

Have We Overestimated Saline Aquifer CO₂ Storage Capacities?

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Résumé — Avons-nous surestimé les capacités de stockage de CO₂ des aquifères salins ? —

Au cours d'opérations à grande échelle de stockage géologique de CO₂ dans des aquifères salins, la pression des fluides dans les formations va augmenter, mais devra rester sous des limites définies par des contraintes d'intégrité des sites de stockage. La hausse de pression est la conséquence de deux effets distincts. Premièrement, la pression augmente localement autour des injecteurs de CO₂ pour permettre l'injection du CO₂ dans les nappes. Cet effet peut être contrôlé en ajoutant des injecteurs de CO₂. Deuxièmement, la pression va augmenter à une échelle régionale, soit parce que l'aquifère est fermée, soit parce que le flux d'eau s'échappant de la zone pressurisée ne compense pas volumétriquement le CO₂ injecté. Ce second effet ne peut pas être maîtrisé en augmentant le nombre d'injecteurs.

Dans la première section du papier, nous discutons sur des évaluations mondiales ou régionales de capacités de stockage du CO₂ en aquifère, tant du point de vue de la quantité que de l'efficacité de stockage. Ces capacités sont principalement basées sur une approche volumétrique : la capacité de stockage est la somme des volumes de CO₂ pouvant être stockés par différents processus de piégeage.

Dans la seconde section, nous présentons les efficacités de stockage calculées par une approche en pression, telles qu'établies dans le rapport final du projet CO2STORE (Chadwick A. *et al.* (eds) (2008) *Best Practice for the Storage of CO₂ in Saline Aquifers, Observations and Guidelines from the SACS and CO2STORE Projects*, Keyworth, Nottingham, BGS Occasional Publication No. 14) et explicitées par Van der Meer et Egberts (van der Meer L.G.H., Egberts P.J.P. (2008) *A General Method for Calculating Subsurface CO₂ Storage Capacity*, OTC Paper 19309, presented at the *OTC Conference held in Houston, Texas, USA, 5-8 May*). Une gamme d'efficacités de stockage est présentée, basée sur une revue des ordres de grandeur des compressibilités de pore et de l'eau de formation et des augmentations de pression admissibles. Pour illustrer l'importance de cette approche, elle est appliquée au cas de l'Utsira, dans la Mer du Nord. Dans les sections 3 et 4, les effets pouvant conduire à une augmentation ou une réduction des efficacités de stockage sont discutés. L'extraction d'eau de formation apparaît être une stratégie attractive pour relaxer les surpressions lors de stockage et donc augmenter la capacité de stockage d'un aquifère.

En conséquence des applications numériques effectuées, il est recommandé, lors d'études de screening sur les capacités de stockage de nappes, d'établir la capacité de stockage sur la base d'une formule de compressibilité et de pressurisation plutôt que par une approche volumétrique intégrant différents processus de piégeage local du CO₂. Ceci doit permettre d'éviter une surestimation importante des capacités de stockage. Des études complémentaires sont ensuite nécessaires pour valider les capacités de stockage lors d'une phase de qualification.

Abstract — Have We Overestimated Saline Aquifer CO₂ Storage Capacity? — During future, large scale CO₂ geological storage in saline aquifers, fluid pressure is expected to rise as a consequence of CO₂ injection, but the pressure build up will have to stay below specified values to ensure a safe and long term containment of the CO₂ in the storage site. The pressure build up is the result of two different effects. The first effect is a local overpressure around the injectors, which is due to the high CO₂ velocities around the injectors, and which can be mitigated by adding CO₂ injectors. The second effect is a regional scale pressure build up that will take place if the storage aquifer is closed or if the formation water that flows away from the pressurised area is not large enough to compensate volumetrically the CO₂ injection. This second effect cannot be mitigated by adding additional injectors.

In the first section of this paper, we review some major global and regional assessments of CO₂ storage capacities in deep saline aquifers, in term of mass and storage efficiency. These storage capacities are primarily based on a volumetric approach: storage capacity is the volumetric sum of the CO₂ that can be stored through various trapping mechanisms.

