Numerical Investigations of CO_2 Sequestration in Geological Formations: Problem-Oriented Benchmarks

Problem 3: “Estimation of the CO_2 Storage Capacity of a Geological Formation”

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1 Introduction

The estimation of the amount of CO_2 which a given formation can safely store is an important issue which has to be addressed before the injection of CO_2 into a storage formation. An overestimation could lead to leakage and an underestimation would result in a waste of CO_2 storage potential. To properly estimate storage capacity with numerical simulations, models would have to be able to simulate the CO_2 injection and its subsequent migration in the formation dominated by the pressure gradient due to the injection. They also have to be capable of properly modelling the CO_2 spreading after the injection has been stopped and the main driving force is gravity or capillarity. Other processes such as CO_2 dissolution in formation brine, hysteresis, temperature changes or mineral precipitation could also be important aspects that need to be investigated by models.

2 Problem Description

Figure 1 shows part of the Johansen formation off the coast of Norway. The model domain has been extracted from the much larger formation. The extracted part contains a fault zone and the injection well is located near the fault. This obviously would be avoided in a CO_2 storage project. In this study, it is however intended to have leakage conditions in order to discuss storage capacity issues.

The domain's lateral dimensions are approximately 9600 m × 8900 m. The formation thickness varies between about 90 m and 140 m. Geometry, porosity and permeability of the formation can be downloaded from the website

http://www.iws.uni-stuttgart.de/co2-workshop/

and are based on a study by the Norwegian Petroleum Directorate[4]. CO_2 is to be injected into the formation over the bottom 50 m of an injection well located at $x = 5440\,\mathrm{m}$ and $y = 3300\,\mathrm{m}$. 15 kg/s is injected over ~~15~~ **25 years (correction: 17th January, 2008)** after which the well is shut down. The total simulation time is 50 years at the end of which some amount of CO_2 would have escaped over the open boundaries of the domain. The aim of this problem is to determine the amount which is stored and to identify the involved trapping mechanisms i.e. the amounts of dissolved CO_2 in water and CO_2 still in phase.

[4] Report entitled "Beslutningsgrunnlag knyttet til transport deponering av CO_2 fra Kårstø og Mongstad" available on *http://www.gassnova.no/graphics/GASSNOVA/Download/rapport_20.09.07.pdf*

Two cases are distinguished.

- Problem 3.1 neglects effects of hysteresis.
- Problem 3.2 takes hysteresis of the CO_2 relative permeability-saturation relationship into account by the model given below.

