Hydraulic barrier design and applicability for managing the risk of CO2 leakage from deep saline aquifers

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Abstract

A proper risk management scheme for CO_2 storage should include an adequate monitoring plan completed with a site-specific intervention plan in order to demonstrate that any undesired consequence can be prevented, if not corrected. In the case of CO_2 escape from the storage reservoir to an overlying aquifer through a vertical conduit (representing the degraded cement of a well or a permeable fault), directly modifying the leak hydraulic properties (e.g. permeability) may be unfeasible. An appealing option is to counter the driving forces of the migration (natural CO_2 buoyancy and injection-induced over-pressure) by increasing the pressure over the leak through brine or water injection within the overlying aquifer, i.e. by creating a "hydraulic barrier". The present article presents and discusses the operational and strategic issues associated with this corrective technique and proposes a methodology in order to set the main design parameters (injection flow rate and duration) depending on the site specificities. The methodology is tested on a leakage scenario and three implementation cases of hydraulic barriers (brine injection 10 m away from the leak with or without delay, or 1 km away without delay) are simulated using the 3D multiphase flow transport code TOUGH2/ECO2N. We assess their effectiveness for stopping the leakage and for trapping (residual and dissolution) the CO_2 accumulated in the overlying aquifer. This example shows that the hydraulic barrier can be suited to low transmissivity overlying aquifers, and that its effectiveness will primarily depend on the distance from the leak to the brine injection well. When possible, a brine injection within the overlying aquifer formation in the vicinity of the leak ensures a rapid stop of the leakage and an effective trapping of the CO_2.

Keywords

CO_2 geological storage, hydraulic barrier, leakage, risk management, corrective measure, remediation

1. Introduction

CO_2 capture and geological storage (CCS) is under serious consideration by governments and industry in order to achieve large reduction in atmospheric anthropogenic greenhouse gases emissions. Depleted oil and gas fields and saline aquifers are seen as possible storage reservoirs, the latter

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offering more opportunities for future industrial developments (IPCC, 2005). But a prerequisite to CCS large scale industrial developments is the demonstration by the operators that the containment is effective and that the storage is safe (IEA-GHG, 2007a). In this view, an integrated safety strategy should both rely on site-specific risk assessment and on appropriate monitoring plans during and after the CO_2 injection period.

Nevertheless, any industrial activity is confronted with residual risk and operators need to know what can be done in case of abnormal behavior of the CO_2 in the reservoir as outlined by the recently issued directive of the European Commission on CO_2 storage operations. This states that the storage permit shall contain an approved “corrective measures” plan (EC, 2009, article 16); a corrective measure being “any measures taken to correct significant irregularities or to close leakages in order to prevent or stop the release of CO_2 from the storage complex” (EC, 2009, article 3, definition 19). Therefore, a proper risk management scheme should also be completed with a site specific intervention plan in order to demonstrate that any undesired consequence can be mitigated.

CO_2 is injected in supercritical state such that the density contrast with the host reservoir brine ranges from 10% to 40% depending on the pressure and temperature conditions. Thus, driven by buoyancy forces, CO_2 may naturally escape through any zone of high permeability (e.g. faulty area) or any artificial pathways (e.g. abandoned wells). In addition, the injection operation leads to the over pressurization of the host reservoir, which is an additional driving force for the leakage. In the present article we consider the case in which CO_2 accumulates in an overlying aquifer as a gaseous plume (composed of supercritical CO_2 and a small fraction of gaseous water. It will be named “gaseous CO_2” in this article in order to enhance its main composition and the opposition with the liquid brine).

Different remediation strategies can be deployed in case of leakage, either (i) by acting on the root causes of the leakage (e.g. controlling the overpressure within the reservoir, Le Guénan & Rohmer 2011, or relying on the enhancement of the CO_2 immobilization through dissolution and residual trapping, Qi et al. 2009; Manceau et al. 2011) or (ii) by modifying the leak hydraulic properties (e.g. on the leak permeability) relying for instance on techniques developed for repairing leaky wells based on the past experience of the oil and gas industry (IEA-GHG, 2007b).

Nevertheless, directly modifying the leak hydraulic properties may be hardly practicable for most of the natural leakages (e.g. permeable faults), as discussed in section 2.3. In this regard, we investigate a third strategy consisting in the application of the “hydraulic barrier” technique which was introduced as a corrective measure for CO_2 geological storage in Réveillère & Rohmer (2011). In this article we extend the approach by considering the applicability of the technique and proposing a methodology in order to set its main design parameters: the necessary brine injection duration and flow rate.

This article first describes a possible risk management strategy in case of leakage: detection, localization and correction. The role of the hydraulic barrier as a corrective measure is discussed regarding different cases of leakage (Section 2). In Section 3, a generic scenario of CO_2 leakage from a storage aquifer to an overlying one is introduced and simulated. Section 4 proposes a methodology for setting the main design parameters of the hydraulic barrier and applies it to the generic leakage scenario. In the 5th section, three hydraulic barriers designed using the proposed methodology are simulated and their effectiveness is investigated.

2. Intervention plan for managing a CO_2 leakage into an overlying aquifer

After the leakage detection (first step), the leak should be located and characterized (second step) in order to analyze the event and the associated risk, and to investigate the applicability of different possible corrective actions (third step).

2.1. Leakage detection

The first step of risk management is to detect events deviating from the "normal" behavior of the storage complex (named "abnormal behavior" in the European directive, EC, 2009). For the event considered, this implies detecting the escape of CO_2 from the storage aquifer and its accumulation within the overlying aquifer. In the case of secondary trapping in an overlying aquifer, seismic and pressure monitoring methods are considered to be the best developed detection techniques (Benson, 2006).

When equipped with pressure transducers, the wells located within the overlying aquifer (seen as a monitoring aquifer) can be used for detecting the pressure changes within the overlying aquifer prior to any CO_2 leakage, i.e. in an early-warning fashion, as the reservoir brine, pushed by the injected CO_2, will flow through the leak and create a potentially detectable overpressure (i.e. pressure difference between the observed one and the initial one prior to the CO_2 injection). The detection is "likely" to be detected over a pressure change of 0.1 bar according to Chabora & Benson (2009).

This supposes that the leak reaches an aquifer used for pressure monitoring and that it happens close enough to these transducers. The seismic-based technique has a broader scope: it may detect an accumulation in any of the overlying aquifers and the surveyed area may not be technically limited. But it can only detect the anomaly after the gaseous plume has actually accumulated within the overlying aquifer, as depicted in Figure 1. Under conditions similar as those observed at Sleipner or Weyburn, accumulations of 1000 to 10000 tons of gaseous CO_2 could be detected at a depth of 1 km (Benson, 2006). In the present article, we focus on this late detection scenario of the secondary accumulation, considered to be the less favorable case.

2.2. Leak characterization and localization

The second stage of risk management is to gain knowledge on the nature and size of the "anomaly" in order to precisely assess the risk and to balance and design the corrective options. Pressure monitoring can detect the anomaly faster, but deducing the leak's location is not straightforward.

An approach can rely on the description of the overpressure in the overlying aquifer through either analytical or numerical modeling, and then on the inversion of the monitored pressure signals. The idea was proposed by Javandel et al. (1988), and Zeidouni & Pooladi-Darvish (2010a,b) recently developed a new analytical solution and proposed its inversion in a purpose of localization and leak characterization. One of their conclusions is that locating a leak using one single pressure signal is very unlikely. The analytical models suppose a homogeneous and horizontal aquifer, and the pressure solution depends on the leak characteristics (i.e. permeability, section area, and location) and on the aquifer hydraulic properties (transmissivity, storativity, etc.). They show that using several pressure monitoring wells is required and that increasing the number of monitored signals and the recording duration largely decreases the uncertainty of the leak characterization.

