Geophysical Research Abstracts
Vol. 12, EGU2010-12009, 2010
EGU General Assembly 2010

Injection of Super-Critical CO2 in Brine Saturated Sandstone:

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Presently, large-scale geological sequestration of CO2, originating from sources like fossil-fueled power plants and contaminated gas production, is seen as an option to reduce anthropogenic emission of greenhouse gases to the atmosphere. Deep saline aquifers and depleted oil and gas fields are potential subsurface deposits for CO2. Injected CO2, however, interacts physically and chemically with the formation leading to uncertainties for CCS projects. One of these uncertainties is related to a dry-out zone that is likely to form around the well bore owing to the injection of dry CO2. Precipitation of salt (mainly halite) that is associated with that drying out of a saline formation has the potential to impair injectivity, and could even lead to the loss of a well.
If dry (or under-saturated), super-critical (SC) CO2 is injected into water-bearing geological formations like saline aquifers, water is removed by either advection of the aqueous phase or by evaporation of water and subsequent advection in the injected CO2-rich phase. Both mechanisms act in parallel, however while advection of the aqueous phase decreases with increasing CO2 saturation (diminished mobility), evaporation becomes increasingly important as the aqueous phase becomes immobile. Below residual water saturation, only evaporation takes place and the formation dries out if no additional source of water is available.
If water evaporates, the salts originally present in the water are left behind. In case of highly saline formations, the amount of salt that potentially precipitates per unit volume can be quite substantial. It depends on salinity, the solubility limit of water in the CO2 rich phase, and on the ratio of advection and evaporation rates. Since saturations and flow rates cover a large range as functions of space and time close to the well bore, there is no easy answer to the questions whether, where and how salt precipitation impacts injectivity.

The present paper presents results of core-flood experiments that were performed to investigate the spatial and temporal precipitation of salt due to the injection of dry CO2 and to understand the underlying mechanisms; super-critical CO2 was injected into brine-saturated sandstone (Berea) samples under realistic pressure and temperature conditions and at high injection rate. To match flow rates that are realistic for the near well-bore area, the experiments were performed on small-scale samples with a cross section of less than 1 cm2. Density profiles were measured by mCT (micro computer tomography) scanning during injection. Reference scans and brine doping with a contrast agent allow the distinction between the CO2-rich phase, the aqueous phase and precipitated solid salt even on pore scale.
By means of mCT scanning, spatial and time evolution of halite precipitation in rock samples have been observed under sequestration conditions. Pattern formation of solid salt along the main flow direction as well as a cross-sectional pattern formation has been found. However, while there are areas of high local solid salt accumulation, permeability remained unaffected, which might be a result of the precipitation pattern.
The results were complemented by (ex-situ) eSEM/EDAX measurements to study where and how salt precipitates on the microscopic scale. The SEM results cannot be directly translated to in-situ conditions, as salt migrates post-experiment at ambient conditions, but give valuable insight into microscopic processes controlling deposition. Numerical simulations have been performed for a qualitative understanding of principle mechanisms and show a dependency of the observed profile on injection rate and capillary pressure.