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(Hydraulic and gas barriers as a corrective measure for undesired CO_2 migration: review and work-plan)

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Public abstract

This report is part of the research project MiReCOL (Mitigation and Remediation of CO2 leakage) funded by the EU FP7 programme[1]. Research activities aim at developing a handbook of corrective measures that can be considered in the event of undesired migration of CO2 in the deep subsurface reservoirs. MiReCOL results support CO2 storage project operators in assessing the value of specific corrective measures if the CO2 in the storage reservoir does not behave as expected. MiReCOL focuses on corrective measures that can be taken while the CO2 is in the deep subsurface. The general scenarios considered in MiReCOL are 1) loss of conformance in the reservoir (undesired migration of CO2 within the reservoir), 2) natural barrier breach (CO2 migration through faults or fractures), and 3) well barrier breach (CO2 migration along the well bore).

This short document summarizes the approach that will be taken to study two methods to prevent CO_2 migration across and above the caprock: 1) the injection of nitrogen; 2) the creation of a hydraulic barrier using water injection in a permeable layer above the caprock.

The principle of nitrogen injection is to increase the interfacial tension between water and gas.

[1] More information on the MiReCOL project can be found at www.mirecol-co2.eu

Since N_2 is lighter than CO_2, the fluid system effective at the base of the caprock will be nitrogen-water, and not CO_2-water. Therefore, higher overpressures are allowed, or from a safety perspective, the safety margin is increased.

The principle of the hydraulic barrier is to inject water continuously in an aquifer above the caprock in order to decrease the pressure gradient across the caprock, or if possible create an inverse pressure gradient. Such measure will decrease the leakage rate occurring across the caprock. This remediation technique can be applied at low cost but is only temporary. The Imperial College Saline Aquifer Model (ICSAM) developed in CO2CARE project has been chosen as the base model to carry out brine injection simulations. Two potential leakage pathways have been envisaged and a number of modeling scenarios have been identified for each leakage pathway.

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1 INTRODUCTION

This report is part of the research project MiReCOL (Mitigation and Remediation of CO_2 leakage) funded by the EU FP7 programme[2]. Research activities aim at developing a handbook of corrective measures that can be considered in the event of undesired migration of CO_2 in the deep subsurface reservoirs. MiReCOL results support CO_2 storage project operators in assessing the value of specific corrective measures if the CO_2 in the storage reservoir does not behave as expected. MiReCOL focuses on corrective measures that can be taken while the CO_2 is in the deep subsurface. The general scenarios considered in MiReCOL are 1) loss of conformance in the reservoir (undesired migration of CO_2 within the reservoir), 2) natural barrier breach (CO_2 migration through faults or fractures), and 3) well barrier breach (CO_2 migration along the well bore).

This short document summarizes the approach that will be taken in work package 7 (WP7) entitled “Hydraulic and gas barriers”, part of sub-project 2 “Leakage through fault of caprocks”. The objectives of WP7 are two folds: 1) test a mitigation technique to prevent CO_2 migration in the caprock using nitrogen injection; 2) test a hydraulic barrier method after CO_2 migration in the caprock using water injection.

The principle of nitrogen injection is to increase the interfacial tension between water and gas. Since N_2 is lighter than CO_2, the fluid system effective at the base of the caprock will be nitrogen-water, and not CO_2-water. Therefore, higher overpressures are allowed, or from a safety perspective, the safety margin is increased.

The principle of the hydraulic barrier is to inject water continuously in an aquifer above the caprock in order to decrease the pressure gradient across the caprock, or if possible create an inverse pressure gradient. Such measure will decrease the leakage rate occurring across the caprock. This remediation technique can be applied at low cost but is only temporary.

[2] More information on the MiReCOL project can be found at www.mirecol-co2.eu.

2 GAS BARRIER

Nitrogen injection within the context of CO_2 storage is used as a mean to secure the injected CO_2, taking advantage of the N_2 interfacial tension properties regarding the cap-rock. By comparison to CO_2, the N_2 interfacial tensions are higher than CO_2 ones, thus allowing higher overpressures to be reached within the storage complex (*Figure 2-1*). The figure is valid for pressures from 1-30Mpa and temperatures between 298-373 °K.

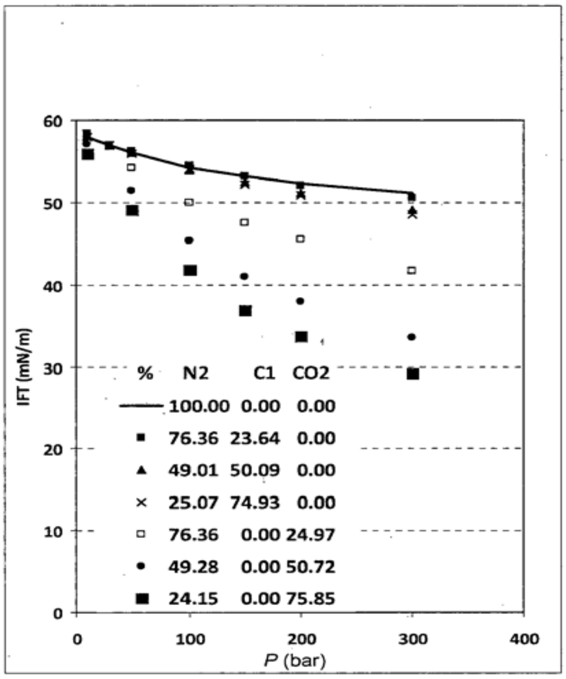

Figure 2-1: Interfacial tension (IFT) comparison (CO_2 - N_2 - C1) - [1]

When considering the full process, several aspects must be known, namely:

- thermodynamic properties of the nitrogen gas,
- injection position and vertical conformance (including gravity effects on the vertical N_2 saturation, regarding reservoir K_v properties),
- areal conformance with regard to the areal extent of the CO_2 “bubble” sought after by design.

There is enough knowledge about the thermodynamic properties of CO_2-N_2 mixture and therefore, we will study only the two last aspects using numerical simulations.

As such, N_2 injection represents one method of CO_2 injection management, aiming at reducing the leaking risk after the injection period, including its long-term fate, if the N_2 treatment spreads over large distances.

