Effects of adjacent mud rocks on CO_2 injection pressure: model case based on a typical U.S. Gulf Coast salt diaper field under injection

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Abstract:

Geological carbon storage aims at long-term storage of carbon dioxide (CO2) in deep geological formations to reduce anthropogenic CO2 emissions into the atmosphere. The viability of CO2 storage hinges on how much of the CO2 can be injected into the storage formation. However, the rate of CO2 injection can be limited by low injectivity of the storage formation and limits placed on the injection pressure to maintain seal integrity. Therefore, pressure evolution during CO2 injection is an important consideration for CO2 storage operation and is investigated in this study. We use geological characteristics of a typical oil field near a salt diapir in the Gulf Coast basin in the Southern United States. In this case CO2 is injected into a complex sedimentary rocks deposited in a fluviatile environment, juxtaposing volumes of high- and low-permeability rocks. The rock volume in which CO2 injection is taking place can be modelled, for the purpose of this study, as a simple reservoir surrounded by mud rocks which exhibit small, but finite, permeability and high compressibility. The mud rock is expected to behave as a capillary seal preventing upward CO2 migration, but may allow significant pressure dissipation. This pressure attenuation can be important from an operational standpoint as a fault in the vicinity of the injection well requires an accurate estimate of pressure evolution to avoid leakage along the fault.

Most numerical simulations of geological CO2 storage have focused on the behavior of fluids within a storage formation and assumed that overlying and underlying rocks are impermeable and incompressible. Such a reservoir model has immediate pressure buildup and drawdown corresponding to start and end of injection. Numerical simulations using reservoir parameters and a simple geomechanical model based on rock and fluid compressibilities were performed with the commercial simulator GEM from CMG. They show that overlying and underlying mud rocks attenuate pressure build-up within a reservoir during injection and extend the period of pressure recovery after the end of injection. The attenuation of pressure propagation within a target formation can reduce the probability of creation and/or reactivation of geological discontinuities. In addition, strong pressure gradients detected just outside the storage formation require high numerical resolution at the boundaries between the storage formation and mud rocks, otherwise extensive numerical diffusion will lead to unphysical pressure dissipation. It is therefore not just important to include the surrounding rocks but also to discretize them appropriately, and this is currently not standard practice.