Both authors considered this hydraulic leak characterization as a part of a storage site selection process and not as a monitoring technique. They therefore do not focus their study on the time delay necessary for locating a leakage happening during storage operations. Zeidouni & Pooladi-Darvish (2010a,b) consider a 100 days injection and monitoring period, whereas Javandel (1988) presents recorded signals from 1 month to 1 year. We assume that the same order of magnitude -a few months- is necessary for characterizing an unexpected leak during a storage operation. This duration also depend on the number and quality of recorded signals, and on the acceptable uncertainty threshold (Zeidouni & Pooladi-Darvish, 2010b).

In the case of detection of the secondary accumulation, seismic monitoring, though expensive and deployed less frequently than pressure monitoring (deployed in a quasi-real-time manner), can provide accurate information for risk management, like the accumulation location, shape and size. The time delay associated with this detection is a function of the frequency of the surveys and on the time required for processing the data. The seismic monitoring surveys conducted at Sleipner in 1994, 2001, 2004 and 2006 have for instance enabled the identification of the supercritical CO_2 plume as a multi-tier feature comprising a number of CO_2 layers, each up to a few meters thick (Chadwick et al., 2009). This example shows the accuracy of this monitoring technique under favorable conditions.

2.3. Categories of leaks and possible corrective actions

The third stage of risk management consists in deploying a corrective measure, or a set of measures, aiming at minimizing the anomaly and restoring the system. The choice of the appropriate measure strongly depends on the nature of the leak, which may be classified as either man-made or natural.

The first category corresponds to wells in operation or abandoned ones, hence to a complex engineered structure, from which CO_2 might leak through various flaws (Gasda et al., 2004): via altered material (e.g. through the steel casing as a result of corrosion, through the cement sheath or the cement plug due to either degradation or fracturing) or along interfaces (e.g. rock formation/cement fill, cement fill/steel casing, or cement well plug/steel casing). Various intervention strategies are already available and have been tested, usually by the hydrocarbons industry (Marca, 1990; Merritt et al., 2002; IEA-GHG, 2007b). In case of detected flaws, standard techniques exist for repairing (e.g. wellhead repair, squeeze cementing, or patching casing) or replacing defective well elements, or for abandoning the well. In case of an uncontrolled well ("blow-out"), protocols exist in order to "kill" the well by injecting dense fluids (Lynch et al., 1985). Major research efforts currently focus on the loss of mechanical integrity of wellbore system in the long term (Berge, 2009).

The second category corresponds to natural pathways and includes potential flaws within the caprock formation, such as natural faults or fractured zones. In contrast to engineered man-made leaks, there is a lack of past experiences in interventions at depth levels considered for CO_2 storage (of the order of >800m depending on pressure and temperature conditions) on such natural systems. A possible strategy is to modify the hydraulic properties either directly within or above the migration pathway through the creation of chemically or microbially-induced barriers. Such a strategy can take advantage of experiences gained by oil and gas activities in applying polymer-gel treatments for reducing channeling in high-pressure gas floods and for reducing water production from gas wells (Raje et al. 1999, Grattoni et al., 2001). Initially such techniques were mainly used for controlling the flow into matrix-rock porous media. Recently, studies have reported successful applications to fractured rock (Cunningham et al., 2009). Another recent concept is based on engineered microbial biofilms using the process of ureolysis for precipitating crystalline calcium carbonate, hence sealing the targeted pathway (Sydansk et al., 2005). But such approaches still represent an area of ongoing research works.

2.4. The hydraulic barrier technique

The previous paragraph shows that in some cases of man-made leaks, and more importantly in most cases of natural ones, modifying the leak hydraulic properties (e.g. porosity and permeability of the fractured zone or of the degraded annular well cement) may be unfeasible. In this article, we analyze an alternative corrective option aiming at countering the driving forces of the leakage based on the creation of a hydraulic barrier (also named “pressure ridge”) in order to counter the hydraulic gradient (i.e. the injection-induced overpressure) that drives the flow up in the leak. The principle relies on the pore pressure increase over the leak through water or brine injection in the overlying aquifer (see Figure 1).

Hydraulic barriers are commonly-used as a preventive or corrective measure in pollution engineering. For instance, production or injection wells can be used for locally modifying the hydrogeology in order to protect the drinking water against salt water intrusion, which is one of the most widespread forms of groundwater pollution in coastal areas (Parrek et al., 2006; US EPA, 1999). Compared to these applications, one major difference is that the technique will have to be deployed much deeper for CO_2 leakage cases (same order as the one of the storage aquifer). This introduces two major potential limitations to its applicability: (1) the overlying aquifer at this depth may present poor properties, potentially preventing the induced pressure from reaching a level sufficient for countering the leakage driving forces; (2) the associated practical difficulties (water management; drilling of deep injection wells; cost). Both of these aspects are discussed in section 4.

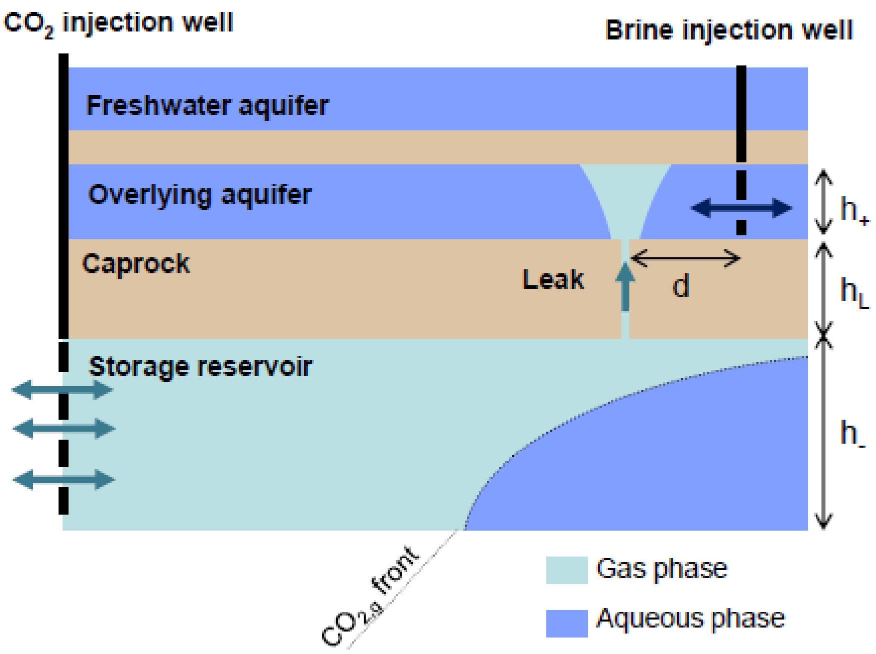

Figure 1: Schematic overview of the generic leakage & hydraulic barrier scenario.

3. CO_2 injection and leakage scenario

3.1. Conceptual model

The proposed intervention plan is investigated considering the following storage scenario: the operator plans to inject 100 $kg.s^{-1}$ of CO_2 (about 3 million tons per year) during 10000 days (about 27 years) through one injection well in a 100 m thick and 1200 m deep saline aquifer. That storage reservoir is connected to a 30 m thick overlying aquifer through a porous column located at a distance of 1 km from the CO_2 injection well. This leak may either represent a leaky well or a permeable fault, and might lead to a major fluid leakage. The defined model is close to the problem 1.1 of a recent benchmark assessing codes performance for CCS modeling (Class et al., 2009). The main differences are that we presently use an 11 times larger CO_2 injection rate (i.e. industrial-scale) and a 120 times larger lateral extension of the aquifer formation. The CO_2 injection is carried out until a secondary accumulation CO_2 can be detected in the overlying aquifer, which happens at 10 years.

3.2. Model set-up and parameters

This conceptual scenario is modeled using the multiphase flow transport simulator TOUGH2 (Pruess et al., 1999) combined with its module ECO2n (Pruess, 2005) accounting for the properties of the brine-CO_2 mixture. A three dimensional grid is constructed, composed of two horizontal and homogeneous 78 × 78 km aquifer layers connected by a vertical conduit (Figure 2). The grid mesh is composed of a central 1 km^2 area of 25 m×25 m grid bocks. Additional refinements using local grid refinement technique (Audigane et al., 2011) are carried out around the wells and around the leak down to a minimum area of 1.6 m × 1.6m. Outside of the central area, the grid cells dimensions follow an exponential progression so that grid cell radius are doubled every three elements up to a distance of 78 km and no grid block has more than two connections per face. The section of the outermost elements is 10 km × 10 km, and the total number of grid blocks is 18000.