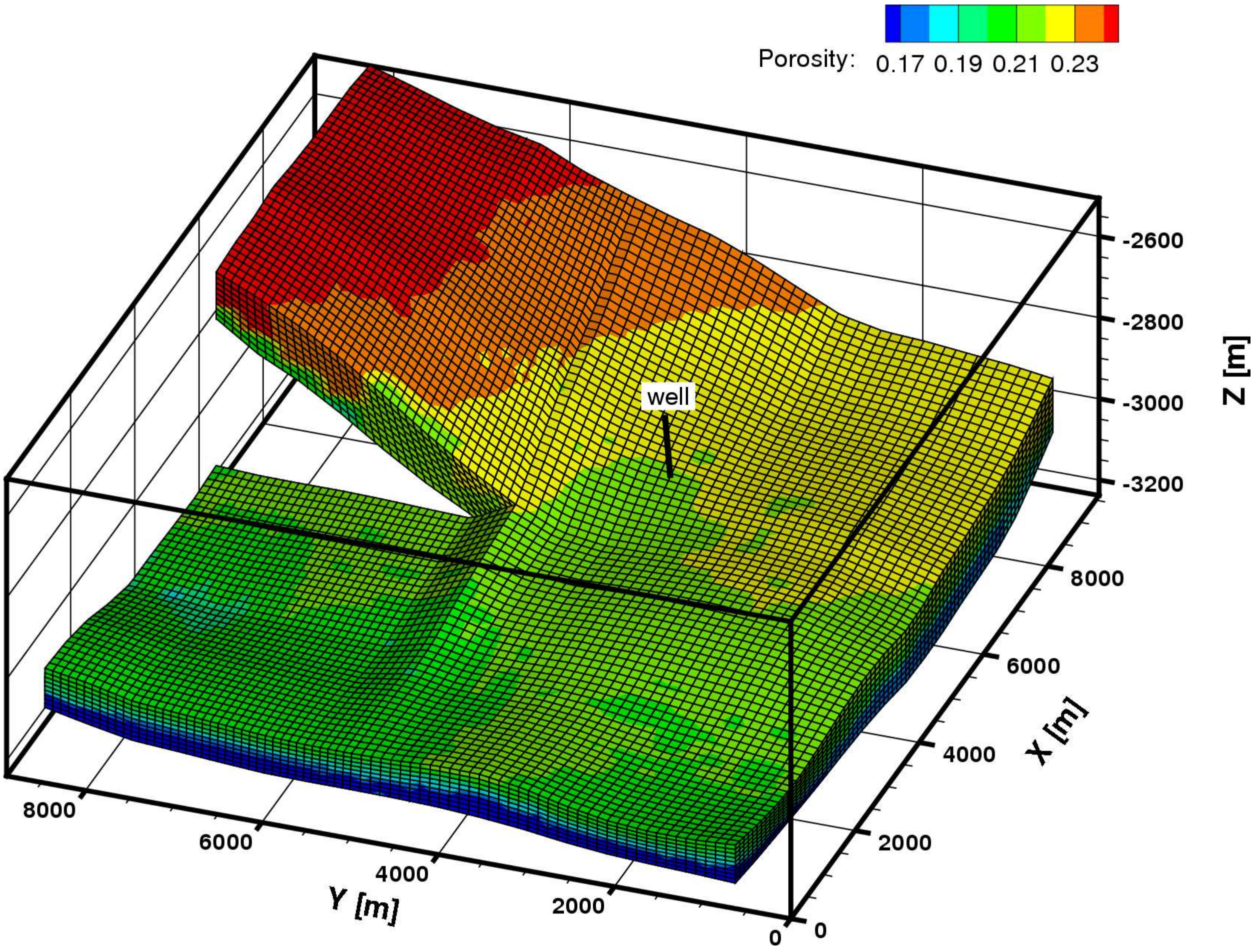

Figure 1: Porosity distribution of the geological formation into which CO_2 is to be injected. The injection well with the coordinates $x = 5440\,\mathrm{m}$, $y = 3300\,\mathrm{m}$ is also shown.

Hysteresis model for Problem 3.2 The hysteresis in the CO_2 relative permeability-saturation relationship is accounted for using the model given in Land (1968). The Land trapping parameter is chosen to be $C = 0.75$ (see also Spiteri (2005)). Some simplifying assumptions for this problem are given below. Capillary trapping and its effect on mobility has been described by Juanes et al. (2006). They conclude that the amount of CO_2 that is immobilised by capillary trapping can be quantified by modelling the relative permeability hysteresis.

- Only one hysteresis cycle is modelled i.e. only one drainage and one imbibition curve.
- The hysteresis in the relative permeability-saturation relationship of water is negligible.

Table 1: Capillary pressure and (drainage) relative permeability parameters. These can be assumed to be constant. Note that Problem 3.2 accounts for hysteresis of the CO_2 relative permeability-saturation relationship.

Parameter	Value
Residual brine saturation	0.2
Residual CO_2 saturation	0.05
Relative permeability	Brooks and Corey (1964)
Capillary pressure	Brooks and Corey (1964)
Entry pressure	10^4 Pa
Brooks-Corey parameter λ	2.0

Initial and Boundary Conditions

The initial conditions in the domain include a hydrostatic pressure distribution which is dependent on the brine density and a geothermal temperature distribution dependent on the geothermal gradient. The geothermal gradient is assumed to be 0.03 K/m and the initial temperature at 3000 m depth is 100 °C. The entire formation is initially filled with brine. The lateral boundary conditions are constant Dirichlet conditions and equal to the initial conditions. This also holds for the faces of the fault which is intended to represent an infinitely permeable fault. The top and bottom boundaries are no-flow boundaries.

CO_2 is injected at a constant rate of 15 kg/s over a period of ~~15~~ **25 years** (**correction: 17th January, 2008**). It is assumed that the CO_2 is injected at a constant temperature of 80 °C. The total simulation time is 50 years. Fluid properties are dependent on temperature T, pressure p, brine salinity $S = 0.1$ kg/kg and CO_2 mass fraction in brine X_w^{CO2}.

3 Output

The output of interest comprises for both cases the following:

- the mass of CO_2 in the formation over time, thereby distinguishing between CO_2 in phase and dissolved CO_2 in brine,

- the total leakage (in kg/s) over time across the Dirichlet boundaries,
- pictures (JPEG or similar) of the top view of the formation showing the isolines (0.2, 0.5 and 0.8) of CO_2 saturation after 1, ~~15~~ **25** (**correction: 17th January, 2008**) and 50 years.

References

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