2.1 Background and review of the state of the art

2.1.1 Plume extension

N_2 injection is not any different than any gas injection in a reservoir. Consequently, given its specific PVT properties the operational sequence should be:

- determination of the CO_2 bubble extent in-situ, given (a) the allowable overpressure imposed by the cap-rock properties and (b) the rock properties - dynamic and static - of the reservoir.

- choice of the N_2 injection point given the well completion in such a way as to enhance the viscous gradient while minimizing the gravity one, thus as close as possible to the base of the cap-rock.

- injection of a volume of N_2 corresponding to the difference of overpressure allowance for N_2 and overpressure allowance of CO_2. The viscosity of N_2, lower than CO_2 should favor the lateral mobility (K/µ) of the N_2, thus covering the CO_2 bubble.

The entry pressure of a gas in the caprock is given by:

$$Pe = \frac{2\sigma\cos(\theta)}{r} \qquad \text{Equation 2.1}$$

where σ is the water-gas interfacial tension (IFT), θ is the contact angle, and r a pore radius characterizing the porous media. When looking at data concerning the IFT of different gases (N_2, CO_2, CH4), see Figure 2-2 it is clear that N_2 IFT's are higher than CO_2 IFT's. ([2 to 5) - roughly doubling the IFT for the experimental data used. Hence, if the IFT is increasing by a factor of two, the entry pressure will increase accordingly, assuming there is no modification of the contact angle θ. Recent work [12] indicate only a slight modification of the contact angle in the presence of CO_2 (less water wet) and replacing CO_2 by N_2 will be even more favorable (strictly water wet).

Systems	Conditions	IFT (mN/m)
CH_4/water	10–30 MPa, 40–80 °C	48.6–61.7
N_2/water	10–30 MPa, 40–80 °C	53.7–67.2
Medium oil/water	>6.9 MPa, 54.4–81.1 °C	30–35
N-alkane (C_6–C_{16})/water	10–30 MPa, 25-50 °C	49–54
CO_2/water	10–30 MPa, 40–80 °C	16–30

Figure 2-2: IFT for different fluid systems

Concerning injection, the common rule used for the injection of CO_2 is to consider that the maximum reservoir pressure which the reservoir can reach, P_{max} is P_{max} = 1.2/1.3 $P_{res.init.}$. Given the above, it means that the use of N_2 can increase the $P_{max,}$, potentially reaching a value P_{max} = 1.4/1.6 $P_{res.init.}$ available for the N_2/CO_2 system.

At typical reservoir pressure and temperatures N_2 is a gas. The specific PVT properties of N_2 are calculated using an EOS (Peng-Robinson) – density, compressibility while viscosity is calculated using the LBK equation. Here-below we can see a few correlations which can provide some orders of magnitude concerning some of these values – Z-factor and viscosity (*Figure 2-3* and *Figure 2-4*).

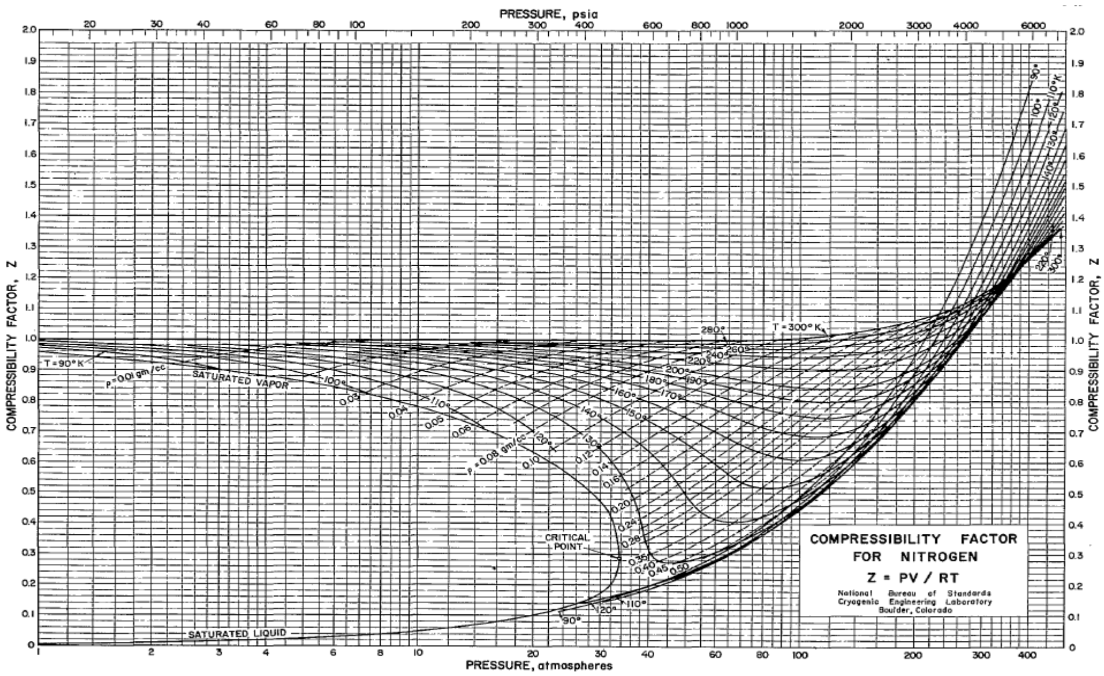

Figure 2-3: Compressibility, Z of N_2 [6]

