

Evaluation of CO₂ Leakages from an Aquifer Storage

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Abstract: This paper presents preliminary estimations of CO₂ overpressure into the reservoir and CO₂ leakage through the caprock and the overburden. A simple, two-phase flow model in porous media based on Darcy's law was used, in order to explore easily long time periods. The models allow sensitivity studies and preliminary evaluations of the relations between CO₂ leakage (time needed for the CO₂ to reach the surface; value of the CO₂ flowrate at the steady state), the caprock characteristics (thickness and permeability) and CO₂ overpressure.

Keywords: CO₂ geological storage, 2-phase flow, gas leakage.

1. Introduction

The capture and storage of carbon dioxide (CO₂) underground appear as one way to reduce atmospheric greenhouse gases, often associated with global warming. Risk assessments have to be done to demonstrate the long-term integrity of the storage. The risk analysis developed by INERIS ([Gombert et al., 2009], [Farret et al., 2010]) is first based on the definition of scenarios that link initiating causes (ex: CO₂ overpressure), central events (ex: loss of confinement of the reservoir) and impacting phenomena (ex: diffuse CO₂ leakage at the surface). The second step aims to evaluate the probability of occurrence and the severity of the impacting phenomena. For that purpose, the use of numerical modeling can be a precious help.

The variety of the physical and chemical phenomena induced by CO₂ geological storage lead us to divide (as far as possible) the global system into smaller sub-systems that could be, later on, recombined. For each question and each sub-system a specific modeling exercise is performed.

In this paper, two models are presented. The first one aims to evaluate the fluid pressure increase due to CO₂ injection into an aquifer reservoir. The second one proposes a preliminary evaluation of the CO₂ leakage from the reservoir through the overburden. In both case COMSOL is used to simulate the CO₂ and water flows.

2. Simulation of two-phase flow with COMSOL

A two phase flow model had already been developed into COMSOL. It was used to simulate CO₂ leakage from an underground storage ([Houdu et al., 2008], [Freeman et al., 2008]). Our preliminary contribution was to include CO₂ compressibility into this model.

The results presented in this paper are based on the assumptions that the CO₂ flows through the porous rockmass do not significantly interact with the chemical, mechanical and thermal processes. More complex models are currently developed to evaluate those assumptions.

Two-phase flow in porous media follows separate equations for the wetting (w) and non-wetting (nw) fluids (taking into account the fluid compressibilities):

$$\theta_s \left[\frac{\theta_w}{K_w} \frac{\partial p_w}{\partial t} + \frac{\partial Se_w}{\partial t} \right] + \nabla \left[- \frac{\kappa_{int} \cdot kr_w}{\mu_w} \nabla (p_w + \rho_w \cdot g \cdot z) \right] = 0 \quad [1]$$

$$\theta_s \left[\frac{\theta_{nw}}{K_{nw}} \frac{\partial p_{nw}}{\partial t} + \frac{\partial Se_{nw}}{\partial t} \right] + \nabla \left[- \frac{\kappa_{int} \cdot kr_{nw}}{\mu_{nw}} \nabla (p_{nw} + \rho_{nw} \cdot g \cdot z) \right] = 0 \quad [2]$$

where: θ_s is the total porosity; θ_w and θ_{nw} are the volume fraction for the wetting and non-wetting fluids ($\theta_w + \theta_{nw} = \theta_s$); Se_w and Se_{nw} are the effective saturation ($Se_w + Se_{nw} = 1$); t is time [s]; κ_{int} is the intrinsic permeability of the porous medium [m²]; kr_w and kr_{nw} are the relative permeabilities; μ_w and μ_{nw} are the fluid's dynamic viscosities [kg/m/s]; p_w and p_{nw} are the fluid pressures [kg/m/s²] ($p_c = p_{nw} - p_w$ is the capillary pressure); ρ_w and ρ_{nw} are the fluid densities [kg/m³]; K_w and K_{nw} are the fluid compressibilities [MPa]; g is acceleration of gravity; and z is the depth [m].