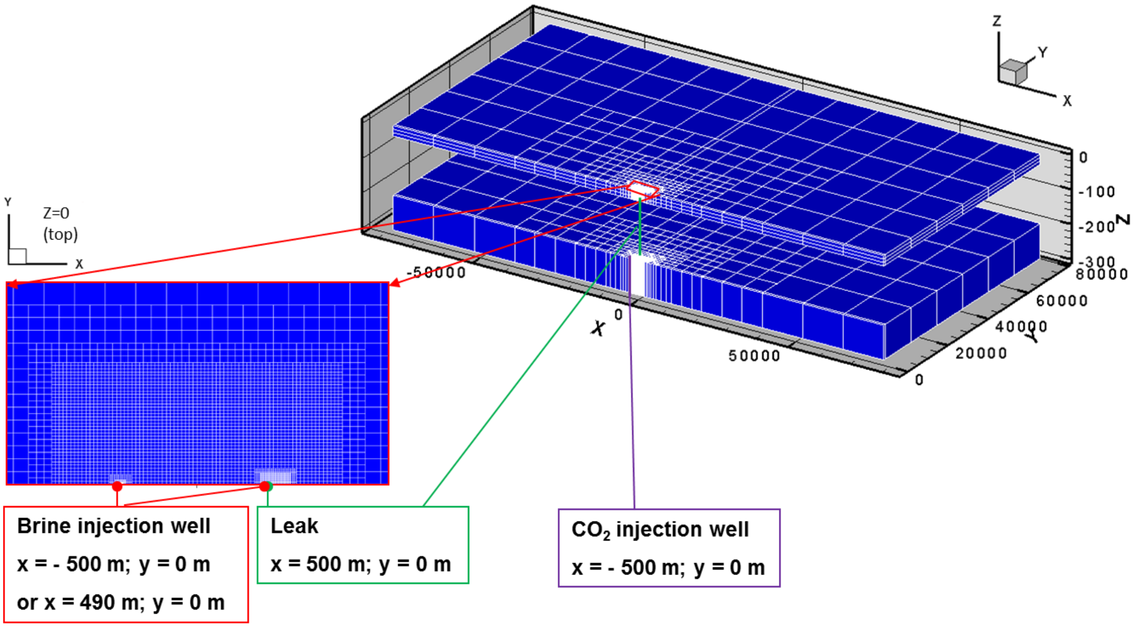

Figure 2: Simplified geologic model and its 3D mesh representation for modeling the leakage through a porous column from a storage reservoir to a shallower aquifer.

Gravity effects are assumed to be negligible in the storage aquifer, which is consequently represented by one 100 m thick layer. Although the actual flow is not purely one-dimensional, we assume that considering the large injection flow rate, viscous forces dominate gravitational forces and the flow can reasonably be approximated as one-dimensional in a first approach. Gravity effects are taken into account in the top aquifer, which is made of three 10 m thick layers, since the gaseous leakage flow is small.

No-flow Neumann boundary conditions are imposed below and above the aquifers as we consider that the fluid flow though the leak dominates other possible migration outside of the aquifers. The vertical surface defined by the CO_2 injection well and the leak is a symmetry plane for the flow.

The parameters used are chosen similar to the ones of the “Problem 2” of Pruess (2005), which can be considered typical of sedimentary formations suitable for CO_2 storage, with high-enough permeability and porosity (Table 1).

Parameter	Value
Porosity	12 %
Permeability (overlying aquifer)	1.28 10^{-13} m^2
Permeability (storage aquifer & leak)	10^{-13} m^2
Initial pressure	120 bar (12 MPa) in the bottom layer & hydrostatic gradient
Temperature	45 °C in the bottom layer and 3°C/100m vertical gradient
Brine salinity	15 % wt (165 $g.L^{-1}$)
van Genuchten m	0.457
van Genuchten P_0	0.2 bar (0.02 MPa)
Residual gas saturation	0.05
Residual brine saturation	0.3
Pore compressibility	4.5 10^{-10} Pa^{-1}
CO_2 injection	100 $kg.s^{-1}$ for 27 years (planned) or 10 years (leakage scenario)

Table 1: Parameters used for the simulations

We also introduce the transmissivity T and the storativity S as standard hydrogeological parameters for the overlying aquifer:

$$T = \frac{k_+ \rho_b g h_+}{\mu_b} \qquad (1)$$

$$S = \rho_b g \omega h_+ (\alpha + \beta) \qquad (2)$$

In these definitions we use the brine density $\rho_b = 1102\ kg.m^{-3}$, viscosity $\mu_b = 8.2\ 10^{-2} Pa.s$ and constant brine compressibility $\beta = 3.5\ 10^{-10} Pa^{-1}$ which are the original values for the brine in the overlying aquifer. We use the values from table 1 for the permeability k_+, the height h_+, the porosity ω and the pore compressibility α. We find $T = 5.0\ 10^{-5}\ m^2 s^{-1}$ and $S = 3.1\ 10^{-5}$. The influence of the transmissivity is discussed in section 4.

3.3. CO_2 leakage and secondary accumulation

During the injection, the CO_2 plume laterally spreads reaching the leak location after about 2.7 years (1000 days) of injection (cf. figures 3&4). At that point the brine leakage is almost totally replaced by the CO_2 leakage, which reaches a value of 0.088 $kg.s^{-1}$ at 10 years (figure 4). The injection is stopped at 10 years, when a 13.8 kton (i.e. 0.04 % of the total amount of injected CO_2) secondary accumulation of CO_2 has formed within the overlying aquifer (see figure 3, right panel). This accumulation, composed of 18 % aqueous and 82% gaseous CO_2, reaches a lateral extent of 125 m after about 7 years of leakage.

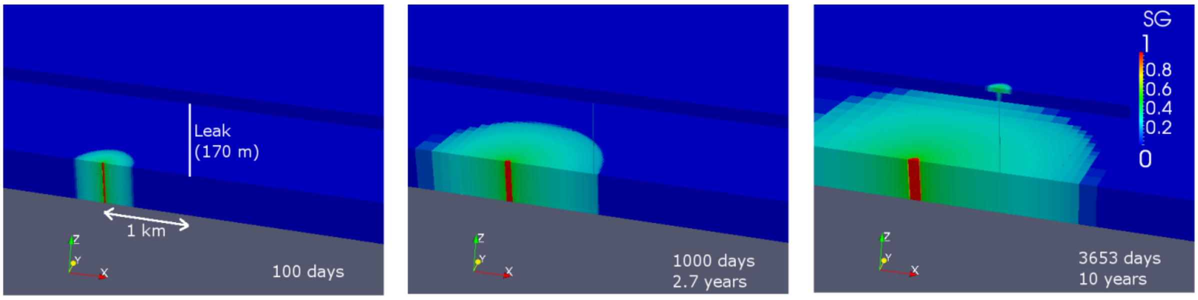

Figure 3: Gas saturation in the 3D model. The CO_2 breakthrough at the leak happens at 2.7 years (middle panel), and the CO_2 injection is stopped at 10 years (right panel).

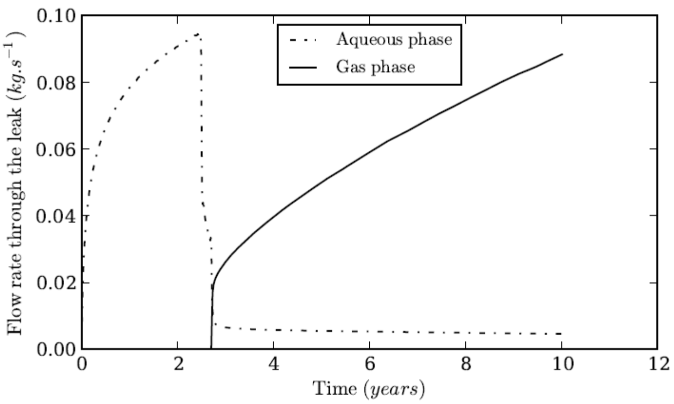

Figure 4: Brine and CO_2 leakage in the top aquifer during the 10 first years. Note the breakthrough of the gaseous phase at the date of 2.7 years.