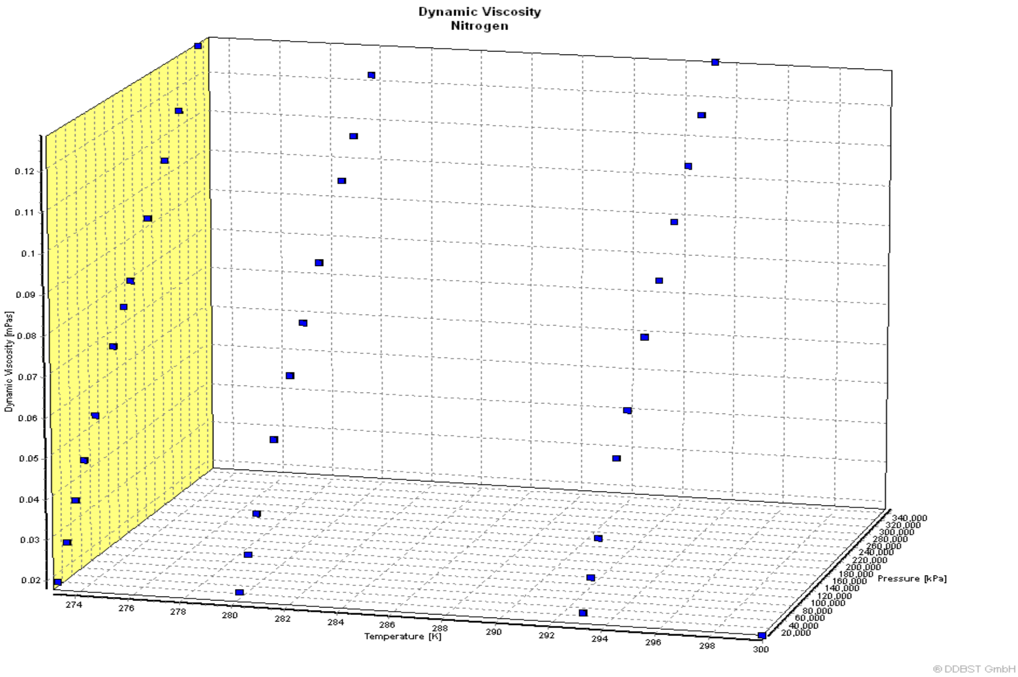

Figure 2-4: N_2 viscosity [7]

Solubility in water will be calculated and input in the form of K-values using [8], see Figure 2-5.

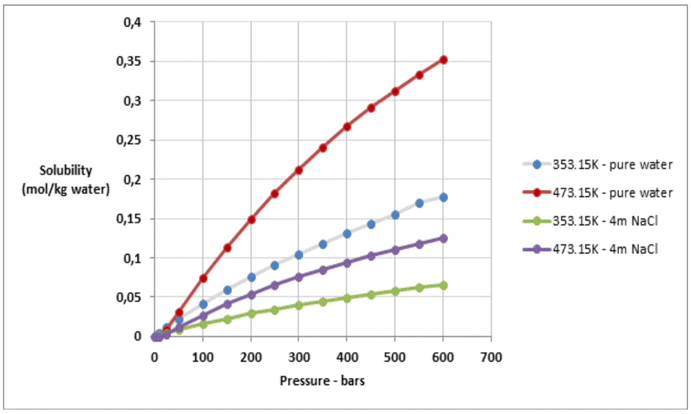

Figure 2-5: Solubility of N_2 in pure water and 4m NaCl [8]

Plume extension

Considerations concerning "reservoir engineering" aspects applicable to the N_2 injection can be easily understood through the use of an analytic model. Instead of developing yet an "other" analytic tool, let's take one commonly applied for CCS [9].

The analytic model assumes radial flow around an injection which penetrates a horizontal aquifer of constant thickness H, porosity φ and permeability k. In this case the location of the interface between the two fluids is a function only of distance from the injection well and time. As a result, the following equation can be written that relates pressures at the top and bottom of the aquifer:

$$p(r,H) = p(r,0) - \rho_{g,w} g h_{g,w}(r) - \rho_g g \left[H - h_{g,w}(r)\right]$$

Where:

p = Pressure
g = Gravitational constant
h_g = Plume thickness
r = distance (radius) from the injection well
and the subscripts (g) and (w) stand for the injected gas and aquifer brine, respectively.

If the density and viscosity of the injected acid gas are considered constant (at values corresponding to the in-situ aquifer pressure and temperature), which can be considered as a fairly reasonable approximation when the pressure decay due to the injection build-up is rapid (errors will be existent only at the near-vicinity of the well), we can write for the fluid flow:

$$Q_{g,w} = -2\pi r h_{g,w}(r) \frac{k k r_{g,w}}{\mu_{g,w}} \frac{\partial p_{g,w}}{\partial r}$$

where (g) and (w) stand for either gas or water and:
k = permeability
$kr_{g,w}$ = relative permeability of either gas or water

$h_{g,w}$ = fluid thickness (or column height) for gas or water at location r
$Q_{g,w}$ = fluid flux through a well of radius r

In the equation above, h_w = H - h_g when $kr_{g,w}$ = 1 since full saturation was assumed for each phase. Also, the total volume must be conserves locally, thus:

$$Q_w + Q_g = Q$$

where Q is the gas injection rate (assumed constant). The change in thickness for either fluid is given by the accumulation of that fluid in the cylindrical volume from the injection well to radius r, according to:

$$\frac{\partial h_{g,w}}{\partial t} = \frac{-1}{2\pi\varphi r}\frac{\partial}{\partial r}\left(rQ_{g,w}\right)$$

where t is time.
The above equations form a system of four equations (three of them differential) with four unknowns: $h_{g,w}$, $Q_{g,w}$ p(r,0) and p(r,H). The solution is based on energy minimization and variational calculus principles. Details of the solutions can be found in the original paper ([9] The fluids in the system will arrange themselves at any time to minimize the amount of energy required to inject the given mass of fluid. In this case energy (work) includes injection, viscous flow (energy dissipation) and buoyancy caused by density differences between the two fluids. In seeking a solution, the following dimensionless variables are introduced:

$$\lambda = \frac{\mu_w}{\mu_g}$$

which is the mobility and:

$$\Gamma = \frac{2\pi\phi\Delta\rho g k k r_w H^2}{\mu_w Q}$$

represents the ratio of buoyant versus viscous and pressure forces, and is an indication of the importance of buoyancy (density differences) in driving the flow of the injected acid gas. This shows that the whole gas injection process (whether CO_2 or N_2) is described by two independent parameters only, the mobility ratio λ and the dimensionless number Γ.

Examination of the latter is very instructive in indicating when buoyancy needs to be taken into account and when it can be neglected. For Γ <0.5 hydrodynamic and viscous forces dominate and buoyancy can be neglected. This situation will happen for:

- high injection rate (strong hydrodynamic force)
- small density difference between the injected gas and formation water (low buoyancy)
- injection into a thin and/or low porosity and permeability aquifer.

At the other end of the spectrum, buoyancy strongly dominates for Γ >10. Such cases will occur for a combination of the following factors:
- large density differences between the injected fluid and formation water,
- injection into a thick aquifer characterized by high porosity and permeability,
- low injection rate (small hydrodynamic force).