We then discuss in Section 2 storage efficiencies derived from a pressure build up approach, as stated in the CO2STORE final report (Chadwick A. et al. (eds) (2008) *Best Practice for the Storage of CO₂ in Saline Aquifers, Observations and Guidelines from the SACS and CO2STORE Projects*, Keyworth, Nottingham, BGS Occasional Publication No. 14) and detailed by Van der Meer and Egberts (van der Meer L.G.H., Egberts P.J.P. (2008) *A General Method for Calculating Subsurface CO₂ Storage Capacity*, OTC Paper 19309, presented at the OTC Conference held in Houston, Texas, USA, 5-8 May). A quantitative range of such storage efficiency is presented, based on a review of orders of magnitudes of pore and water compressibilities and allowable pressure increase. To illustrate the relevance of this approach, it is applied to the Utsira aquifer in the North Sea. In Sections 3 and 4, we discuss possible effects that may lead to higher or lower CO₂ storage efficiencies. Water production appears to be an attractive strategy in order to address regional scale pressure build up and, consequently, to increase the storage capacity.

Following these quantitative applications, we recommend to evaluate the CO₂ storage capacities of an aquifer, during a screening study for ranking purposes, using a pressure and compressibility formula rather than a volumetric approach, in order to avoid large overestimation of the aquifer storage capacity. Further studies are naturally required to validate the storage capacities at a qualification stage.

List of symbols

C_r, C_w	Rock and water compressibility
g	Gravitational constant, 9.81 m/s ²
h	Aquifer thickness
h_c	Cap rock thickness
k	Aquifer horizontal permeability
k_c	Cap rock average vertical permeability
H	Width (horizontal dimension perpendicular to dip) of the aquifer storage region
E	Storage capacity efficiency, expressed as a pore volume fraction
L	Length (horizontal dimension parallel to dip) of the aquifer storage region
M_{CO_2}	CO ₂ storage capacity
Q_{CO_2}, Q_w	CO ₂ volumetric injection rate and water volumetric production rate in the aquifer
S	Surface area of the aquifer storage region = $L \times H$
V_w	Volume of water in the aquifer
z	Depth
ΔP	Pressure increase in an aquifer as a consequence of CO ₂ storage

μ_{CO_2}, μ_w	CO ₂ and water viscosity
ρ_{CO_2}, ρ_w	CO ₂ and water density
θ	Dip of the aquifer structure

INTRODUCTION

As underlined in the 2005 IPCC Special Report on CO₂ Capture and Storage [3], implementation of CO₂ capture and geological storage at the scale needed to achieve a significant and meaningful reduction in CO₂ emissions requires knowledge of the available CO₂ storage capacity. CO₂ geological storage into deep saline aquifers is presented as an attractive solution due to a large potential CO₂ storage capacity.

CO₂ aquifer storage is distinct from Depleted Gas Reservoir Storage, CO₂-Enhanced Oil Recovery or Enhanced Coal Bed Methane as CO₂ is injected in a geological formation with unaltered pressure conditions. As such no pore space is available for CO₂ from hydrocarbon production (either before or simultaneous to the CO₂ injection operation). Therefore, unless coupled with formation water production, CO₂ aquifer storage will lead to pressure build up both locally (at injectors) and globally (at the basin scale).

Pressure build up may strongly limit the effective storage capacity of a given aquifer because it has to stay below certain limits to preserve the storage site integrity.

The objective of this paper is to underline the fact that the pressure response to CO₂ injection may be the primary effect controlling the CO₂ geological storage capacity of an aquifer. As a consequence, CO₂ geological storage capacity should be derived from a build up approach rather than a volumetric approach. This paper is not reviewing other issues that may adversely impact the CO₂ geological storage capacity, as brine displacement, pressure build up at a large distance from the CO₂ injection area or long term CO₂ migration.

1 REGIONAL AQUIFER STORAGE CAPACITY ASSESSMENTS

1.1 Global Storage Capacity Assessments

Several studies have evaluated geological storage capacities in various basins and various geological storage targets (coal beds, saline aquifers, oil and gas reservoirs).

One milestone report is the 2005 IPCC special report [3] which summarizes some of the previous regional studies concerning CO₂ storage capacity and provides the estimates displayed in Table 1.

TABLE 1

Storage capacity for several geological storage options. The storage capacity includes storage options that are not economical, from [3]

Reservoir type	Lower estimate of storage capacity (GtCO ₂)	Upper estimate of storage capacity (GtCO ₂)
Oil and gas fields	675°	900°
Unminable coal seams (ECBM)	3-15	200
Deep saline formations	1 000	Uncertain, but possibly 10 ⁴

These storage capacity estimates are derived from regional assessments:

- 500 Gt in the USA, with more recent estimates of 160-800 Gt for a single formation, the Mount Simon Sandstone;
- approximately 4000 Gt in the Alberta Basin [4], with 100 Gt from Viking aquifer only;
- 740 Gt in Australia [5];
- 30 to 577 Gt for Europe;
- 1.5 to 80 Gt for Japan.