4. Design of the hydraulic barrier

4.1. Methodology

In order to assess whether the hydraulic barrier is actually feasible or not for a given leakage case, one must have an idea of its main design parameters: what brine injection flow rate should be used and how long the injection should last.

In the following, we note P_{L+} and P_{L-} the pressures at the top and under the leak, and $\Delta P_{L\pm}$ the overpressure at these two locations (considering $\Delta P_{L\pm}(t) = P_{L\pm}(t) - P_{L\pm}(t=0)$).We propose to choose the minimum injection rate Q_0 and injection duration Δt_0 in order to fulfill the following requirements (cf. illustration on figure 5):

- **Efficiency**: the overpressure induced by brine injection over the leak $\Delta P_{L+}(t)$ should be over the threshold $\Delta P_{L+,min}(t)$ in order to prevent the leakage due to the overpressure under the leak and the CO_2 buoyancy (cf. section 4.2);
- **Rapidity**: The duration necessary for stopping the leak should be as short as possible. This duration includes the delay before starting the brine injection (cf. section 4.3) and the lag-time Δt_0, defined as the injection duration necessary for stopping the leakage, i.e. the duration required for the overpressure to reach $\Delta P_{L+,min}(t)$ over the leak. The brine injection may then continue in order to keep the hydraulic barrier effective;
- **Integrity** (mechanical): the induced overpressure remains below the maximum sustainable overpressure ΔP_{max}. This criterion is detailed in the section 4.4.

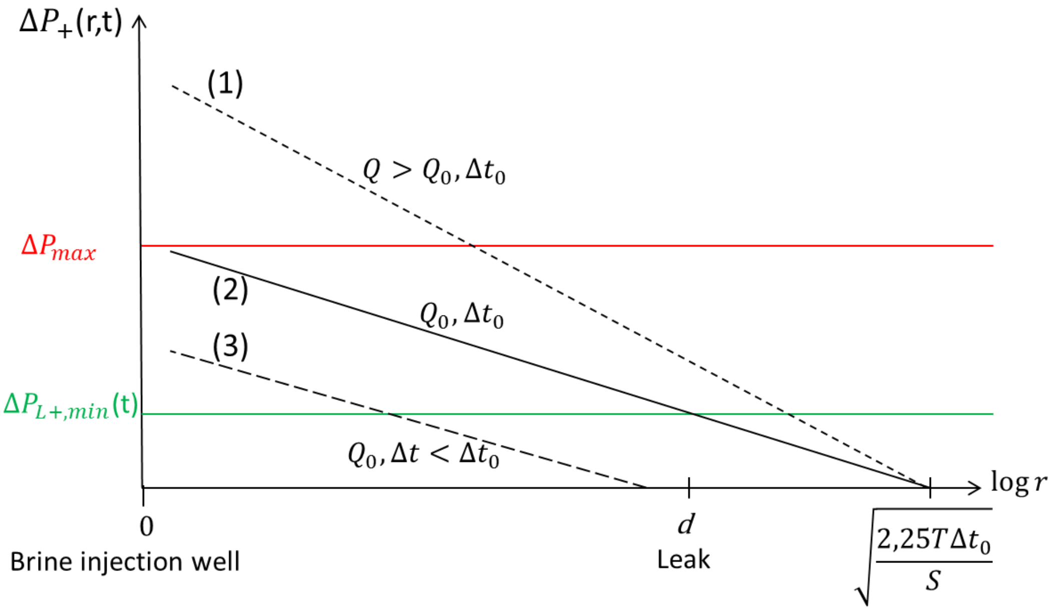

Figure 5: Schematic overview of the linear relationship between the overpressure created by the hydraulic barrier in the top aquifer and the distance to the brine injection well (logarithm scale) – cf. Theis solution, see section 4.2. Three cases are considered; (1) brine is injected during the optimal duration Δt_0, but at a too large rate $Q>Q_0$ so that the overpressure exceeds the integrity threshold ΔP_{max}. (2) brine is injected at the optimal injection rate Q_0 during the optimal time duration Δt_0 so that at the leak position d the overpressure exactly reaches the required threshold $\Delta P_{L+,min}(t)$ (green horizontal line) for stopping the leakage without exceeding the integrity threshold ΔP_{max} (red horizontal line); (3) brine is injected at the optimal rate Q_0, but during a shorter duration $\Delta t < \Delta t_0$. The efficiency criteria is not fulfilled since the overpressure over the leak remains below $\Delta P_{L+,min}(t)$.

The choice of these optimal design parameters $(\Delta t_0, Q_0)$, resp. the minimum injection duration and flow rate, respecting these three criteria is made by following these successive steps:

- The different operational issues are reviewed and the time-delay before being able to start the hydraulic barrier is estimated;
- Considering that time delay, the evolution of the pressure under the leak is computed;
- The necessary overpressure over the leak $\Delta P_{L+,min}(t)$ is deduced from this result and from the assessment of buoyancy;
- The maximum sustainable overpressure in the top aquifer ΔP_{max} is evaluated;

- The optimal tuple $(\Delta t_0, Q_0)$ corresponds to the shortest duration that still ensures that $\Delta P_{L+}(\Delta t_0) = \Delta P_{L+,min}(t)$ and $\Delta P_{L+} < \Delta P_{max}$. This case is represented on the figure 5.

4.2. Efficiency criteria for stopping the leak

We consider the cases where the leak represents a well with degraded annular cements or fractures for which the multiphase version of Darcy's law is applicable. We note ρ_g and ρ_b are the average CO_2 and brine density in the leak. First, we suppose an initial vertical equilibrium in the brine-saturated leak:

$$P_{L+}(t=0) - P_{L-}(t=0) = -\rho_b g h_L \qquad (3)$$

After the leakage occurs, the purpose of the hydraulic barrier implementation is to stop the gaseous CO_2 flow from the storage aquifer to the overlying one, which implies that the pressure above the leak $P_{L+,min}(t)$ respects the following equation:

$$P_{L+,min}(t) - P_{L-}(t) = -\rho_g g h_L \qquad (4)$$

The two previous equations give the minimum overpressure that has to be reached over the leak:

$$\Delta P_{L+,min}(t) = \Delta P_{L-}(t) + (\rho_b - \rho_g) g h_L \qquad (5)$$

This approach, using eq. (5), is conservative since it does not consider the fact that the leakage itself creates a pressure decrease under the leak and pressure increase over the leak, and therefore tends to temper the overpressure driving force. Our numerical examples will confirm that this static approach leads to the right order of magnitude for estimating the time required for stopping the leakage (cf. section 5.1).

A simple approach for numerically estimating $\Delta P_{L-}(t)$ is by means of large-scale reservoir simulations, as presented in section 3 for instance, that will be available for performance assessment of the storage complex during the design of the storage site (as recommended by EC, 2011, the recently published guidance document for the implementation of the European Directive EC, 2009). It also depends on the intervention delay as detailed in section 4.3. The "buoyancy term" can be assessed based on the density difference at the temperature and pressure conditions corresponding to the middle of the leak. For the simulated case presented in section 3, we compute: $(\rho_b - \rho_g) g h_L = 0.6\ MPa$.