In these cases, because of high buoyancy, the plume will, most likely, not reach the bottom of the aquifer. Thus, for 0.5<Γ<10, buoyancy, hydrodynamic and viscous forces are comparably important and the full system of equations described previously has to be solved. The boundaries between the various domains of buoyancy importance and solution applicability (i.e., Γ=0.5 and Γ=10) are not definite, but rather fuzzy. These values are only indicative of the region in the Γ space where the transition from one flow regime to another starts to occur.

In the case of Γ<0.5, when buoyancy is negligible, the profile of the plume (given as a fraction of the total height) of injected gas is given by the equation:

$$\frac{h_g(r,t)}{H} = \frac{1}{\mu_w - \mu_g}\left[\sqrt{\frac{\mu_g \mu_w V(t)}{\pi \phi H r^2}} - \mu_g\right]$$

where: V(t) = Volume of injected gas since inception of injection.
This simplified solution corresponds to the radial Buckley-Leverett solution. For values of Γ> 0.5 solutions are more complicated, necessitating numerical approaches. The Dirac Delta function governs the segregation within the reservoir toward the cap-rock, whereas the above equation governs the plume displacement over the "reservoir" layer where the CO_2 is injected (often considered to be governed by viscous forces alone).

The discussion above is meant to clarify which parameters will govern simulations and therefore the data needs, as well as characterization and overall interaction during simulation.

2.1.2 Pore radius approach

The injection of Nitrogen increases the entry pressure of gas into the caprock. This section describes the underlying physical processes of the interaction with CO_2 that should be considered during application of this technique. The aim is to provide guidelines about applicability of Nitrogen to reduce leakage through a porous caprock.
Here the link to existing geology shall be made. Two kinds of percolation pathways through a caprock exist. Geomechanical failure occurs if the fracture pressure of the caprock is exceeded and fractures open up in the rock. As consequence CO_2 may percolate though the emerging fractures. This mechanical failure provides a constraint to a CO_2 reservoir operation. The maximum reservoir overpressure is related to the hydrostatic pressure. Percolation failure occurs when the entry pressure of the caprock is exceeded and gas percolates into its pore network. In this case N_2 injection can increase the gas entry pressure and therefore can counteract percolation.

The reservoir should be operated such that both failure conditions, geomechanical failure and percolation failure do not occur. Both failure conditions impose constraints to the reservoir pressure do not interact with each other and therefore have both to be fulfilled, independently of the results of the other constraint.

Table 2.1: Critical pore radius for a 76% CO_2 gas mixture and pure N_2. Interfacial tensions are extracted from Figure 2-1.

Depth [m]	Hydrostatic pressure [bar]	Maximum reservoir pressure [bar]	Over-pressure [bar]	Interfacial tension 76% CO2, 24% N2 [mN/m]	Interfacial tension 100% N2 [mN/m]	critical pore diameter 76% CO2 [µm]	critical pore diameter 100% N2 [µm]
500	55	82.5	27.5	44	55	6.4E-02	8.0E-02
1000	110	165	55	36	53	2.6E-02	3.9E-02
1500	165	247.5	82.5	31	52	1.5E-02	2.5E-02
2000	220	330	110	28	51	1.0E-02	1.9E-02

As a practical approach, it is analysed under which conditions both failures can be avoided. N_2 injection can only improve storage security if the pressure is below the geomechanical fracture pressure. The feasible pressure to avoid fracturing of the cap rock is determined. For this pressure it is evaluated whether N_2 injection can increase the storage safety.

Considering a hydrostatic gradient of 11 kPa per m and a geomechanical failure pressure of 1.5 times the hydrostatic pressure, the maximum reservoir pressure is obtained dependent on the reservoir depth (Table 2.1). The interfacial tension between brine and CO2/N2 is a function of depth (Table 2.1). Based on these values it is determined, which is the maximum pore size of the caprock that should not be exceeded. It is shown that the maximum pore size increases by 25% in a depth of 500 m and by 82 % in a depth of 2000 m. This means that the effectivity of N_2 injection increases with reservoir depth. The pore diameter where N_2 injection may increase storage safety is between 10^{-8} and 8 10^{-8}, which corresponds to a caprock facies of tight sandstone or shale (Nelson, 2009). This window for potential nitrogen injection is also shown in Figure 2-6. As further task it shall be determined, which is an appropriate cutoff radius to determine the critical pore radius on the basis of a pore size distribution obtained by experimental methods such Nuclear Magnetic Resonance or mercury injection.

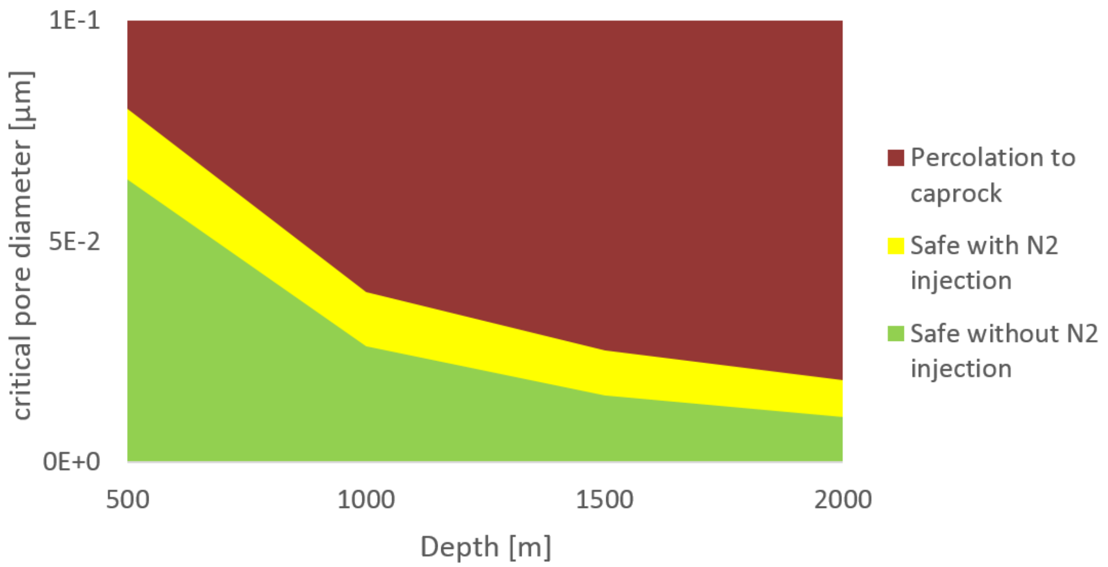

Figure 2-6: Maximum allowable caprock pore size as function of depth. The green area indicates safe CO_2 storage without Nitrogen injection. The safe storage can be extended by the yellow area when applying N_2 injection. For a larger pore radius safe storage cannot be guaranteed. The results are presented for a mechanical cap rock failure of 1.5 times hydrostatic pressure.