Sources used in the IPCC report to quantify storage capacity values lack associated uncertainties, but the report indicates that the various methods and data used in these capacity

estimates exhibit a high degree of uncertainty in computing regional or global storage capacity in deep saline formations.

Nevertheless, the values displayed in Table 1 have a major impact as they indicate that aquifers have the largest CO₂ storage capacity compared to other CO₂ geological storage types, and that this capacity is large compared to anthropogenic CO₂ emissions.

The NETL DOE Atlas is an other key reference that was published after the IPCC special report, covering the Western Provinces of Canada and the USA. Capacity values presented in the first version of the DOE Atlas [6] ranges between 919 to 3 378 Gt CO₂ for both USA and Western Canada, with only 60 Gt for Western Canada located in Viking aquifer in Alberta, and up to 200 Gt for Mont Simon Sandstone within three Regional Partnerships (MGSC, MRCSP & SECARB). Version 2 of the NETL Atlas [7] investigated additional formations, leading to significantly larger storage capacities, ranging from 3 300 to 12 620 Gt of CO₂.

1.2 Comparison of Key Regional Storage Capacity Assessments

A look back to the approaches used in these publications provides interesting insights.

A way to calculate CO₂ storage capacity in aquifer is by introducing a volumetric fraction E of the pore volume that will be available to store the CO₂ [6, 7], also called a storage efficiency:

$$M_{\text{CO}_2} = V_w \times E \times \rho_{\text{CO}_2} \quad (1)$$

In Europe, the CO₂ storage capacity was established for selected European countries in the context of two projects: Joule II [8] and GESTCO [9]. The storage potential of some countries was reviewed twice. A low and a high estimate was established for few countries (Germany and Norway).

The 577 Gt of CO₂ estimate is based on summing the highest estimate available for each country.

It turns out that out of the 577 Gt:

- 476 Gt of CO₂ is the high estimate for Norway alone within Joule II project; with an average storage efficiency $E = 5.3\%$ (6% in Chalk and Tertiary aquifers and 2% elsewhere);
 - this high estimate for Norway was discounted to 280 Gt during the later GESTCO project [10], with an average storage efficiency $E = 2.6\%$ for the high estimate (6% in open aquifers and 2% in closed aquifers).
- For Australia [5], a review of relevant sites concluded:
- on a total water pore volumes of 7 000 km³ and a storage capacity of 3 900 Gt assuming CO₂ can replace water in 100% of the pore volume;
 - a restriction of the capacity to 740 Gt of CO₂ after a risk factor weighing;
 - hence a global storage efficiency $E = 740 / 3 900 = 19\%$.

DOE Atlases [6, 7], the calculation methodology is presented in Appendix A and concludes that “*Monte Carlo simulations estimated a range of E between 1 and 4 percent of the bulk volume of saline formations for a 15 to 85% confidence range*”. Hence, the storage efficiency is $E = 1\%$ for the low estimate and $E = 4\%$ for the high estimate (for all basins).

The Alberta basin storage capacity estimate [4] derives from that of the Viking aquifer:

- Viking aquifer storage capacity is around 100 Gt;
- this capacity assumes that formation water can be saturated with CO_2 (dissolving around 53 kg of CO_2 per volume of water) in the area of the aquifer where pressure and temperature are such that CO_2 would be in a dense phase;
- CO_2 density in this area would range between 500 and 700 kg/m^3 , hence, before dissolving it into the formation water, it would occupy between 7 and 11% of the pore volume (E between 7% and 11%).

The extrapolation to the Alberta basin as a whole (4000 Gt) is based on:

- the assumption that Viking aquifer contains 0.88% of the basin pore volume;
- removing 45% of the rock (aquifers and aquicludes);
- removing an additional 40% because of increasing salinity with depth hence decreasing storage capacity.

To summarize, the “upper estimate” of CO_2 geological storage capacity in various basins is calculated assuming it is possible, at basin scale (or large fractions of the basins), to inject CO_2 so that it occupies between 4% and 19% of the pore volume.