The pressure magnitude reached at the leak location due to the brine injection $\Delta P_{L+}(t) = \Delta P_+(r = d, t)$ is given by the analytical solution for the transient pressure changes induced by the injection in an infinite, uniform and confined aquifer (known as the Theis solution, see e.g. Bear, 1979). That solution and its logarithm asymptotic formulation are presented in equation (6).

$$\Delta P_+(r,t) = \frac{Q\mu}{4\pi k_+ h_+} E_1\left(\frac{r^2 S}{4Tt}\right) \approx \frac{Q\mu}{4\pi k_+ h_+} ln\left(\frac{2.25Tt}{r^2 S}\right) \qquad (6)$$

Q is the constant brine injection volumetric flow rate, r the distance from the injection point, S and T are the top aquifer storativity and transmissivity and t the time since the beginning of the injection. International System units are used and E_1 is the exponential integral function. At a given time *t*, the function $\Delta P_+(r,t)$ is merely a line in the domain $\{\log(r); \Delta P_+\}$ (see Figure 5).

4.3. Intervention rapidity & operational issues

The hydraulic barrier implies extracting and injecting a potentially large volume of fluid. Therefore, the water management issue should be carefully tackled when designing the hydraulic barrier, similarly to what has been recently proposed for the storage strategies combining CO_2 injection with resident brine extraction for preventing excessive overpressures in the storage aquifer (see e.g. Buscheck et al., 2011). These strategies consider different uses for the extracted brine, including desalinization (Bourcier et al., 2011) or cooling of the CO_2 capture plant (Court et al., 2011). In most of these cases, a remaining part of the extracted flow has to be re-injected anyway, and could therefore be used for creating a hydraulic barrier in case of major irregularity. For instance, Bourcier et al. (2011) consider in their conclusion a 40% recovery reverse osmosis treatment plant, which means that 60% of the extracted brine flow at least has to be dealt with at the end of the drinkable water production process. In this article, we consider the conservative situation in which the brine is not extracted from the storage aquifer and does not help by lowering the storage aquifer overpressure that has to be compensated by the hydraulic barrier. The brine is assumed to be produced without influencing the storage reservoir and is therefore not included in the models.

Considering the injection issue in the overlying aquifer, this can be achieved either by drilling a new well at the location of the leak, or by turning an existing monitoring well nearby into a brine injection one. The latter case is expected to have lower costs and delays, but its applicability has to be evaluated for each particular leakage scenario. The distance from the leak is an important parameter since it governs the required injection pressure and thus the risk of fracturing. The internal diameter of the wells (which may range from 2.5 inches - 6 cm - or even less to 9 5/8 inches - 24 cm - in Ketzin) should not be a major issue, as it would only require more powerful surface pumps in order to compensate the higher pressure drop in the well. But a monitoring well that has not been designed for bearing high injection pressures may not be usable since there is a risk of collapse of the casing (e.g. by breaking pipes threads, or bursts in the corroded areas). Moreover, if the quality of the bottom primary cementation is not good enough, there is a risk of upwards flow through the annulus and even of lifting up the whole casing (J.-Y. Hervé, personal communication).

The time delay in case of an additional drilling, from the decision to the operational well, varies depending on several parameters including the depth, the availability of suitable drilling rigs and the delay for ordering and receiving the tubing. For instance, in the Paris basin, the delay for drilling a new classical geothermal energy well (1700 m deep; 9 5/8 inches production casing) is at least 6 months, as the delay before having a rig able to reach a depth of one kilometer (there are only 4 in France) and passing the order for the tubing may require at least 4 to 6 months. In case of emergency workover operations on such wells, which do not require new tubing, the typical delay is one or two months (E. Lasne, personal communication). This does not prejudge of what can be done in case of extreme emergency, and delays might be significantly shorter in regions experiencing an important oil & gas production activity due to the local presence of numerous rigs and suppliers. Permitting for the new wells is an additional cause of delay, which might be shortened by including the possibility of a hydraulic barrier as early as possible. It may, for instance, be presented as an option during the first storage permit submitted to the regulators and planned as soon as a first sign of leakage appears.

We consequently assume that the delay from the stopping of the CO_2 injection to the starting of the brine injection range from null (brine is available, the surface piping and a brine injection well are ready to be used) to one year, a six month delay being the reference case considered in the following.

4.4. Mechanical integrity

The brine injection implies a change in the pore pressure of the overlying aquifer, hence changing the stress state which might lead to fracturing or fault reactivation (see e.g. Rutqvist et al., 2007; Rohmer & Seyedi, 2010). For assessing the top aquifer fracturing tendency, we adopt a preliminary approach based on a simplified poro-elastic model. Please note that for a more complete study, a fully coupled hydro-geomechanical model should be used. Assuming an idealized geometry, i.e. a thin reservoir compared with its extension, enduring a constant and vertical stress, the change in minimum effective stress $\Delta\sigma'_h$ due to the injection-induced pressure change ΔP can be written as follows (Rutqvist et al., 2007):

$$\Delta\sigma'_h = \frac{-\nu}{1-\nu}\Delta P \qquad (3)$$

Where ν is Poisson's ratio generally ranging from 0.2 to 0.3 for sedimentary rocks.

We define the maximum sustainable overpressure as the maximum overpressure that will not lead to the tensile failure of the caprock, which corresponds to a null horizontal effective stress after injection (assuming a null tensile rock strength). Considering an initial pore pressure of 100 bars (10 MPa) and an initial stress state corresponding to the ratio between the horizontal and the vertical total stress of 50 % (i.e. corresponding to an extensional stress regime), the critical overpressure threshold reaches ΔP_{max} = 68 bars (6.8 MPa).

4.5. Application of the methodology to the injection and leakage scenario

Figure 6 illustrates the application of the design methodology for a distance d=1km, considering several transmissivities. Immediately after the end of the CO_2 injection (at 10 years), brine is injected at a flow rate Q_0 during a lag time Δt_0 with respect to the three efficiency, rapidity and integrity design criteria as described in the previous sections.

After the lag time, the leak is stopped and we consider continuing the injection at the same pressure in order to keep the barrier effective. More complex scenarios of brine injection in the top aquifer (e.g. time evolving bottom hole injection pressure) can be considered, but this is beyond the scope of the article and we consider continuing brine injection at the same pressure as we chose to focus on the time necessary for stopping the leakage.

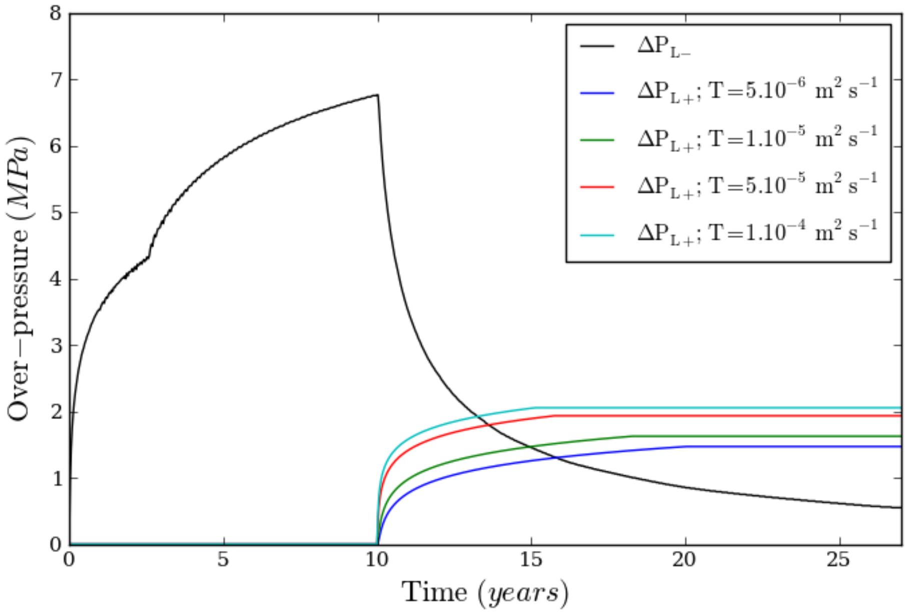

Figure 6: Simulated overpressure under the leak (black line) and analytical overpressures over the leak created by the hydraulic barrier brine injection at d = 1 km without delay (color lines). The CO_2

breakthrough (cusp at 2.7 years) and the effect of stopping the injection (sharp decrease at 10 years) are visible under the leak.