To solve this set of equations, some others relations have to be defined between the various parameters:

$$\theta_w = \theta_{rw} + Se_w(\theta_s - \theta_{rw}) \quad [3]$$

$$Se_w = \frac{1}{\left(1 + ((\alpha/\rho_w \cdot g) \cdot p_c)^{\frac{1}{1-a}}\right)^a} \quad [4]$$

$$kr_w = Se_w^b \left(1 - \left(1 - Se_w^{\frac{1}{a}}\right)^2\right) \quad [5]$$

$$kr_{nw} = (1 - Se_w)^c \left(1 - Se_w^{\frac{1}{a}}\right)^{a^2} \quad [6]$$

where: θ_{rw} is the residual volume fraction for the wetting fluid and α , a , b , and c are the van Genuchten parameters.

The fluids characteristics (density, viscosity, compressibility) are assumed to be temperature and pressure dependent ([Fenghour et al., 1998]), Assuming that the temperature and average fluid pressure are linearly increasing with depth z ($\Delta T = 3^\circ\text{C}$ and $\Delta P = 1 \text{ MPa}$ for each 100 m of overburden), simple relations have been used to link the fluid characteristics to z . At the surface, where the assumed temperature is 15°C , $\rho_{\text{CO}_2} = 1.8 \text{ kg/m}^3$, $\mu_{\text{CO}_2} = 14.4 \cdot 10^{-6} \text{ Pa.s}$, $K_{\text{CO}_2} = 0.1 \text{ MPa}$; at the reservoir roof, at -1500 m, the temperature is 60°C and $\rho_{\text{CO}_2} = 605 \text{ kg/m}^3$, $\mu_{\text{CO}_2} = 47.2 \cdot 10^{-6} \text{ Pa.s}$, $K_{\text{CO}_2} = 16.0 \text{ MPa}$. According to pressure and temperature conditions, the CO_2 state changes from supercritical to gas 700 m below the surface.

3. Simulation of the CO_2 injection into the reservoir (model 1)

The objective of the simulation is to evaluate the fluid pressure variation induced by a CO_2 injection into the reservoir.

The reservoir is assumed to be a layer of permeable limestone ($k_{\text{int}} = 10^{-13} \text{ m}^2$), 100 m thick, surrounded by 2 layers of mudstone (caprock). The reservoir roof is located 1500 m deep. Considering the small caprock permeability (about 10^{-17} m^2), the model geometry has been simplified and the layers surrounding the reservoir have been replaced by zero flux boundary conditions. We will see, in section 4,

that the assumption is acceptable because, in any case, the CO_2 leakages through the caprock remain small and do not significantly impact the CO_2 flow into the reservoir.

The reservoir is assumed to be initially fully saturated with water. We have simulated an injection of 350000 tons of supercritical CO_2 per year during 10 years. This injection is distributed along all the reservoir height. The injection well is assumed to be on the left side of our 2D axial symmetry model. On the right side of the model (located 10 km from the injection well) constant pressure boundary conditions are assumed.

In this model, we have chosen not to take into account the CO_2 dissolution in water, and the other chemical, mechanical and thermal processes. This means that, for the present study, the wetting (water) and non wetting fluid (CO_2) are assumed immiscible and at the same temperature (about 60°C , the rock mass temperature at 1400 m deep). This evaluation of the impact of these simplifications are the goal of others on-going studies.

The others input data needed are: $\theta_s = 0.15$, $\theta_{rw} = 0.04$, $a = 0.66$, $b = 0.5$, $c = 0.9$, $\alpha = 0.0982$. The van Genuchten parameters come from a characterization of the Lavoux limestone [Egermann et al., 2005].

Figure 1 shows the variation of water effective saturation into the reservoir during the injection period (at 1, 2, 6 months, 2 and 10 years) and after (at 100 and 1000 years). The injected CO_2 concentrates at the reservoir roof because of gravity effect.

