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Well Injectivity during CO₂ Storage Operations in Deep Saline Aquifers

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SUMMARY

Geological sequestration of CO₂ in deep saline aquifers offers a promising solution for reducing net emissions of greenhouse gases into the atmosphere. This emerging technology based on massive CO₂ injection in deep saline reservoirs must cause dramatic physical and geochemical disequilibria of the host reservoir. Geochemical reactions and physical phenomena must generate strong perturbations of the initial state of the host reservoir. The consequences of near-wellbore drying-out on well injectivity through the evolution of the petrophysical properties of the porous medium were studied. The objective is to determine the key processes controlling the drying of the porous media during the injection of dry gas, and identify the repartition of the salt (dissolved and solid) in the cores submitted to the near well bore conditions (flow, temperature & pressure).

Introduction

Geological sequestration of CO₂ in deep saline aquifers offers a promising solution for reducing net emissions of greenhouse gases into the atmosphere. This emerging technology based on massive CO₂ injection in deep saline reservoirs must cause dramatic physical and geochemical disequilibria of the host reservoir. Geochemical reactions and physical phenomena must generate strong perturbations of the initial state of the the host reservoir. The consequences of near-wellbore drying-out on well injectivity through the evolution of the petrophysical properties of the porous medium were studied. The objective is to determine the key processes controlling the drying of the porous media during the injection of dry gas, and identify the repartition of the salt (dissolved and solid) in the cores submitted to the near well bore conditions (flow, temperature & pressure).

Methodology

The drying potential of a gas phase was studied in the laboratory on sandstone plugs (Peysson et al., 2014). These experiments were then interpreted using a numerical modelling approach coupling hydraulic, thermal and thermodynamic processes able to simulate the evolution of liquid and gas saturation in time and space (André et al., 2014). A very fine discretization of the plugs enabled us to capture the continuous evolution of water, gas and salt profiles in the multiphase porous medium and estimate the porosity and permeability variations during the drying process (Figure 1).

Figure 1 Peclet number vs. brine salinity allowing establish domains of clogging risks close to the injection well depending on the injection flow rate and capillary fluxes.

Conclusions

Numerical modelling is able to reproduce the experimental results of drying of brine-saturated sandstone cores by CO₂ injection at the laboratory scale. The evolution of water and gas saturation profiles and the precipitation of salt inside the samples were followed with injection time. The agreement between numerical results and laboratory observations highlights the key role played by capillary forces. A tentative extrapolation of experimental results to the near-well field scale is proposed. This finding is essential for the long-term management of gas injection into saline aquifers.

References

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