In the following we conduct a sensitivity study in order to evaluate the cases were the hydraulic barrier can be considered in response to this leakage scenario. The influence of three categories of parameters is tested:

(1) the overlying aquifer hydraulic properties so that the transmissivities of the overlying aquifer (Figure 6) range from 5 10^{-6} to 10^{-4} m^2s^{-1}, corresponding to a range of intrinsic permeabilities from 1.3 10^{-14} to 2.6 10^{-13} m^2 according to eq. (1);

(2) the time delay before effectively injecting brine in the overlying aquifer, and after having stopped the CO_2 injection (at 10 years). Two cases are considered: in a first ideal case ("No delay" scenario), a well (e.g. a former monitoring well) is ready to be used for an immediate brine injection in the top aquifer; in a second case, a six month delay is considered e.g. for adapting an existing well or for drilling a new one and building all the necessary surface facilities.

(3) the distance *d* from the leak to the brine injection well varies from 10 m (possibly representing the drilling of a new well) to 1km (possibly representing the case of re-using of an existing well).

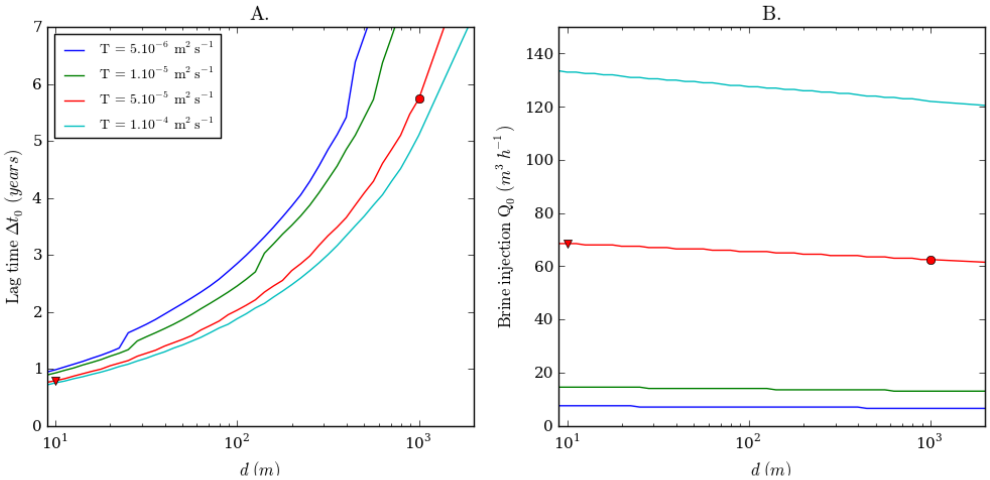

Figure 7: Application of the methodology presented in section 4.5 to the leakage scenario, for the "no-delay" case. The figures presents the optimal tuple (Δt_0, Q_0) (respectively the injection duration Δt_0, or lag time, necessary for stopping the leak on the left panel A.; and the brine injection rate into the top aquifer Q_0, right panel B.) for a range of distance d from the injector to the leak and several top aquifer conditions (transmissivity T varying from 5.10^{-6} to 10^{-4} m^2s^{-1}). The red dot-type marker corresponds to the simulation case considering no delay for the drilling of a well located at d=1km; the red diamond-type marker corresponds to the simulation case considering no delay for the drilling of a well located at d=10m.

The parametric study is presented in figure 7 for the "No delay" scenario, for several transmissivities of the top aquifer and for a range of distances. Two major aspects can be outlined from this sensitivity study:

- The exponential behavior of the lag-time Δt_0 as a function of the distance *d* makes the hydraulic barrier hardly feasible far from the leak and appears as an important limitation to the possibility of reusing a former injection well. The well should be in the vicinity of the leak in order to minimize the duration of the intervention;

- The higher the transmissivity of overlying aquifer, the shorter the lag-time. The necessary lag-time for an overlying aquifer of $T = 5\ 10^{-6} m^2\ s^{-1}$ is in average 1.7 times larger than the one required for an overlying aquifer with $T = 5\ 10^{-5} m^2\ s^{-1}$; but injecting in the latter formations implies largely increasing the injection rate. The injection rate Q_0 for an overlying aquifer of $T = 5\ 10^{-5} m^2\ s^{-1}$ is about 9.6 times larger the one required for an overlying aquifer of $T = 5\ 10^{-6} m^2\ s^{-1}$. Besides, if such high transmissivity formations were present, it is likely that they would have been selected as good candidate formation for CO_2 storage.

Regarding the "6 months delay" scenario, the injection time duration required for stopping the leak is lower than the "No delay", since the pressure under the leak has already reached a lower magnitude.

5. Deployment of the corrective measure

Based on the previous analysis, we simulate three cases using the numerical model described in section 3: brine injection well located at d=10 m away from the leak, with and without delay, and d=1 km without delay. The optimal design parameters (Q_0; Δt_0) are calculated based on the design methodology and listed in the table 2 (it corresponds to the red dots on figure 7). We assume that due to the low compressibility of water, the constant mass flow corresponds to an almost constant volumetric flow Q_0.

Case	Parameters set using the design methodology		Associated mass flow used for the 3D numerical simulation		Effective brine injection duration Δt_0^{eff} for stopping the leakage observed in the 3D simulations	
	Q_0	Δt_0	Q_{NaCl}	Q_{H2O}	Δt_0^{eff}	$(\Delta t_0^{eff} - \Delta t_0)/\Delta t_0$
	m^3/h	years	$kg.s^{-1}$	$kg.s^{-1}$	years	%
Well at 1 km, no delay	62.5	5.7	2.9	16.2	5.6	-3
Well at 10 m , no delay	68.5	0.8 (289 days)	3.1	17.8	0.8 (287 days)	-1
Well at 10 m, 6 months delay	71.5	0.3 (125 days)	3.3	18.6	0.3 (105 days)	-16

Table 2 : Hydraulic barrier design parameters used for the 3D simulations and effective duration for stopping the leakage. The conversion between the volumetric and mass flow rates is made for a brine density $\rho = 1102\ kg.m^{-3}$ and a salinity Xs = 0.15. The first two cases are respectively outlined in Figure 7 by red dot-type and diamond-type markers.

5.1. Time evolution of the pressure in the leak

Figure 8 illustrates the evolution of the pressure profile in the leak for the case of the hydraulic barrier deployed at 1 km without delay. The pressure variation with depth in the leak is initially a hydrostatic profile corresponding to the column filled with brine (solid line). At 10 years (dash line), at the end of the CO_2 storage, the pressure under the leak ΔP_{L-} reaches its maximum. The pressure over the leak ΔP_{L+} has also increased due to the leakage flow entering into the overlying aquifer. At that point, the leakage is maximal and the slope has highly decreased (dash line compared to the solid one) due to the dynamic Darcy flow. After the hydraulic barrier implementation and the brine injection during Δt_0=5.7 years (dash-dot line), the pressure over the leak is increased by the barrier, and the one under the leak is decreased by the natural relaxation after having stopped the CO_2 injection. The flow through the leak has been reduced to negligible and the pressure profile is static again. The gradient is higher than the one of the initial hydrostatic profile (slope of the dash-dot line compared to the solid one) since the column is now filled with a mix of brine and CO_2, which is less dense than the original brine.