2.1.3 Diffusive Mixing

Nitrogen and carbon dioxide are well miscible in all ratios above the critical point of CO_2 (31.1 °C, 73.8 bar), which is typically fulfilled for storage reservoirs. Several processes exist that induce mixing between CO_2 and N_2. This mixing should be avoided since it lowers the N_2 concentration at the caprock and therefore deteriorates the beneficial effect. The mixing is affected by different processes which counteract each other (Table 2.2). The two main effects are molecular diffusion increasing the mixing and gravity segregation causing separation of N_2 and CO_2.

Table 2.2: Processes involved in the mixing between CO_2 and N_2

Process	*Effect on N_2 concentration*
Molecular diffusion	decreasing
Increasing temperature	decreasing
Increasing pressure	stabilizing
Gravity segregation	stabilizing

The physics of the diffusion process is well known and the diffusion coefficients can be derived from existing PVT correlations. The results depends on the boundary conditions and geological configuration. An analytical solution is given below, which is valid for infinite boundary conditions. Effectively this approach is applicable if the thickness of the diffusive layer is smaller than the extent of the different gas components. Figure 2-7 shows the erosion of a formerly sharp concentration gradient with infinite extent boundaries.

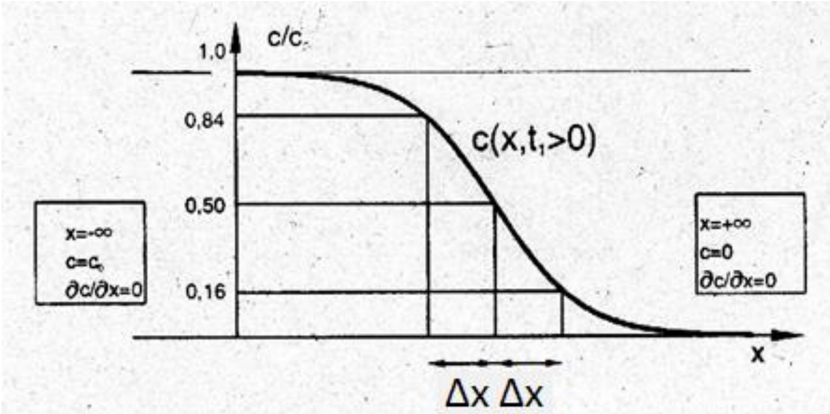

Figure 2-7: Erosion of a formerly sharp concentration front by diffusion.

The corresponding characteristic length Δx from *Figure 2-7* is calculated according to equation 2.

$$\Delta x = \sqrt{2\,D\,t} \tag{2}$$

With Δx as the characteristic distance where the initially pure N_2 phase is mixed with 16% CO_2. Binary diffusion coefficients for a 50% CO_2 and 50% N_2 mixture and geologic conditions are provided in Table 2.3. The resulting characteristic lengths are provided in Table 2.4. For example, if the N_2 layer has a thickness of 3 m, after 1000 days the N_2 concentration caprock will be decreased to 84%.

Table 2.3: Diffusivities for a 50% CO_2/N_2 mixture with respect to different pressure conditions and geothermal temperature.

Depth [m]	Hydrostatic pressure [bar]	Maximum pressure [bar]	Temperature [°C]	Diffusivity hydr. pressure [m²/s]	Diffusivity max. pressure [m²/s]
500	55	82.5	26.5	2.7E-07	1.7E-07
1000	110	165	43	1.3E-07	7.8E-08
1500	165	247.5	59.5	9.3E-08	5.5E-08
2000	220	330	76	7.5E-08	4.5E-08

Table 2.4: Characteristic diffusion lengths for a 1500 m deep reservoir at maximum pressure for different durations.

time [days]	Δx [m]
1	0.1
10	0.3
100	1.0
1000	3.1

The presented approach provides a general idea about necessary scales and times that are required for the application of N_2 as remediation measure. It is simplified, since the lateral extent is assumed as infinite. For a limited layer thickness, concentration levels out faster. Gravity segregation will induce a static vertical concentration gradient and prevent complete mixing. These effects will be further studied in the project (Table 2.2). During the fluid injection phase convective mixing will further contribute to decrease the maximum concentration of N_2. Furthermore, the tortuosity of the pore matrix is not considered. Tortuosity typically decreases diffusion coefficients and therefore reduces mixing of N_2 and CO_2.

2.2 Work program

2.2.1 Plume extension and injection strategy

For the study of N_2 injection, many models are suitable. N_2 injection can be considered both as a preventive and remediation measure. Globally, such measure considers a migration of CO_2 into the caprock but without precise localization, generated by a global weakness of the caprock in terms of entry pressure.

Viewed as a preventive measure, N_2 could be injected before CO_2, with the main objective of producing the largest possible horizontal plume extension below the caprock (Figure 2-6). However, since N_2 injection will also increase the pressure in the reservoir, the overall benefit must be studied carefully and the process optimized. Such optimization will be studied on a synthetic case using analytical formulation or numerical simulation before considering a real case.

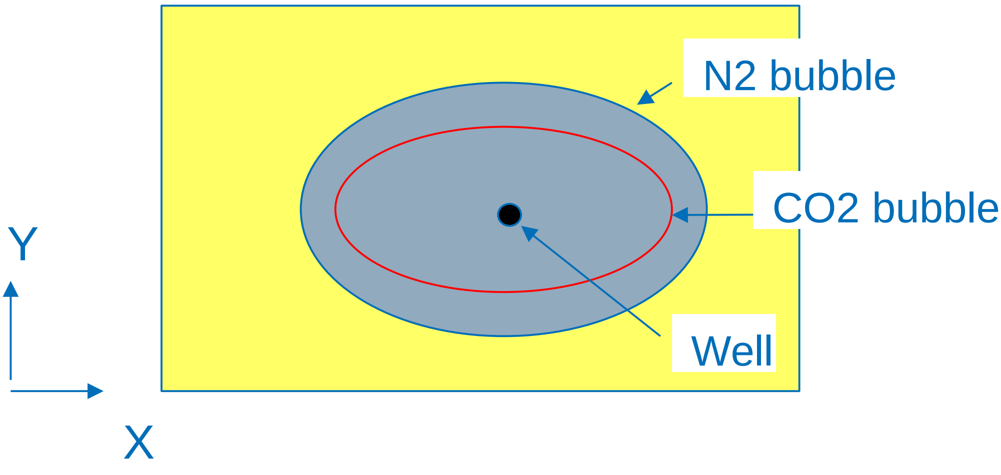

Figure 2-8: Schematic showing the desired effect in terms of areal conformance.