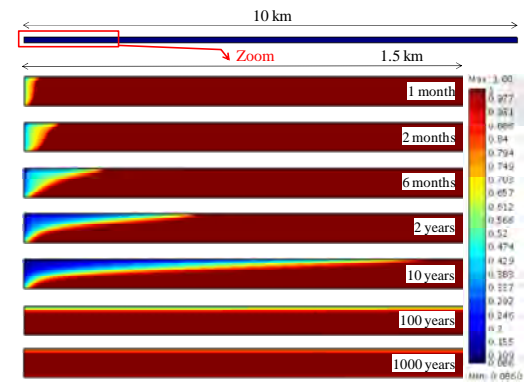


Figure 1. Iso-values of water effective saturation computed with model 1 during CO_2 injection phase ($0 < t < 10$ years) and after ($10 < t < 1000$ years)

After 10 years, one can see on figure 2 that the effective water saturation decreases from 1 to its minimal value (0.1 close to the well). After the end of injection, the CO₂ continues to migrate far from the well. The global quantity of CO₂ into the reservoir remaining constant (after 1000 years, the CO₂ front has not reached the right side of the model that is 10 km from the injection well), the effective water saturation begins to increase (up to 0.7 after 1000 years for the previous desaturated zone).

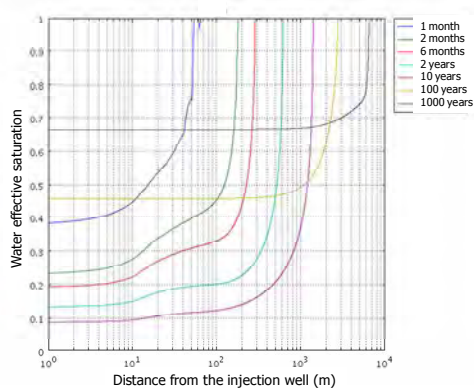


Figure 2. Horizontal profiles of water effective saturation at the reservoir roof at various times from 1 month to 1000 years

The injection of CO₂ induces an increase of the CO₂ pressure p_{nw} . The maximum of CO₂ overpressure (1.2 MPa) is reached after a few months in the vicinity of the injection well.

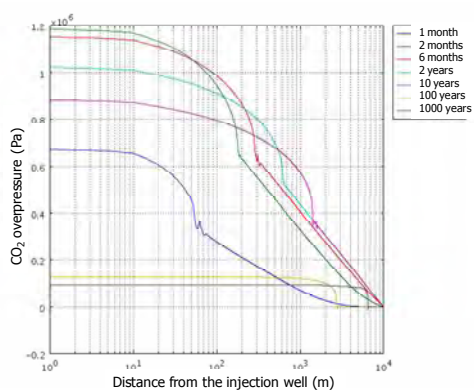


Figure 3. Horizontal profile of CO₂ overpressure at the reservoir roof at various times from 1 month to 1000 years

This maximum value decreases with the distance from the well (figure 3) and with time (figure 4). At the end of the injection phase, the CO₂ overpressure rapidly drops below 0.2 MPa.

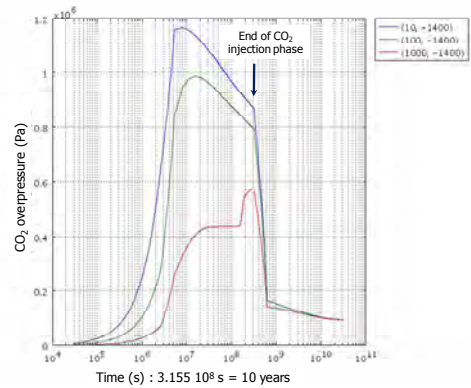


Figure 4. Evolution of CO₂ overpressure with time at the reservoir roof at 3 distances from the injection well (10 m, 100 m and 1000 m)

The water pressure p_w also increases due to CO₂ injection ($p_w = p_{nw} - p_c$). The maximum value is smaller (1.0 MPa) and is reached sooner. Figure 5 shows that, at a point located 10 m from the injection well, p_w reaches the maximum after 2 months, so 3 week before the p_{nw} peek.

