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## Thermo-fluid-dynamical modelling of salt precipitation during CO<sub>2</sub> injection in saline aquifers, and the effect on injectivity

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### Abstract

*CO<sub>2</sub> injection is a crucial part of CCS technology. To enable the injection and storage of many gigatonnes of CO<sub>2</sub> per year, a large number of injection wells are needed, and it is important to understand the physics of CO<sub>2</sub> injection in general and of salt precipitation in particular. Salt precipitation in the near-well region can lead to reduced permeability and subsequent reservoir damage. To be able to consistently model the salt precipitation, it is necessary to combine highly accurate equations of state (EoS) for the thermodynamic properties and phase compositions together with the fluid-dynamical models in a consistent fashion. The present work develops such a combination which enables the simulation of injection with analysis of the precipitation and injectivity loss, and thus makes possible parameter studies to identify the cases where precipitation is an operational risk.*

*Keywords:* CO<sub>2</sub> injection; salt precipitation; thermodynamics;

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### 1. Introduction

Safe and efficient CO<sub>2</sub> injection relies on a reservoir with sufficient injectivity and permeability. Experience from the Tubåen formation (Snøhvit) and other CO<sub>2</sub> injection sites has shown that the injectivity can be significantly reduced due to salt precipitation in the near-well region [1]. This is caused by water dissolving in the injected (dry) CO<sub>2</sub>, which leaves behind over-saturated brine, which in turn causes salt to precipitate. At Snøhvit, this meant that injection had to be stopped well before the reservoir storage capacity was reached. If the world is to meet the future CO<sub>2</sub> storage rates of more than 5 gigatonnes per year, as given e.g. in the IEA two-degree scenario [2], a large number of full-scale injection and storage operations must be conducted. Expected future CO<sub>2</sub> storage rates are comparable to natural gas production rates of today, which involves several hundred thousand wells worldwide. Prediction of how and when salt precipitation causes injection problems is essential to ensure safe and reliable injection.

Clogging of pores in the near-well region is a long-standing research topic, especially in the context of oil and gas production, and can be caused by a number of effects such as mineral/salt precipitation, hydrate/ice formation, filtrated mud particles and precipitation of asphaltenes. The particular case of salt precipitation during CO<sub>2</sub> injection for storage has received less attention, but some work has been undertaken using laboratory-scale experiments [4,5], larger field experiments [3] as well as reservoir flow simulations [6-9]. The latter has usually been done with simulators initially built for studying other phenomena such as nuclear waste disposal safety, where CO<sub>2</sub> injection capabilities have been added later. The models that are used for relating rock permeability to precipitation, as well as relative permeability to saturation, are highly sensitive to the numerical values of precipitation and saturation, and

thus it is crucial to have a model which gives highly accurate values for these quantities. If a consistent thermodynamic model can be used in simulations, high accuracy is obtained for all values of pressure, temperature, composition etc.

## 2. Models and methods

In this work, we develop a new approach to modelling CO<sub>2</sub> flow into a brine-filled reservoir using highly accurate thermodynamic models that consider both CO<sub>2</sub>, H<sub>2</sub>O and salts simultaneously. We consider the reservoir flow at close proximity to an injection well, where precipitation is most important for injectivity. We model the flow of the two separate fluid phases, one CO<sub>2</sub>-dominated and one brine-dominated, and we keep track of all components in each phase.

