Managing the risk of CO2 leakage from deep saline aquifer reservoirs through the creation of a hydraulic barrier

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Abstract

A prerequisite to the wide deployment of CO_2 geological storage at an industrial scale is demonstrating that potential risks can be efficiently managed, which includes deploying an adequate monitoring during the injection phase and having intervention plans ready in case of major irregularity. This paper considers the injection of CO_2 into a saline formation linked to a shallower aquifer through a leaky pathway. Brine, possibly followed by CO_2, may start migrating up through the leak if sufficient pressure builds-up in the storage reservoir. For some man-made leakages (e.g. abandoned well), and more importantly for most of the natural ones (e.g. faults, fractured zone), acting on the transfer itself (i.e. on the leaky pathway) is hardly feasible. Consequently, the corrective measure hereby investigated aims at countering the main driving force of the CO_2 upwards migration which is the pressure build-up under the leak by injecting brine into the shallower aquifer, thus creating a hydraulic barrier. Results show that this can be an efficient way to stop a leakage in less than a year instead of letting it continue for hundreds of years, even with a low and decreasing flow rate. It may also be implemented as a preventive measure, while continuing storing CO_2.
Keywords: CO_2 geological storage, hydraulic barrier, leakage, risk management, corrective measure

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 or saline aquifers are seen as possible storage reservoirs, the latter offering more opportunities for further industrial development [1]. But a prerequisite to CCS large scale industrial developments is the demonstration by the operators that the containment is effective and the storage is safe [2]. 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 the need to know “what can be done” [3] 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 [4]. It states that the storage permit shall contain the approved corrective measures plan, 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”. Therefore, a proper risk management scheme should also be completed with a site specific risk based interventions plan in order to demonstrate that any undesired consequence can be mitigated.

In case of leakage, different remediation strategies can be deployed, either (1) acting on the root causes of the leakage, such as controlling the pressure build-up [3] or relying on dissolution and residual trapping ([5], [6]) or (2)

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acting on the transfer itself relying for instance on intervention strategies for leaky wells based on the long experience of the oil and gas industry [7]. Nevertheless, for most of the natural leakages (e.g. faults, fractured zone) directly acting on the transfer (i.e. on the leakage pathway) is hardly practicable, as discussed in section 3.

In this regard, the corrective measure investigated in the present paper is based on the “hydraulic barrier” technique aiming at decreasing (or reversing), the pressure gradient in the leak through fluid injection into the top aquifer, thus countering the main driving force of the CO_2 upwards migration for the case of a CO_2 storage aquifer formation connected to an overlying aquifer (possibly used for monitoring) through a leaky pathway that would not have been detected during the site characterization stage (see Figure 1).

The intervention plan is investigated using a three dimensional large scale multiphase fluid flow transport model described in section 2. The leakage and the possible detection techniques and corrective measures are discussed in section 3. The hydraulic barrier itself is discussed in section 4, in a corrective and in a preventive approach.

2. Model set-up and parameters

The proposed intervention plan is investigated considering the following scenario: the operator plans to inject 100 kg/s (about 3 million tones of CO_2 per year) during 10000 days (about 27 years) through one injection well in a saline aquifer. The storage formation is connected to an overlying monitoring aquifer through a porous column, representing a leakage pathway. This leak may represent a poorly plugged well or a localized faulty area. Note that in case of a fully unplugged well, a pipe-flow model should be used [8]. This leaky pathway might lead to a “major fluid leakage”. By “major leakage” we mean that the leak generates a significant pressure build-up in the shallower aquifer, possibly leading to its detection and localization by the monitoring system and that natural flows through the caprock [9] as well as other leakages are assumed to be negligible. This model is close to the problem 1.1 of a recent benchmark assessing code performance for CCS modeling [10]. The main differences are that we presently use an 11 times bigger CO_2 injection rate and a 120 times larger lateral extension.

This conceptual scenario is modeled using a three dimensional grid made of two horizontal and homogeneous 78 by 78 km aquifer layers connected by a pathway conduit (Figure 1). The multiphase flow transport simulator TOUGH2 [11] is used and the properties of the brine - CO_2 mixture is accounted for using the TOUGH2 module ECO2n [12]. The grid mesh is composed of a central 1 km^2 area of 25 m x 25 m grid bocks. Additional refinements using local grid refinement technique [13] are carried out around the wells and around the leak following a logarithmic progression so that the minimum area reaches 1.6 m×1.6m. The leakage pathway has a 6.3 m×6.3m section. Outside of the central area, the grid cells dimensions follow a logarithmic progression so that grid cell radius are doubled every three elements up to a distance of 80 km and no grid block has more than two connections per face.