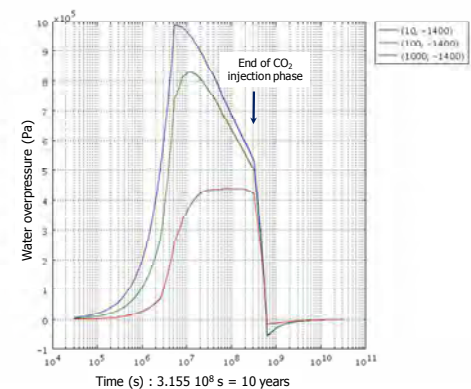


Figure 5. Evolution of water overpressure with time at the reservoir roof at 3 distances from the injection well (10 m, 100 m and 1000 m)

5. Simulation of the CO₂ leakage through the overburden (model 2)

To evaluate the CO₂ leakage from the reservoir through the overburden, another model is proposed. The objective of the simulation is to evaluate the time needed for the CO₂ to reach the surface and the value of the CO₂ flowrate at the steady state.

This model assumes that the overburden consists in a low permeability layer (caprock) just above the reservoir and a layer of higher permeability between the caprock and the surface. The overburden is initially fully saturated with water.

The fluid flows (CO₂ and water) are assumed to be vertical (no flux on lateral boundaries). Constant pressure conditions are applied on the horizontal boundaries ($P_w = P_{nw} = P_{atm}$ at the surface; $P_w = \rho_w \cdot g \cdot h + P_{atm}$ and $P_{nw} = P_w + \Delta P_{nw}$ at the caprock basement (or reservoir roof) where $h = 1500$ m and ΔP_{nw} the CO₂ overpressure due to the CO₂ injection into the reservoir.

We have defined a reference case considering a caprock thickness = 100 m, a caprock intrinsic permeability = 10^{-17} m² and an applied overpressure $\Delta P_{nw} = 1$ MPa. The other input data needed to define the flows through the caprock are: $\theta_s = 0.06$, $\theta_{rw} = 0.02$, $a = 0.33$, $b = 0.5$, $c = 1.7$, $\alpha = 0.37$ (the van Genuchten parameters come from a characterization of Bure mudstone [Hoxha, 2004]).

This overpressure is assumed to be constant during all the whole simulation. This latter assumption is clearly very conservative (section 3 shows that the CO₂ overpressure decreases rapidly after the end of the injection phase) and leads to overestimate the CO₂ leakage.

Figure 7 shows the variation of water effective saturation into the overburden up to 10000 years for the reference case. The minimal value of water effective saturation is = 0.866 in the caprock.

Considering the flow continuity at the interface between the 2 layers (and the permeability ratio), it is logical that the maximal desaturation of the permeable layer is far less important (= 0.995).

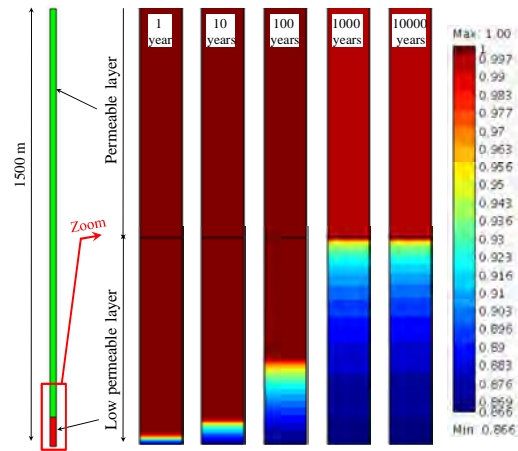


Figure 7. Iso-values of water effective saturation (model 2 - reference case)

For the reference case, steady state is reached after about 2000 years (figure 8). CO₂ appears close to surface after about 1200 years (before the water effective saturation is still equal to 1).