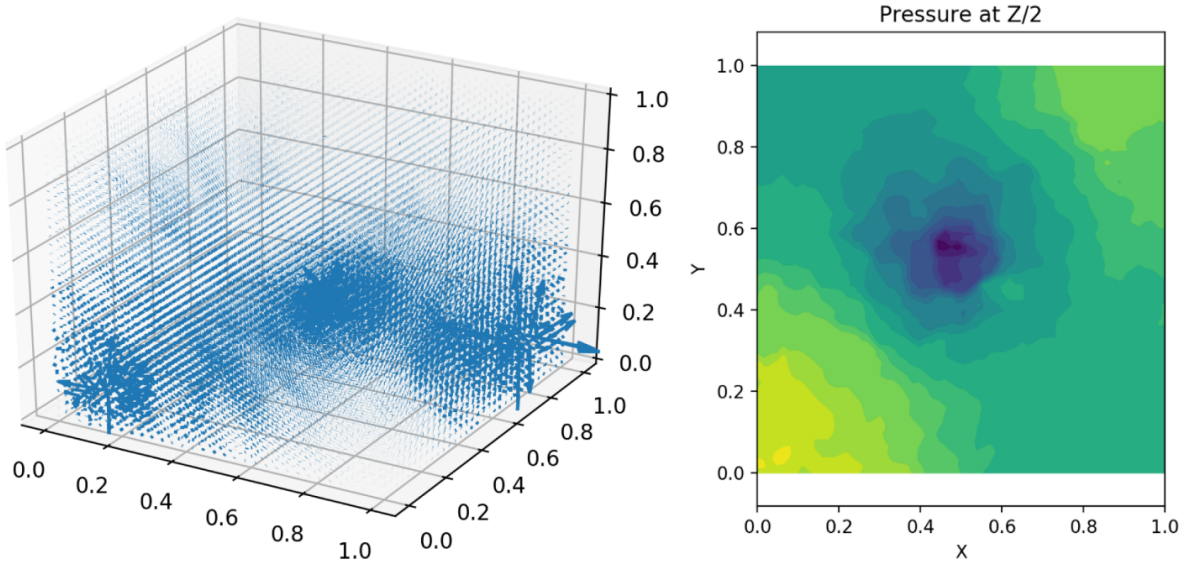


Figure 1: Velocities (left) and pressure distribution at the horizontal plane  $z=0.5$  (right) for a case with one injector and two producers, in a reservoir with highly varying permeability.

To achieve a thermodynamically consistent scheme for the fluid solver, we adapt the commonly used implicit pressure – explicit saturation (IMPES) scheme for porous media flow, but with a twist. We retain the usual pressure solution scheme at each time step, which computes the pressure field from the permeability and viscosity of the phases present, as shown in Fig. 1, according to the equation

$$\nabla \cdot (-\lambda \nabla p + (\lambda_c \rho_c + \lambda_w \rho_w) g \hat{z}) = \sum_{\alpha} \sum_l \frac{q_{l\alpha}}{\rho_{\alpha}}$$

where  $l$  is the index over components and  $a$  is the index over phases, and  $\lambda$  is the phase (or total when no subscript is given) mobility. The phase mobilities are given as

$$\lambda_{\alpha} = \mathbf{K} \frac{k_{r\alpha}}{\mu_{\alpha}}$$

Where the present approach has a twist on the IMPES approach is that after the pressure has been solved, instead of

solving next the transport equations for saturation, we solve the total mass transport equations for each component present (CO<sub>2</sub>, water, salts) per phase, i.e.

$$\phi \frac{\partial}{\partial t} m_{l\alpha} + \nabla \cdot \left( m_{l\alpha} \frac{\mathbf{u}_\alpha}{s_\alpha} \right) = q_{l\alpha}$$

From this information, we can perform a thermodynamic calculation known as a multiphase pressure-temperature-composition (PTz) flash, which yields the saturation and the densities of the two fluid phases. This approach gives a thermodynamically consistent formulation of the system, at the cost of increased computational cost in the flash calculation as compared to existing, simpler approaches.

The mass of solid (precipitated) salt is given by the thermodynamic calculations and is subsequently used to update the rock permeability according to the model by Pruess and Muller [9]. For the relative permeabilities, we employ the van Genuchten model

$$\begin{aligned} k_{rw} &= \sqrt{s_1} \left( 1 - (1 - s_1^{1/\lambda})^\lambda \right)^2 \\ k_{rc} &= (1 - s_2)^2 (1 - s_2^2) \\ s_1 &= (s_w - s_{rw}) / (1 - s_{rw}) \\ s_2 &= (s_w - s_{rw}) / (1 - s_{rw} - s_{rc}) \end{aligned}$$

using values for the exponents and residual saturations as given by Williams et al. [12] as representative of the Utsira sandstone.

The fluid properties are given by accurate property models and Equations of State (EoS). In our thermodynamic formulation, the electrolyte CPA (eCPA) EoS [10-11] is used to describe phase equilibrium and densities. eCPA extends the CPA model with a Debye-Hückel model for electrostatic interaction and the Born term for hydration energy. The eCPA model consistently describes all the fluid phases. The precipitated salt phases are predicted using Gibbs free energy EoSs.

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