Gravity effects are assumed to be negligible in the storage aquifer, which is consequently represented by one 100 m thick layer, but are taken into account into the leakage pathway and in top aquifer which are made of three 10m thick layers. No-flow Neumann boundary conditions are imposed below and above the aquifers as we consider that the fluid flow though the leakage pathway 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.

Properties and initial conditions of the bottom layer (storage aquifer) are typical of what may be encountered in saline aquifers at a depth on the order of 1.2 km (table 1). Characteristic curves use the same parameters as those used in the “Problem No.2” exposed in [12] (table 2).

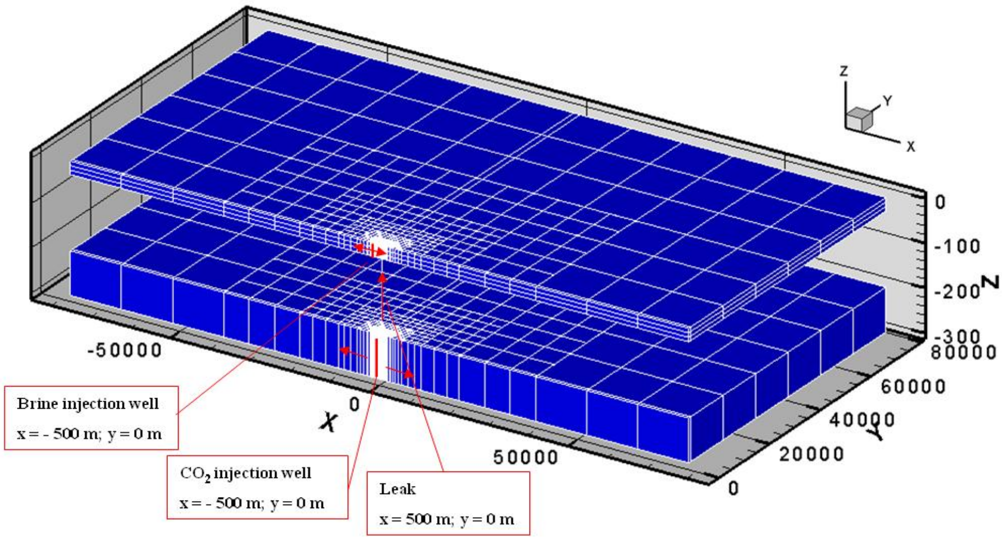

Figure 1: Simplified geologic model and its 3D mesh representation for modeling the leakage through a porous column from a storage reservoir to a shallower aquifer. The reservoir layer is assumed to be located at 1200 m deep.

Table 1: Rocks properties and initial conditions (left) and characteristic curves models and parameters (right. Notations refers to [11])

Porosity	12 %
Permeability	10^{-13} m^2 for the storage aquifer and the leak; 10^{-14} m^2 in the monitoring aquifer
Initial pressure	120 bar in the bottom layer, hydrostatic gradient
Initial temperature	45 °C in the bottom layer; 3°C/100 m gradient
Initial salinity	15 % wt = 165 g.L^{-1}

	Model	Parameters
k_{rl}	van Genuchten - Mualem	$m = 0.457$; $S_{lr} = 0.3$; $S_{ls} = 1$
k_{rg}	Correy	$S_{lr} = 0.3$; $S_{gr} = 0.05$
P_{cap}	van Genuchten	$m = 0.457$; $S_{lr} = 0$; $S_{ls} = 0.999$; $P_0 = 0.2$ bar; $P_{max} = 100$ bar

3. Intervention strategy

3.1. Leakage analysis

Assuming that the leakage pathway has not been detected, the CO_2 injected in the reservoir formation will migrate to the monitoring aquifer through the leakage pathway leading to a secondary accumulation of 32 000 tons of after 27 years (at the end of the CO_2 injection) and 222 000 tons (which is 0.0005% of the total amount of injected CO_2) after a thousand years. This clearly shows that the end of the CO_2 injection is clearly not enough if the goal is to stop the leakage in the long term. In this example, at 1000 years, 87% of the leakage would have occur after the end of the CO_2 injection period (at 27 years) as the leakage continues with a limited decline due to the slow pressure decrease in the storage aquifer [3]. In order to have some order of magnitude of the size of the leakage we consider in this study, we may notice that its maximum (over 10 tons per day) corresponds to one percent of the estimated atmospheric CO_2 emissions on the natural site of Mammoth Mountain (which is estimated around 1200 tons per day [14]).