1.3 Discussion Related to Aquifer Storage Capacity Assessments

Bradshaw *et al.* [11] underlined the large discrepancies concerning regional capacity assessments between various publications.

Theoretical CO_2 storage capacity is calculated as a cumulative storage from various trapping mechanisms, some of them occurring at a time scale that is not compatible with an industrial project, as sketched in Figure 1.

They proposed to distinguish between theoretical storage capacity; realistic capacity (taking into account a range of geological and engineering cut-off limits) and viable capacity, also considering economic, legal and regulatory barriers to CO_2 geological storage.

Bachu [13] underlined the fact that pressure build up will be significant during the injection phase. Pressure would decay and return to the initial pressure if formation water is flushed away (Fig. 2).

However, no pressure constraint or formula is explicitly presented in order to evaluate the CO_2 storage capacity of an aquifer in order to comply with pressure constraints.

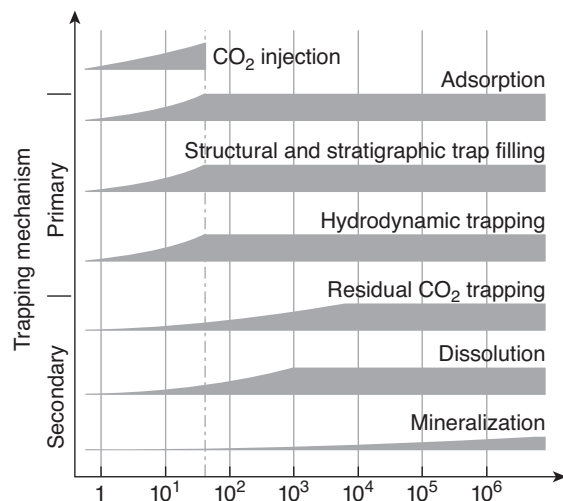


Figure 1

Schematic showing the time evolution of various CO_2 storage mechanisms operating in deep saline formations, during and after injection, from [12].

This range of CO_2 storage efficiencies was confirmed by a parametric reservoir modelling study [14]. It is important to underline that this study did not assess the pressure build up issue as models reviewed CO_2 injection through a single injector into an infinite aquifer. In particular, the pressure interferences between injectors and the set up of an injector pattern were not reviewed in order to derive regional scale CO_2 storage efficiencies.

2 AQUIFER STORAGE CAPACITY BASED ON PRESSURE CONSTRAINTS

2.1 Overview

In the case of a closed aquifer (a volume of water that can not exit the aquifer) basic physics indicate that the storage capacity is limited due to compressibility and pressure build up limitations [1, 2].

In the pressure build up is evenly distributed throughout in a volume of water, the mass of CO_2 that can be stored is directly connected to the pressure build up:

$$M_{\text{CO}_2} = V_w \times (C_r + C_w) \times \Delta P \times \rho_{\text{CO}_2} \quad (2)$$

The formula is largely equivalent to the usual storage efficiency formula presented in Equation (1), with the storage efficiency E defined as:

$$E = (C_r + C_w) \times \Delta P \quad (3)$$

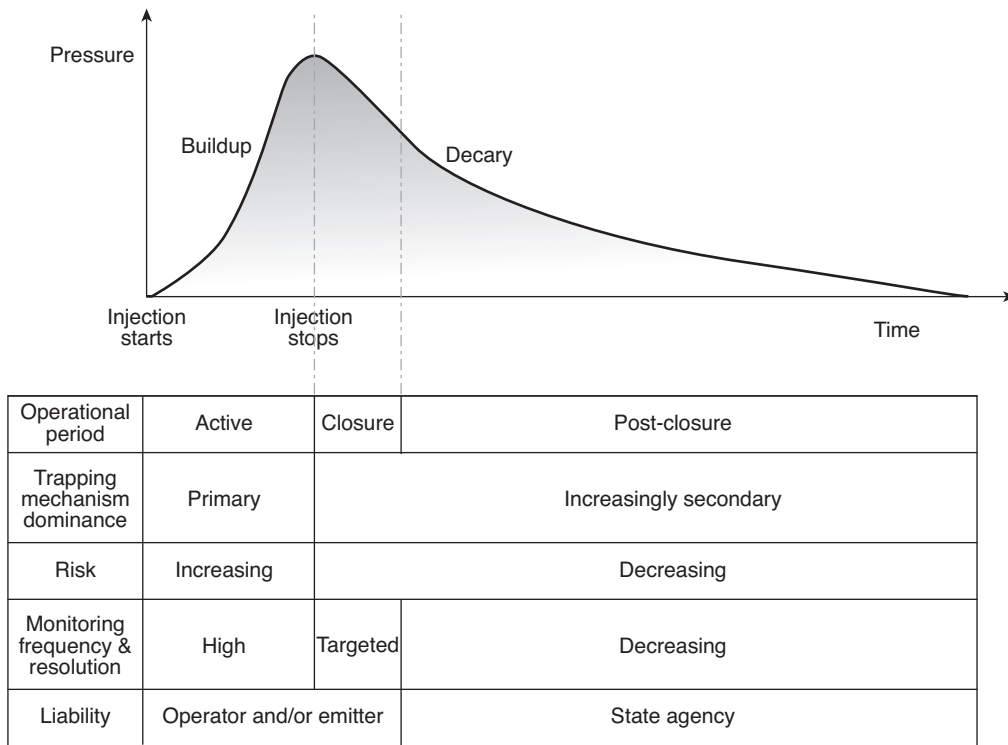


Figure 2

Relation between pressure behaviour and operational phases, dominance of CO₂ trapping mechanisms (see Fig. 1), monitoring frequency and resolution, and liability at a CO₂ storage site, from [13].

Assuming a homogeneous pressure build up in a confined aquifer, the storage efficiency coefficient is simply controlled by three parameters: the rock (or pore) compressibility, the formation water compressibility and the pressure increase.

2.2 Orders of Magnitude of Rock Compressibility

A review of rock compressibility was performed by Newman [15], with main results depicted in Figure 3.

The author distinguished three types of compressibility behaviour:

- consolidated rock, “hard” rocks (thin edges could not be broken off by hand);
- friable samples could be cut into cylinders, but the edges could be broken off by hand;
- unconsolidated samples would fall apart under their own weight unless they had undergone special treatment such as freezing.

Interestingly enough, rock compressibility covers up to 2 orders of magnitude from a consolidated rock to an unconsolidated sandstone and the compressibility range is larger for porosities over 20% where a large scatter is noted.

2.3 Orders of Magnitude of Water Compressibility

Brine compressibility are plotted in Figure 3 as a function of formation depth:

- for two temperature gradients (30 and 50 C/km); and
- two NaCl salinities (30 and 200 g/L).

Apart from rather extreme depths that are rarely considered for aquifer CO₂ storage, the water compressibility ranges from 3 to 6×10^{-10} Pa⁻¹.

Hence the range of total compressibility will primarily be connected to the range of rock compressibility.

2.4 Allowable Pressure Increase

The geomechanical effects that can alter a geological storage site integrity include hydraulic fracturing of the cap rock, fault reactivation, thermal fracturing of the reservoir with fracture propagating to the cap rock and loss of well integrity. The primary risk, controlling the maximum injection pressure, is often identified as the hydraulic fracturing of the cap rock.

In order to avoid hydraulic fracturing risk:

- the minimum stress profile is established in the selected basin, ranging typically from 15 MPa to 20 MPa per km of burial;