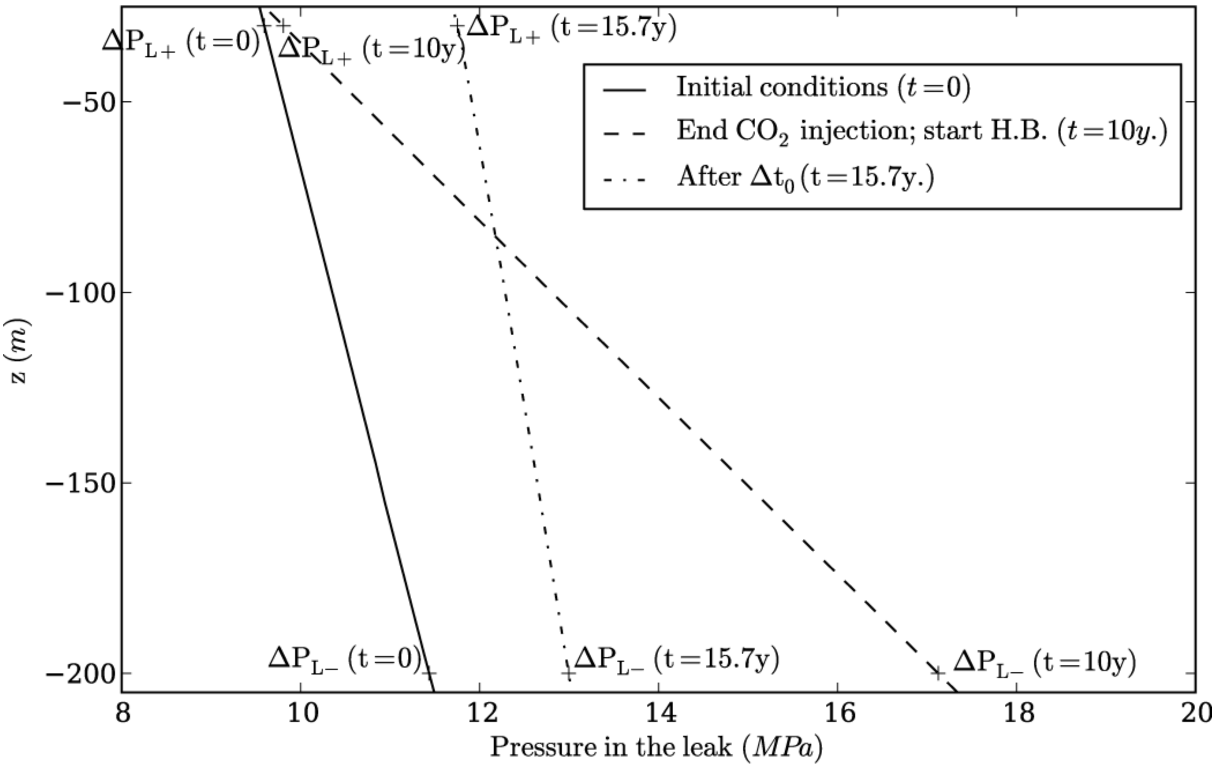

Figure 8: Vertical pressure profile in the leak at various times for the 1 km hydraulic barrier case. The pressures under (ΔP_{L-}) and over the leak (ΔP_{L+}) correspond to the values at respectively -200 m and -30 m. The solid line represents the initial hydrostatic profile in the brine-filled column. At t=10y (dash line), CO_2 injection is stopped and ΔP_{L-} and ΔP_{L+} have increased due to respectively the CO_2 storage and the leakage. At t = 15.7 years, brine has been injected during Δt_0 in order to increase ΔP_{L+} and to stop the leakage. The pressure profile is therefore hydrostatic for a column of mixed brine and CO_2.

5.2. Temporal and spatial evolution of the secondary accumulation during brine injection

When injecting 1 km away from the leak, the accumulation is pushed laterally by the injected brine. The accumulation was initially within a 250 m diameter horizontal circle, and is spread in a 300 m large and 440 m long elliptic shape after 3.5 years. During that time, the maximum gas saturation has decreased from 0.38 to 0.27 (figure 9).

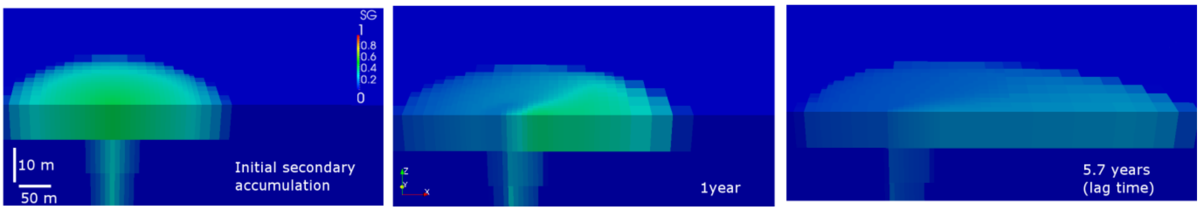

Figure 9: Gas saturation around the leak in the top aquifer during the application of the hydraulic barrier. Brine is injected in a well located 1 km away from the leak, on the left direction.

If we consider the case where brine can be injected 10 meters away from the leak (in the middle of the CO_2 accumulation) after a 6 months delay, the pressure quickly increases enough for stopping the leakage and the secondary accumulation is pushed in a ring shape (figure 10).

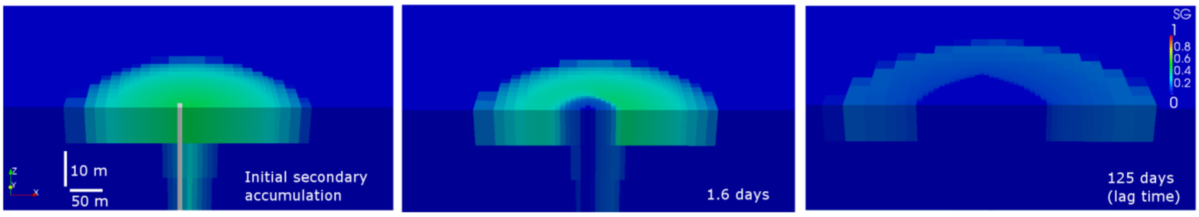

Figure 10: Gas saturation around the leak in the top aquifer during the application of the hydraulic barrier. Brine is injected in the well colored in white in the left panel after a 6 months delay.

5.3. Time evolution of the leakage rate

Figure 11 shows that the temporal evolution of the leakage rate, which increases during the injection phase, reaching a maximum value of ~0.088 $kg.s^{-1}$. When the injection is stopped at 10 years, it steeply decreases during the first years if no corrective measure is implemented, reaching about half the maximum value after 2 years (instant time of 12 years), and then it decays more slowly, reaching an asymptotical value of less than 0.02 $kg.s^{-1}$. The latter behavior is explained by the buoyancy effect: during the leakage, the vertical conduit is filled with a mixture of gaseous CO_2 and brine, which is less dense than the original resident fluid (brine only). This implies that even if the pore pressure decreases to its initial hydrostatic values, the leakage will continue as long as there is mobile $CO_{2,g}$ under the leak and in the column.

In comparison, the hydraulic barrier rapidly decreases the leakage, which is stopped in a time delay of the order of a half a year when the brine injection well is in the vicinity of the leak (d = 10 m cases), and in a time delay of the order of 5 years for the larger well–to-leak distance cases (d = 1 km).

The effect of locating the brine injection in the vicinity of the leakage is therefore of primary interest from a risk management point of view since it greatly reduces the injection duration necessary for stopping the leakage ("lag-time", cf. section 4.5). Despite the fact that it started 6 months later, the leakage could be stopped more than 6 times faster with a well located 10 m away from the leak instead of 1 km.