This CO_2 leakage rate admits no maximum before the end of the 10000 days of CO_2 injection, contrarily to what is observed in the benchmark on the modeling of a leakage through a well [10]. This is coherent with semi-analytical solutions [15] for the infinite and finite boundary cases: the maximum is a consequence of the constant pressure imposed as a boundary condition. In this model, the pressure pulse barely reaches the lateral extent, the aquifer can therefore be considered as infinite.

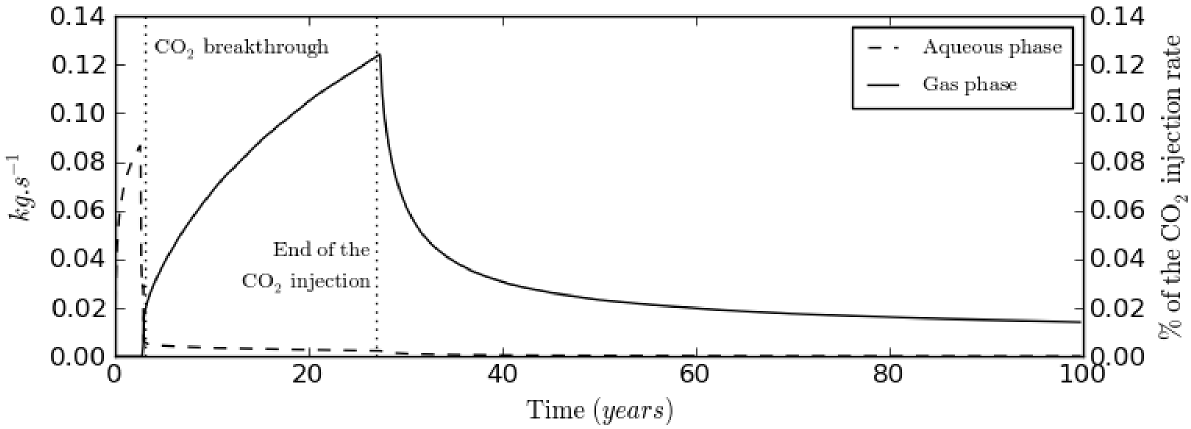

Figure 2: Leakage flow rate through the leak during and after the injection when the injection plan is followed

3.2. Leak detection

In the present situation of a storage aquifer overlaid by a shallower one, seismic and pressure monitoring methods are considered as the best developed [16]. Detection through pressure monitoring may occur prior to any CO_2 leakage, as the brine, pushed by the injected CO_2, will flow through the leak first (cf. figure 2) and create a potentially detectable overpressure in the monitoring aquifer before the gaseous plume reaches the leak. We consider the detection of the leak to be “likely” at an overpressure threshold of 0.1 bar [8].
Seismic monitoring, can detect supercritical CO_2 that has migrated out of the reservoir and become trapped as a secondary accumulation under the overlying layer. 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 [16].

Seismic monitoring would directly locate the gas accumulation, and thus the top of leakage whereas it requires at least several pressure gauges signals and the use of new methodologies based on the comparison of monitored signals with analytical expressions that depend on the relevant distances among other parameters [17]. In the following, we suppose that the leak has been detected and localized. Two situations are considered: (1) it happens after 300 days, which is necessarily made by pressure monitoring as no gas has leaked so far. At that point the overpressure exceeds the 0.1 bar detection threshold in a radius of 2.2 km around the leak. (2) The detection happens after 10 years, as 5300 tons of gaseous CO_2 are trapped in the shallower aquifer and the overpressure exceeds 0.1 bar up to 8.5 km away from the leak.