Viewed as a remediation measure, N_2 injection is more complex and its effectiveness must be studied. If one inject N_2 in the presence of CO_2 while it is migrating into the caprock, the resulting increase of pressure may not produce the desired effect, (i.e. limiting the migration). Therefore, it is anticipated that one should most likely, first, back-produce a certain amount of CO_2, and then inject N_2 at an appropriate location in the well.

In order to obtain general conclusions, we will use generic models to study N_2 injection, rather than considering a single situation taken from a detailed geological case. The generic models will be build using a methodology described in appendix 2.4. Shortly, a storage will be described by about 8 non-dimensional numbers representing various physical characteristics of interest for the studied process (aspect ratio, dip angle, mobility ratio, buoyancy, heterogeneity, capillarity, pressure). Then, a data base of existing or potential storage sites will be compiled in order to have typical and extreme values of these non-dimensional numbers. Using an experimental design approach, a sufficient number of generic models will be created to represent the most probable cases; theoretically, with a two level approach and 8 parameters, 2^8=256 cases need to be created and simulated; however, this number may be reduced by eliminating un-necessary parameters. In all these simulations, the N_2 injection will be evaluated based for example on the following criteria:

- over-pressure due to N_2 injection,
- added capacity for CO_2 storage,
- conformance,
- gravity effect and mixing.

Such approach has the advantage of clarifying in which case the N_2 injection is useful.

2.2.2 Mixing modeling

During injection of Nitrogen into a carbon dioxide reservoir both components tend to mix. These mixing processes are affected as well by local geologic parameters and also on the mixing processes that are described in section 2.1.3. The processes are difficult to predict and should be evaluated on the basis of field experiments.
In the pre-injection phase of the Ketzin pilot site 123 m³ of N_2 were injected into the reservoir. This induces a Nitrogen pre-flush of the reservoir during CO_2 injection. In addition to Nitrogen also smaller amounts of Argon, Krypton and Helium are injected as tracer gases.
The experimental conditions mimic a potential scenario for industrial application of the technique. The experiment allows to identify mixing between CO_2 and Nitrogen under reservoir conditions. The relevant mixing processes as described in section 2.1.3 will be identified and a quantification of their importance carried out.
The work will be related to reservoir simulations carried out in WP3 and WP4. A short overview on these simulation is given below, more information can be found in the report for the respective work package.

Numerical Modeling of the Ketzin pilot site
A simple inverse model exists for the Ketzin Pilot site. It integrates three hydraulic tests and the first thirty days of CO_2 injection. The model focuses on the joint inversion of the observed pressure during the hydraulic test, injection pressure in the CO_2 injection well and the arrival time of CO_2 arrival data. It contains 30 free parameters and is feasible to model channeling effects due to layered permeability. It is an advanced continuation of the hydraulic modeling work [13] and a necessary complement to the general Ketzin reservoir modelling work [14].

Modelling approaches that consider only single phase hydraulic tests indicate a region of low permeability between the injection well Ktzi 201 and observation well Ktzi 200. Multiphase simulations of CO_2 injection in contrast indicate a high permeability between both wells. Single phase simulations predict a higher effective permeability than constrained multiphase simulations. The problem is resolved by joint inversion of one single and one multiphase model. It is crucial for this calibration to develop a geological concept that contain the relevant features that allow to reproduce the different type of observations. Generally, the large amounts of data that are recollected from the tests site represent different aspects of the same geological features.
This model shall be used to model the spreading and transport of CO_2 injection experiment at the beginning of the CO_2 injection at the pilot site Ketzin. The model is set up with the simulator Eclipse 300, which allows for modelling multicomponent gas composition including dissolution effects. It will be investigated, whether the flow and transport processes in the reservoir are affected significantly by alteration of interfacial pressure for the gaseous phase containing variable ratios of CO_2 and N_2.

2.3 Summary

The injection of N_2 below the caprock can be used as mean to secure a CO_2 storage. The method is based on the increase of the interfacial tension when N_2 instead of CO_2 is present as the base of a caprock. This process may not be useful in all situations and a large number of generic models will be used to determine in which situations it is useful. A compromise must be found between the over-pressure due to N_2 injection, the added capacity, the conformance and the mixing effect. A specific study will focus on the mixing effect.

2.4 Appendix: Method for generating synthetic reservoir models

Synthetic models will be generated by making use of dimensionless numbers characterizing a CO_2 storage, listed hereafter:

- Effective Aspect ratio (R_L)

$$R_L = \frac{L}{H}\sqrt{\frac{k_z}{k_x}}$$

where: L = reservoir length
H = reservoir height
k_z = vertical permeability
k_x = horizontal permeability
The effective aspect ratio is related to cross-flow within the reservoir. It is a measure of the communication between fluids in the horizontal direction relative to the vertical one. The aspect ratio governs the vertical equilibrium (VE), representing the state of maximum cross-flow, occurring when the forces in the transverse direction is zero. The greater the aspect ratio, the closer it is to vertical equilibrium (well approximated for aspect ratios greater than 10).

- Dip angle group (N_α)

$$N_\alpha = \frac{L}{H}\tan\alpha$$

where: α = dip angle of the reservoir to the horizontal.
Long, thin, dipping reservoirs will have greater values of N_α, lessening the potential impact of gravity overriding, while thicker, shorter reservoirs (low N_α) increase the potential impact of gravity overriding.

- Mobility ratio (M)

$$M_g^w = \frac{k_{rg}^o \mu_w}{k_{rw}^o \mu_g}$$

where: μ_g and μ_w = gas (CO_2 and/or N_2) and water viscosity
K_{rg}^o and K_{rw}^o = relative permeability end-points for gas and water
Mobility relates the ability of gas and water to move relative to each other.

