproduced by core-scale model and experiment.