3.3. Corrective actions

Leakage pathways may be classified as either man-made or natural, leading to very different corrective actions. The first case corresponds to wells in operation or abandoned ones, hence to a complex engineered structure, from which CO_2 might leak through various flaws [18]: via altered material (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 (rock formation/cement fill, cement fill/steel casing, cement well plug/steel casing). Various intervention strategies are already available and have been tested, usually by the hydrocarbons industry ([19], [20], [7]). In case of detected flaws, standard techniques exist to repair (e.g. wellhead repair, squeeze cementing, patching casing) or replace defective well elements, or to abandon the well. In case of uncontrolled well (“blow-out”), protocols exist in order to “kill” the well by injecting weighed fluids [21]. Major research efforts currently focus on the loss of mechanical integrity of wellbore system in the long term [22].

The second case, the natural pathways, includes potential flaws within the caprock formation, natural faults or fractured zones. In contrast to engineered man-made pathways, intervening at depth levels considered for CO_2 storage on such natural systems lacks of past experiences. The main strategy is to create chemically or microbially-induced barriers by changing the hydraulic properties either directly within or above the pathway. It can take advantage of experiences gained in oil and gas activities in applying polymer-gel treatments to reduce channelling in high-pressure gas floods and to reduce water production from gas wells ([23], [24]). Initially such techniques were mainly used for controlling the flow into matrix-rock porous media and recently, studies have reported successful results application to fractured rock [25]. Another recent concept is based on engineered microbial biofilms which are able of precipitating crystalline calcium carbonate using the process of ureolysis, hence sealing the targeted pathway [26]. But such approaches still represent an area of ongoing research works.

However, in some the cases of man-made leakage, and more importantly in most cases of natural leakage pathways, acting on the transfer is hardly feasible. In this article, we propose 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 that drives the flow up in the leak. It is created by increasing the pressure over the leak through water or brine injection in the monitoring aquifer. Hydraulic barriers are a commonly-used preventive or corrective measure in pollution engineering. For instance, production or injection wells can be used to locally modify 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 the coastal areas [26, 27]).

The injection of water or brine in the top aquifer may be created either by drilling a new well at the location of the leak, or by turning an existing monitoring wells nearby into a brine injection well. The latter case is expected to have lower costs and delays, but its applicability has to be evaluated for each particular leakage situation. The distance from the leak is a major parameter to consider, as it governs the required injection pressure and the consequent mechanic risks (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 higher power surface compressors 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 as 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 (personal communication of JY Hervé). We consider here that a well located 1 km away from the leak can be used and that the brine can be produced from the same aquifer or that injecting surface water is temporarily authorized.

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 take 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 (personal communication of E. Lasne). 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). We consequently assume that the delay from the stopping of the CO_2 injection range from an immediate brine injection (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.

4. Hydraulic barrier

4.1. In a corrective approach

In our corrective action case, we consider that the CO_2 injection is stopped when the leak is detected. In the first situation as defined in section 3.2., when injection is stopped at 300 days, the CO_2 never reaches the leak and no CO_2 migrates to the upper aquifer. Consequently, this paragraph will be focused on the 10 years detection situation. At that point there are 6342 tons of CO_2 (gaseous or dissolved) in the shallower aquifer. The pressure barrier is achieved by injecting brine from a well located at a lateral distance of 1 km from the leak (figure 1). The injection operations are carried out until the leakage stops. As depicted in the figure 3, the leakage rate decreases to zero in less than one year. Several scenarios for brine injection flow rate and time delay for setting up the intervention are considered (Table 2). This parametric study shows that both parameters have little influence on the final long term results (1000 years), in all cases the total leakage has been greatly reduced compared to the natural recovery.

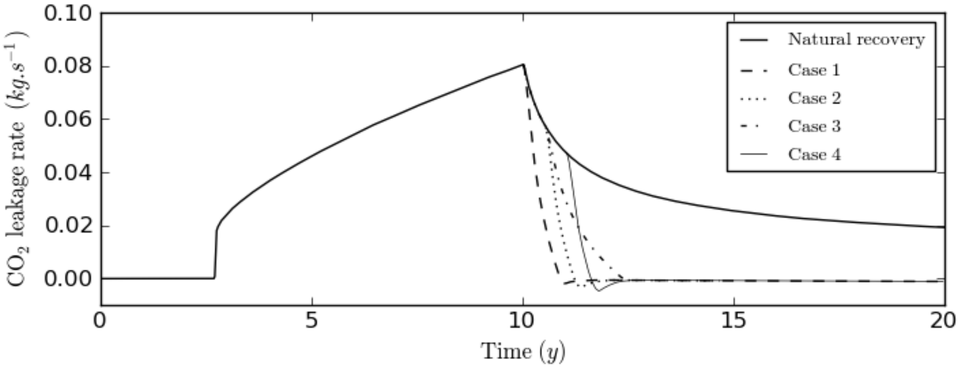

Figure 3: CO_2 leakage rate. The CO_2 injection stops at 10 years and various cases of hydraulic barriers are experienced. Cf. Table 2 for the description of the cases and results.