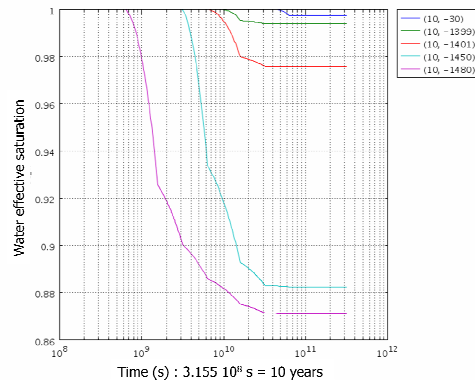


Figure 8. Evolution of water effective saturation with time at 5 depths (model 2 - reference case)

The water velocity in the entire model begins to increase as soon as the CO₂ injection starts (figure 9). Indeed, the injected CO₂ induces a water pressure increase close to the well that causes the water flow. After about 1 year, the water velocity reaches a maximum and then begins to decrease slowly.

The CO₂ velocity logically remains equal to zero in all parts of the model still fully saturated with water. It begins to increase at a given point as soon as the effective water saturation begins to decrease at that point (figure10).

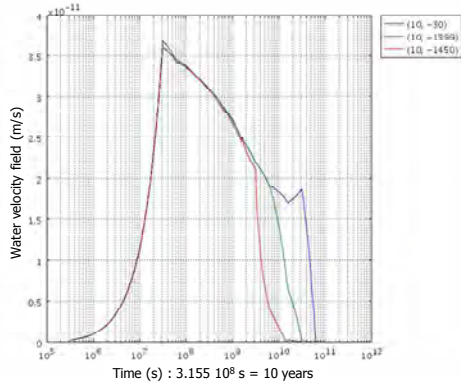


Figure 9. Evolution of water velocity field with time at 3 depths (model 2 - reference case)

Steady state is reached in the entire model after about 2000 years. For the reference case, the CO₂ velocity then equals $1.9 \cdot 10^{-11}$ m/s which amounts to a volumetric flow rate (volume of fluid which passes through a unit surface per unit time) of $6.0 \cdot 10^{-4}$ m³ per square meter and per year.

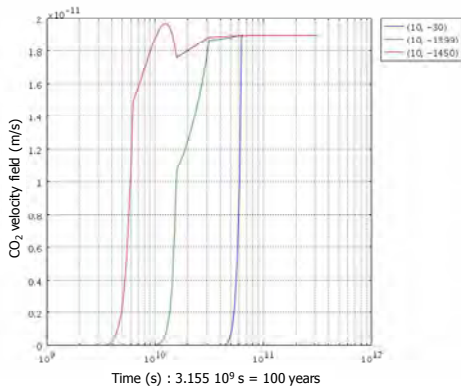


Figure 10. Evolution of CO₂ velocity field with time at 3 depths (model 2 - reference case)

To evaluate the impact of the caprock intrinsic permeability k_{int}^{cap} and thickness h^{cap} , as well as the applied overpressure ΔP_{CO_2} , on the results a first sensitivity study has been carried out. Table 1 provides, for each run, the time needed for the CO₂ to reach the surface ($t_{CO_2}^{surface}$) and the volumetric flow rate at the steady state ($q_{CO_2}^{surface}$).

A variation of one order of magnitude of the caprock intrinsic permeability leads to 3 orders

of magnitude difference on the volumetric flow rate. The time needed for the CO₂ to reach the surface is also strongly affected by the caprock intrinsic permeability.