- Buoyancy Number (N_g)

$$N_g = \frac{H\Delta\rho g\cos\alpha}{\Delta P}$$

where: H = reservoir thickness
Δρ = density difference between gas and water
g = gravity constant
α = dip angle
ΔP = pressure difference between the well and reservoir pressure

The buoyancy number is the ratio of the gravity forces resulting of the density difference to the viscous forces in a reservoir. Larger values of N_g indicate larger density differences between fluids and therefore a higher potential for segregation. Thus, the N_g value governs the shape of the CO2 from its injection point (lower N_g values favoring a more cylindrical shape).

- Capillary Number

$$N_{Pc} = \frac{\Delta P}{\sigma}\sqrt{\frac{k}{\phi}}$$

where: σ = Interfacial tension between gas and water
φ = porosity
K = permeability

The capillary number is the ratio of the viscous forces to the capillary ones. It governs the amount of trapping which may occur in an aquifer storage. Capillary forces increase with capillary pressure.
One of the most favorable cases (from the point of view of storage) in case of CO_2 injection is one in which capillary forces dominate over viscous forces and viscous forces in turn dominate over gravitational forces.

- Heterogenity (VDP) – Dykstra-Parsons method
This method is simple, allowing the generation of a vertical (and possibly horizontal) permeability heterogeneity. It is expressed as a variance of the permeability and written as:

$$VDP = \frac{K_{50} - K_{84.1}}{K_{50}}$$

Where K_x is the permeability with a probability of x % .
The significance of such a definition can be seen in the Figure 2-9.

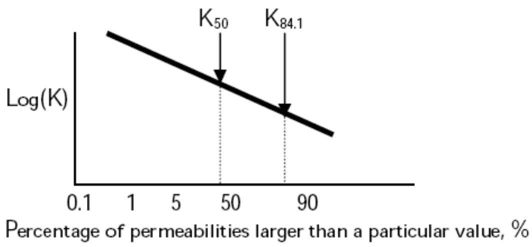

Figure 2-9: Permeability distribution plot.

A homogeneous system has a VDP = 0 and a completely heterogeneous system a VDP = 1. In our case the VDP is given, from which a vertical permeability is generated. This vertical distribution can be generated horizontally (areal distribution). The fact that areal distributions are often more homogeneous than vertical ones is accounted for. Similarly, porosity distributions are adjusted accordingly.
The question may be raised on why geostatistical methods are not used here. The answer is simple. Geostatistical data such as correlation lengths obtained from variogram analysis imply the existence of many wells so as to determine the existence

of such correlations lengths. Furthermore, if correlations can be found at the facies “level”, thus eventually for porosity (for particular deposition environments) it is hardy seen at the permeability level (outcrop studies have proven that). Data base of geostatistical parameters for aquifers or hydrocarbon reservoirs are not easy to come by. By opposition, VDP statistics for many reservoirs have been collected and thus we can use these for our modeling purpose. Given its simplicity, we will use this method in order to introduce heterogeneity in our model.

- Injection pressure

$$P_i = \frac{P_{inj}}{P_{fract}}$$

This ratio determines the dimensionless injection pressure with regard to the fracturing pressure, considered as a limiting pressure for CO_2 operations.

- Residual gas saturation S_{gr}

The above parameters will be collected for a large variety of storage sites, giving a realistic range of values. Then, one can build a simplified reservoir model by choosing a combination of parameters and taking values within the observed range. An experimental design approach will be taken to generate these various situations. In principle, with a 2 level approach and with 8 parameters, 2^8=256 cases need to be constructed. However, not all parameters are relevant for a given process and one can also use a fractional factorial approach, decreasing the number of simulations to be performed to more practical values (e.g. 32).

3 HYDRAULIC BARRIER

Injection of high pressure saline water above a fractured cap rock or a fault, if maintained at a higher pressure than the CO_2 pressure in the reservoir, would not only create an inverse pressure gradient to reverse the flow direction, it would also increase the solubility of CO_2 in the saline water barrier formed, and prevent or at least limit leakage. This procedure could enable fast and reasonably low cost mitigation measures once a leakage is detected, however, this technology can only be used as a temporary measure and allow for more permanent remediation techniques to be prepared and implemented with time.
The efficiency of this technology relies upon continuous injection of brine above the leakage area and a number of site specific reservoir conditions represented by static and dynamic rock and fluid characteristics, geometry and position of the leakage. Furthermore, unless carefully assessed and designed, this methodology may fail to deliver under certain reservoir conditions. Proposed research will involve testing realistic reservoir and CO_2 leakage scenarios representative of selected models from SP5 as described under Task 7.1 and focus on the role of controlling parameters which may affect the success or failure of the hydraulic barrier technology considered.

3.1 Background and review of the state of the art

It was Celia et al. [15] who initially carried out numerical experiments to investigate remediation options near a leaky injection well during CO_2 storage. It was suggested that injection of brine above the caprock, at a higher pressure than the CO_2 pressure in the reservoir, would create an inverse pressure gradient to reverse the flow direction and also increase the solubility of CO_2 in the saline water barrier formed, and thus prevent or limit leakage. Furthermore, coupled with fluid management procedures during aquifer storage (saline water extraction and re-injection above the caprock), this methodology can also be used to minimise displacement and migration of native brine, and avoid pressure build up in closed or semi-closed structures.

In a more recent study, Reveillere et al. [16] conducted a numerical study on the same phenomenon using an overly simple 3D flow model with flat layers (thus buoyancy-driven flow was not accounted for). They reported that this technique may efficiently stop leakage in a relatively short time or may be effectively used as a preventive measure, while continuing injecting CO_2. It is believed that such a procedure could enable fast and relatively low cost mitigation action once a leakage is detected. On the other hand, the results illustrated in the literature are valid for an idealized case and the methodology may have limitations which need to be investigated further through exhaustive analysis of field based properties.

As part of recently completed CO2CARE project, funded by European Commission under the Seventh Framework Programme, a preliminary assessment of the effectiveness of the pressure gradient reversal (PGR) method as a potential remediation technique for CO_2 leakage from deep saline aquifers was investigated using a realistic 3D reservoir/caprock model. A hypothetical CO_2 storage operation involving CO_2 injection at 1 Mt/year for up to 30 years down-dip of a structure high in the model domain was considered. Separate leakage scenario simulations were carried out for 30 different/assumed leakage point sources (18 in the transient zone and 12 in the nontransient zone) independently. At each simulation, the amount of CO_2 leaked out of the target storage reservoir at a selected location was continuously monitored, and the injection terminated once a pre-set detection threshold is exceeded. The brine injection simulation results indicate that the performance of PRG is strongly affected by how early leakage is detected from the start of injection (time-to-detection), which in turns is controlled by the CO_2 leakage detection threshold (in thousands of tonnes), leakage pathway permeability and the distance to the injection well.