Table 2: Hydraulic barrier as a corrective action cases and results. CO_2 injection was stopped at 10 years, and at that point there were 6342 tons of CO_2 in the shallower aquifer.

Case	Brine injection design			CO2 in the shallower aquifer after 1000 years	
	Delay (month)	Flow-rate (m3/h)	Duration (month)	in tons	Part having leaked after 10 years
Natural recovery	0	0	0	166250	96%
1	0	30	12	6640	4%
2	6	30	10	7141	11%
3	6	15	18	7359	14%
4	12	30	8	7351	14%

The secondary accumulation of CO_2 represents a potential threat as it might give rise to a high-energy discharge to the surface, a so-called « pneumatic eruption » through pre-existing faulted zones connected to the shallow subsurface or to the surface [9]. A solution is to continue injecting brine in order to displace the plume of gaseous CO_2 and thus to enhance its dissolution and its residual trapping. This is similar to a recently proposed remediation strategy consisting in brine injection through the former CO_2 well for trapping the plume in the storage aquifer [6], excepted that we only target the CO_2 that has leaked in the shallower aquifer and that our model does not account for hysteretic effects. We show in the figure 4 the shape of the plume in a vertical cross-section that includes the brine injection well and the leak, showing the sweep of the plume by the injected brine.

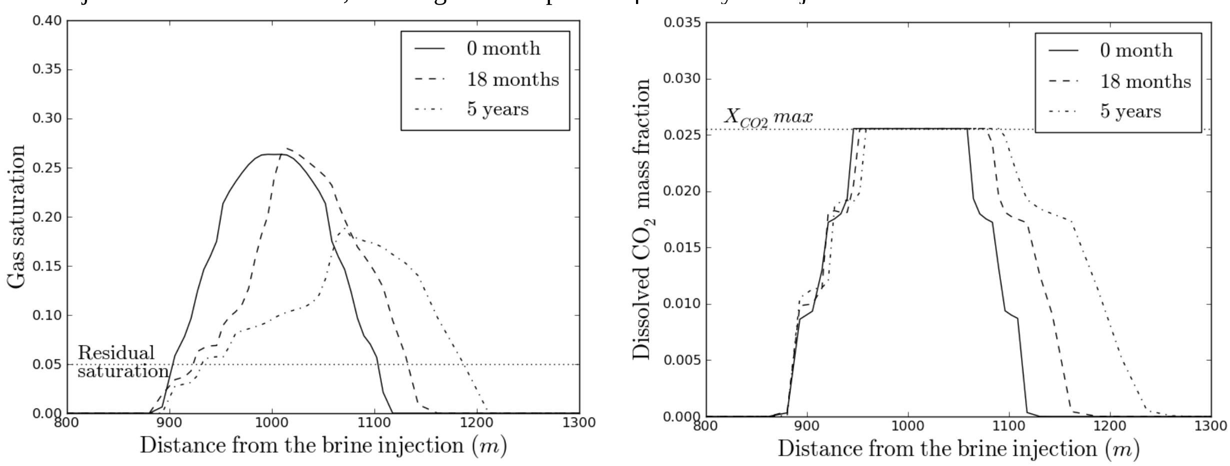

Figure 4: Gas saturation (left) and $CO_{2,aq}$ mass fraction (right) in the upper aquifer (average of the three layers) in a vertical cross-section from the brine injection well (located at 0m) to the leak (locate at 1000 m) after 0, 1.5 and 5 years of brine injection at 15 m^3/h

4.2. In a preventive approach

Let us consider the case in which there are hints of a possible leakage, but investigations can not reduce the uncertainty on its presence (e.g. doubts on the origin of a pressure build-up observed in the shallower aquifer). In that situation, preventive actions may be deployed by setting up a hydraulic barrier while continuing the CO_2 injection as initially planned. The investment made for the whole capture and storage chain can therefore continue being used and the business plan of the operator for valorizing the operation remains almost unchanged.