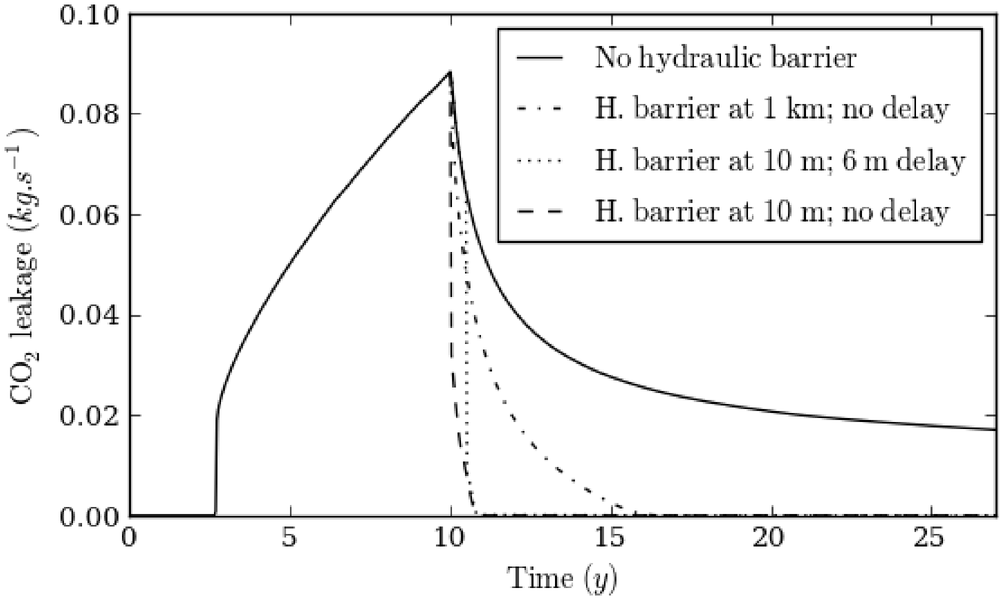

Figure 11: CO_2 leakage flow rate in the top aquifer during the CO_2 injection into the reservoir (first 10 years) and after stopping the injection (after the date of 10 years) considering four cases: no action (solid line); a hydraulic barrier with brine injector drilled with no delay at 1km away from the leak (dash-dot line); a hydraulic barrier with brine injector drilled with 6 months delay at 10m away from the leak (dotted line); hydraulic barrier with brine injector drilled with no delay at 10m away from the leak (dashed line).

5.4. Enhancement of the trapping

As shown in Figure 10, the secondary accumulation in the top aquifer is pushed in a ring shape and swept through the brine injection. Such a sweep effect can lead to the enhancement of the trapping (both residual and dissolution) similarly to the corrective measure considered for enhancing the trapping of the CO_2 plume in the storage aquifer (Manceau et al. 2011). Regarding dissolution, figure 12 shows that the total amount of accumulated CO_2 can be dissolved in a couple of years for the cases considering a brine injector in the vicinity of the leak, whereas the sweep by an injection through a distant well is less effective and therefore requires more time for trapping the CO_2 (cf. dash-dot line in Figure 12). Regarding residual trapping, the secondary accumulation leaves a residual saturation equal to the assumed constant value $S_{g,r}$= 0.05 when it is swept. Yet, considering a constant value for $S_{g,r}$ during this process would only be valid if the medium had previously been totally dried out (S_g = 1). However, the medium has reached a lower saturation (S_g = 0.38 maximum) during the leakage and the residual saturation should consequently be lower. Moreover, we did not account for hysteresis phenomena (relative permeability varying accordingly to the history of wetting / drainage of the medium). The use of numerical (Doughty, 2007) or analytical (Manceau & Rohmer, 2011) models accounting for hysteresis phenomena constitutes a future direction of the present work.

The effect of hydraulic barrier on the trapping of the secondary accumulation strongly depends on the sweep efficiency by the brine front, which requires further investigations especially considering the CO_2 – brine interface instabilities depending on viscosity ratio, relative permeability and capillary pressure functions.

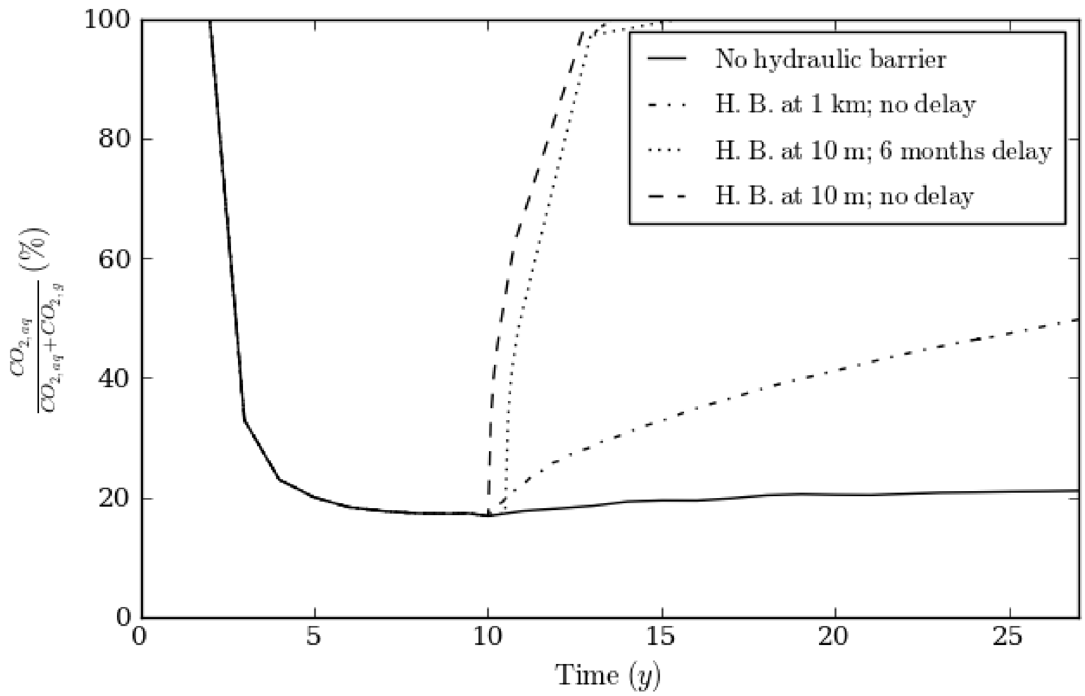

Figure 12: Temporal evolution of the fraction of aqueous CO_2 in the top aquifer during CO_2 injection into the reservoir (during the 10 first years) and after stopping the injection (at 10 years) considering four cases: no action (solid line); a hydraulic barrier with brine injection starting without delay 1km away from the leak (dash-dot line); a hydraulic barrier with brine injection at 10m away from the leak starting immediately (dashed line) or after a 6 months delay (dotted line).

6. Concluding remarks and further works

Implementing a hydraulic barrier requires considering many operational and strategic issues: delays, cost and technical possibility of re-using a former injection well or drilling a new one, availability of the brine, efficiency, mechanical integrity of the overlying aquifer and rapidity of the measure. Most of these issues might hinder the applicability of hydraulic barrier and restrain its design. In this article we discuss these case-specific aspects. In particular, we use the last three criteria for setting the injection flow rate and evaluating the time injection duration necessary for stopping the leakage ("lag-time"). A sensitivity study is also conducted on other parameters: the overlying aquifer hydraulic transmissivity, the delay before action and the leak-to-injector distance.

Two main aspects are highlighted. Implementing a hydraulic barrier in an overlying aquifer with very high transmissivity, though at first sight favorable for injectivity, may not show the expected results, since it requires injecting brine at an impracticably high flow rate in order to reach the overpressure necessary for overcome the CO_2 uprising. Secondly the study identifies the distance from the brine injection well to the leak as the main controlling factor. When brine can be injected in the vicinity of the secondary accumulation, the hydraulic barrier is very effective: the leakage is rapidly stopped (in less than 6 months for the modeled site conditions) and a large part of the accumulated CO_2 is trapped (capillary and dissolution trapping). A hydraulic barrier located even one kilometer away from the injection appears to be much less effective, as it requires 2.7 years for stopping the leakage.

These quantitative results are valid for the considered generic problem and the final design of a hydraulic barrier will be based on site-specific parameters and in-situ conditions, especially considering heterogeneity of the aquifer formations. However, we propose some clear criteria for setting the main parameters of the hydraulic barrier and, then, for having an idea of the effectiveness of the technique This can then be used as an assessment tool for balancing this option with other possible corrective strategies in the case of a leakage.

Further work may consider using hysteresis models in order to better assess the gaseous residual trapping, which depends on history-dependent phenomena. The scope of the study can also be extended in at least two directions: (1) to other corrective measures and (2) to the uncertainty and safety margin in designing this corrective measure.

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