3.2 Model requirements and description of the CO_2 mitigation scenarios setup

Model requirements

The basic requirements of the reservoir model(s) are: inclusion of a caprock and the presence of at least one permeable layer in the overburden formations which is suitable for brine/water injection.

Description of the model selected

Guided by these considerations, a review of the currently available reservoir models from the database in SP 5 has been carried out and the Imperial College Saline Aquifer Model (ICSAM) developed in CO2CARE project has been chosen as the base model to carry out brine injection simulations.

The ICSAM model measures 36 km x 10 km and includes several faults (Figure 3-1a). The depth of target storage formation ranges from 1,082 to 3,484 m across the model domain, dipping considerably. The injection well is located at a location where the storage reservoir is between 1,973 to 2,181 m deep (Figure 3-1a). The model has a more or less uniform grid block size of 200 m x 200 m in the lateral direction.

The storage reservoir, which has a thickness of approximately 240 m, consists of 6 layers of varying properties both within each layer and across the layers. The overlying formation (caprock) is considered to be impermeable, except for a 60 m thick layer situated at 180 m above the reservoir, which is assigned a permeability of 10 mD (Figure 3-1b). The reservoir/overburden is initially at hydrostatic pressure, and the reservoir temperature is 92 ^{o}C.

Scenarios

Two leakage pathways are envisaged:

- ✓ Leakage through an areal sink in the caprock
- ✓ Leakage through a fault/fault zone (line sink)

For each leakage pathway, the following key features of the storage reservoir will be considered and implemented to form a number of modelling scenarios

- ✓ Storage reservoir depth (formation pressure and temperature)
- ✓ Top of reservoir topography

- ✓ Caprock thickness/distance to the permeable layer above the storage reservoir
- ✓ Permeable layer permeability/porosity

a)

b)

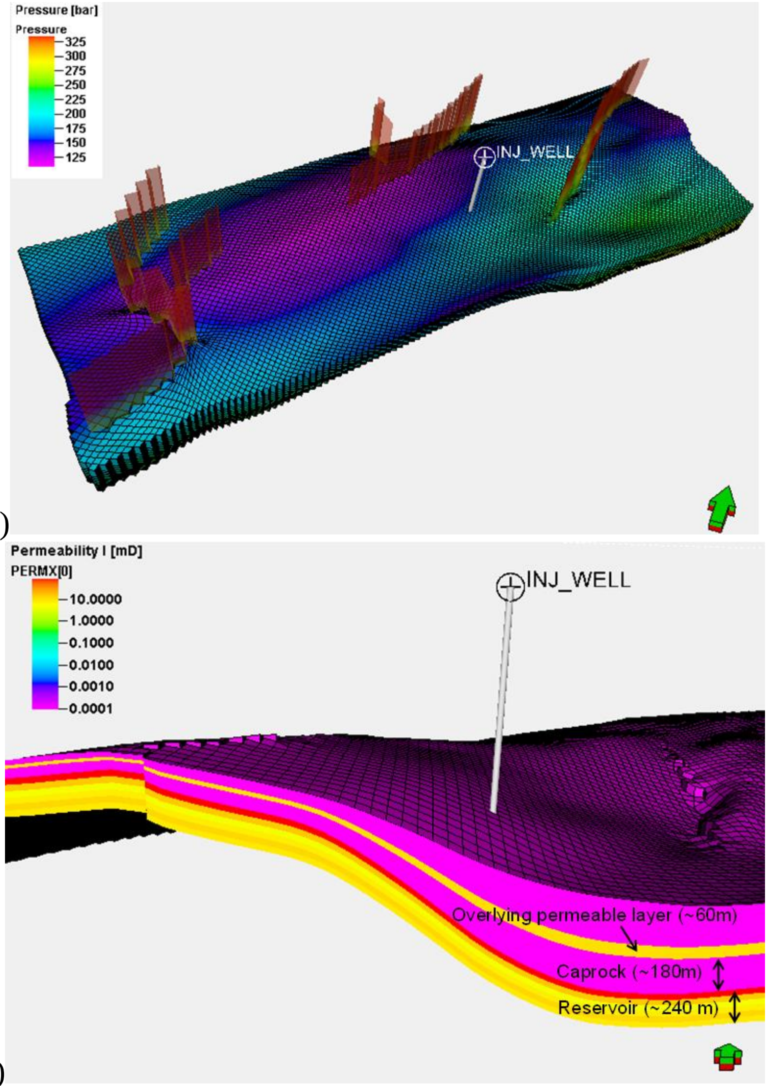

Figure 3-1: Imperial College Saline Aquifer Model (ICSAM). a) Hydrostatic pressure distribution; b) a close-up showing the caprock and overburden layers.

For each scenario the base reservoir model will be modified accordingly for CO_2 and brine injection simulations and associated remediation performance evaluation.

Other elements to be evaluated in terms of their impact on the effectiveness of the remediation technique are

- ✓ Leakage pathway geometry and dimensions
- ✓ Leakage pathway permeability and distance to injection well
- ✓ Leakage detection threshold and amount of CO_2 injected prior to remediation

In leakage scenario simulations, the amount of CO_2 leaked out of the target storage reservoir at a selected location is continuously monitored, and the injection is terminated once a pre-set detection threshold is exceeded. The leakage, however, is allowed to continue until its source (the free CO_2 in the storage reservoir available for leakage) is exhausted to yield the total leakage potential. In this way, potential leakage risk profiles through the leaky caprock/faults may be established to provide a benchmark for evaluating the effectiveness of any remediation measure, including PGR.

3.3 Summary

For hydraulic barriers, guided by the basic requirements of the reservoir model(s): inclusion of a caprock and the presence of at least one permeability layer in the overburden formations which is suitable for brine/water injection, the Imperial College Saline Aquifer Model (ICSAM) developed in CO2CARE project has been chosen from the database in SP 5 as the base model to carry out brine injection simulations. Two potential leakage pathways have been envisaged and a number of modeling scenarios have been identified for each leakage pathway.

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