For designing that preventive barrier, the brine injection has to be chosen in order to create a slightly higher pressure build-up above the leak (obtained by applying standard single phase well functions) than the one created by the CO_2 injection under the leak (estimated based on the numerical simulations of the reservoir carried out before obtaining the injection permit).
In the first situation, the leak is detected at 300 days and a 30 m^3/h (9.1 kg/s) brine injection immediately starts and lasts until the end of the CO_2 injection. As depicted in figure 5, this strategy ensures that the overpressure over the leakage pathway is slightly higher than the overpressure under the leak. Numerical simulations confirm that no CO_2 migrate into the shallower aquifer in that case. The higher overpressure in the top aquifer creates a small brine flow downwards and we observe a low saturation zone under the leak. This prevents the CO_2 upwards migration driven by the buoyancy force after the injection period.
In the second situation, the leakage is detected at 10 years and a 50 m^3/h brine injection starts at that point for 4 years, the injection flow rate being then reduced to 30 m^3/h until the end of the CO_2 injection. In this case, the CO_2 leakage quickly decreases before stopping.

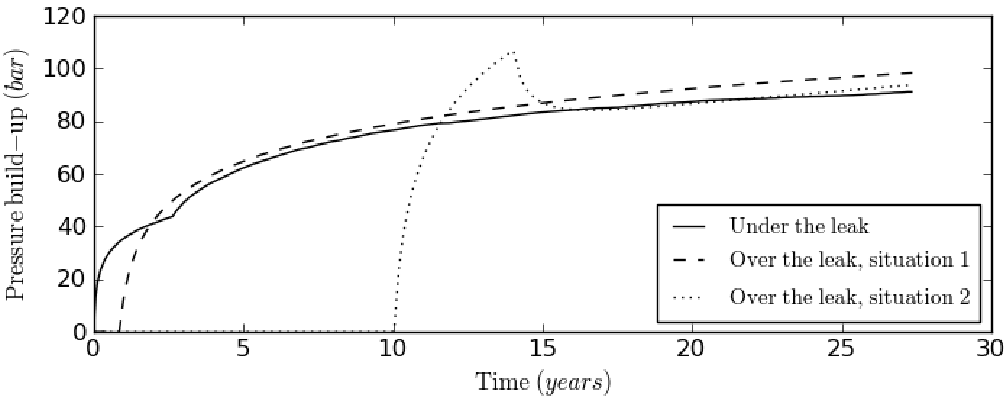

Figure 5: simulated over-pressure under the leak created by the CO_2 injection and analytical pressure build-ups above the leak created by the designed hydraulic barriers. Situation 1: a 30 m^3/h brine injection starts at 300 days. Situation 2: brine is injected at 50 m^3/h from 10 to 14 years, and at 30 m^3/h after.

5. Concluding remarks and further works

In this study we have investigated the applicability of the hydraulic barrier technique for stopping the CO_2 upwards migration through a leak from a storage reservoir to an overlying aquifer, in both corrective and preventive (CO_2 injection continues) approaches. Once the upwards CO_2 migration has began, the simplest corrective action is to stop the CO_2 injection, but it does not stop the leakage which continues for centuries. Compared to that natural recovery case, setting–up a hydraulic barrier stops the leakage in about a year for the simulated generic cases (for various intervention delays and flow rates) and prevents from any posterior leakage. Furthermore, the brine injection displaces the gaseous CO_2 plume accumulated in the shallower aquifer, thus enhancing its trapping through dissolution and capillary processes. These results are valid for the considered case; further parametric studies should be carried out for assessing the influence of site- and leak-specific parameters on the hydraulic barrier design. However, results will have the same order of magnitude and the main point to remember is that the hydraulic barrier can prevent the leakage or stop it in less than a few years instead of letting it continue in the long term, even with a low and declining flow rate. A key issue for a proper implementation of this technique (for its efficiency and for reducing the brine injection and the induced mechanic risks) is the ability of detecting and locating the leak as early as possible. Part of further investigations is to evaluate if this can be achieved by pressure monitoring as it is the first detectable evidence of a leakage.

6. Acknowledgements

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