Table 1: Results of the sensitivity study (model 2)

	k_{int}^{cap} [m ²]	h^{cap} [m]	ΔP_{CO_2} [MPa]	$t_{CO_2}^{surface}$ [year]	$q_{CO_2}^{surface}$ [m ³ / year/m ²]
Ref.	10^{-17}	100	1	1188	$6.0 \cdot 10^{-4}$
Var 1	10^{-18}	100	1	300000	$3.5 \cdot 10^{-7}$
Var 2	10^{-16}	100	1	125	$2.4 \cdot 10^{-1}$
Var 3	10^{-17}	100	0.5	2345	$6.3 \cdot 10^{-5}$
Var 4	10^{-17}	100	2.5	285	$8.3 \cdot 10^{-3}$
Var 5	10^{-17}	100	5.0	122	$4.3 \cdot 10^{-2}$
Var 6	10^{-17}	50	1	586	$8.7 \cdot 10^{-4}$
Var 7	10^{-17}	200	1	2250	$4.9 \cdot 10^{-4}$
Var 8	10^{-17}	400	1	2757	$4.5 \cdot 10^{-4}$

Reducing the applied CO₂ overpressure to 0.5 MPa doubles the migration time of the CO₂ through the overburden and divides the volumetric flow rate by 10. On the opposite, an increase of the overpressure to 5 MPa divides $t_{CO_2}^{surface}$ by 10 and multiplies $q_{CO_2}^{surface}$ by 7.

The increase of the caprock thickness logically increases $t_{CO_2}^{surface}$ and reduces $q_{CO_2}^{surface}$. However this impact tends to become smaller for a thickness higher than 200 m.

In order to evaluate the effect of considering a constant CO₂ overpressure during the simulation, a last run have been done with a time-dependent CO₂ overpressure applied at the caprock basement. The CO₂ overpressure variations with time have already been calculated with model 1. From the results depicted on figure 4, we have built the red curb given on figure 11. Considering this variation, model 2 shows CO₂ needs 5 times longer (than the reference case) to reach the surface. After about 1000 years, the volumetric flow rate reaches a maximum about 140 times smaller than the volumetric flow rate reached at steady state for the reference case.

This confirms that apply a constant CO₂ overpressure during all the whole simulation are clearly conservative and leads to strongly overestimate the CO₂ leaks through the overburden.

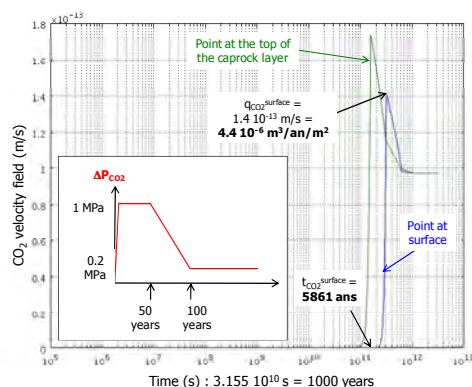


Figure 11. Evolution of CO₂ velocity field with time at the top of the caprock layer and at surface (model 2 with time-dependent CO₂ overpressure)

6. Conclusions

This paper is a preliminary contribution to a long term evaluation of CO₂ storage integrity. COMSOL simulations allow an estimation of the fluid pressure variations into the reservoir due to CO₂ injection. The volumetric flow rate of CO₂ through the overburden has also been computed as a function of CO₂ overpressure into the reservoir and the caprock intrinsic permeability and thickness.

The model attempts to take into account the strong variations of CO₂ density, viscosity and compressibility from the reservoir to the surface. However we still need to check if the set of equations used to solve the two phase flows (and previous developed for constant fluid properties) has to be updated to better simulate the impact of these variations.

Numerous phenomena have been neglected as the CO₂ dissolution in water, the related chemistry and the interaction with thermo-mechanical processes. These models are currently being developed in INERIS in order to be able to confirm or improve the preliminary results presented in this paper.

The use of such a numerical model to estimate transfer and other processes is of course of great help in the frame of risk analysis. The risk analysis consists of identifying relevant scenarios and estimating both their likelihood and their consequences. In this frame, the numerical model will first allow to understand the underground processes and confirm or infirm

the likelihood of risk scenario. Secondly, the quantitative result of the model allows estimating the intensity of the CO₂ flow towards the surface or aquifers, and therefore its possible consequences. In this respect, it will be of course important to use conservative options in the model, or to estimate its uncertainty.

7. References

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