Waterflooding for improved oil recovery: cation exchange makes the difference

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Waterflooding is a common technique to improve oil recovery. Injecting water into producing reservoirs helps maintaining pressure and improves oil mobilisation in the pores. The displacement efficiency depends on several factors, such as oil viscosity, rock characteristics, the formation water (FW) composition, and the injected water (IW) composition, typically seawater (SW) for offshore fields. The FW and IW compositions can be very different. Incompatibility of FW and IW can result in production threats such as salt deposition (scaling), which is of interest as it can impair near-wellbore permeability and reduce well productivity/injectivity. Differences in FW and IW compositions can also lead to cation exchange with clay minerals in the reservoir, but relatively less is known on the impact of this process on scaling. In this paper we use reactive transport modelling (RTM) to assess such impact for a number of oil-producing fields.

We carried out RTM using our in-house reservoir simulator (MoReS), which is coupled to the open-source geochemical software program PHREEQC. For various oil-producing fields we used simplified (1D/2D) and more complex (3D) models, with varying FW and SW compositions to simulate water injection and production. Cation exchange equilibrium constants are based on experimental data.

We observe fair agreement with measured changes in produced water chemistry over time, which significantly improves when cation exchange with clay minerals is taken into account. Oversaturation of mostly barite and calcite is predicted. Depending on the flow geometries (mixing of streamlines), scaling is predicted deep in the reservoir, in the near-wellbore area of the producer, and/or in the production system. The developed methods and results will be used in future projects to forecast scale risk, and in the selection and timing of scale mitigation technologies (e.g. scale squeezes).