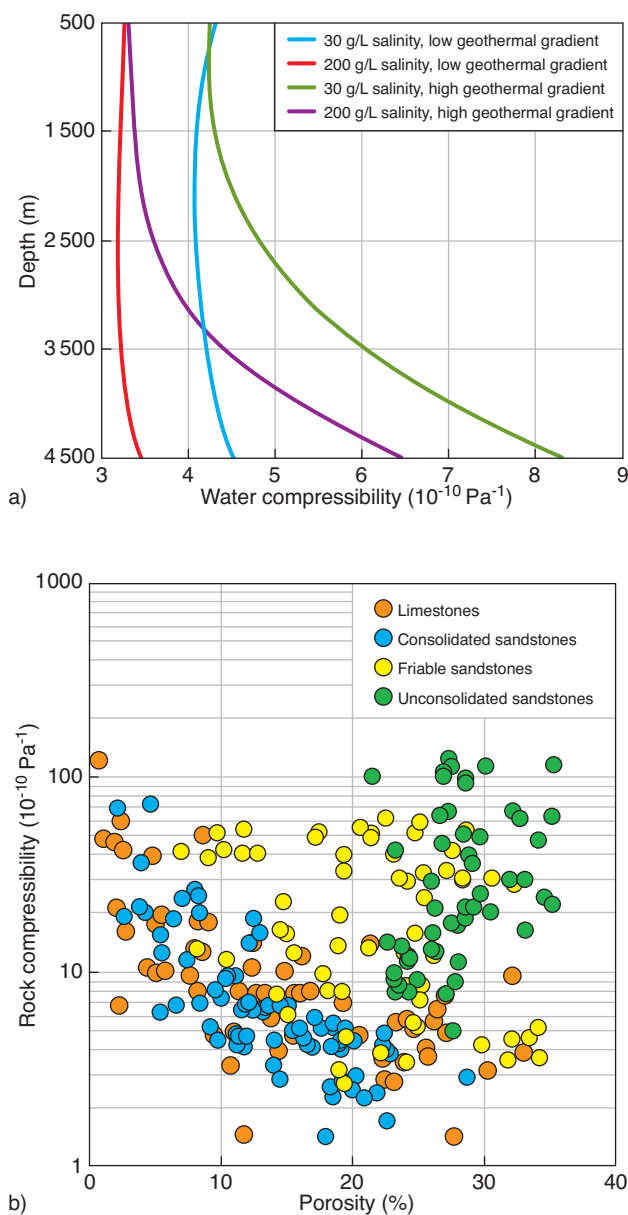


Figure 3

a) Rock compressibility as a function of porosity from Newman [15] and b) water compressibility as a function of depth.

- a safety margin (for example 90%) is taken on the maximum injection pressure, leading to a maximum injection pressure from 13.5 MPa to 18 MPa per km of burial;
- when applied on a hydrostatic basin (initial pressure around 10 MPa/km), one finds that the maximum pressure increase will range between 3.5 and 8 MPa/km.

These are orders of magnitude; the maximum injection overpressure has to be assessed on a case by case reviewing

all possible failure modes of the geological integrity. Also note that in specific basins, regulations can be in place limiting the maximum injection pressure.

The other possible constraint on the maximum CO_2 pressure is related to the CO_2 capillary entry pressure into the cap rocks.

As pointed out by several authors (see for example [16]), gas entry pressure into cap rocks is smaller for CO_2 than many other gases due to the low CO_2 -water interfacial tension.

In the case of the cap rock of the Utsira sand, an entry pressure of 1.7 MPa for supercritical CO_2 was measured [17], at a depth of 900 m, equivalent to a gradient of 1.9 MPa/km.

The entry pressure measurement was converted into a CO_2 column of 300 m, hence a column even thicker than the whole Utsira sand. This calculation assumes that the water pressure in the aquifer is not affected by the CO_2 storage operations.

For an industrial CO_2 storage, aquifer pressure is to increase but the water pressure in the cap rock above the CO_2 gas cap may remain largely unchanged as the CO_2 will act locally as a barrier to water flow to the cap rock. So the overpressure of the CO_2 gas cap to the cap rock will primarily be connected to the aquifer overpressure but not to the CO_2 column thickness.

Hence, to ensure no CO_2 entry into the cap rock, the aquifer pressure increase has to stay below the CO_2 entry pressure of the cap rock, whatever the CO_2 column thickness.

2.5 Consequences for Storage Efficiency Coefficients

Table 2 summarizes orders of magnitudes of storage coefficient E based on the pressure approach (Eq. 3). It uses values of the different parameters presented in Sections 2.2 to 2.4.

Section 2.2 has reviewed typical values of rock compressibilities. It concludes that for consolidated materials with porosity over 10%, rock compressibility is in the range of $5.0 \times 10^{-10} \text{ Pa}^{-1}$. We consider this value as a standard rock compressibility for calculations of the storage efficiency coefficient E . Alternatively, the case of an unconsolidated sandstone is considered, derived from Utsira measurements, with a rock compressibility of $80.0 \times 10^{-10} \text{ Pa}^{-1}$, showing a large contrast to the standard rock compressibility.

Section 2.3 has indicated that water compressibility always remains close to $4 \times 10^{-10} \text{ Pa}^{-1}$ in aquifer storage conditions. As such no sensitivity to this parameter is performed.

Section 2.4 has presented different ranges of maximum pressure increases in the aquifers:

- we consider as a standard case a maximum overpressure of 3.5 MPa/km;
- as a first alternative case, we consider a compressive basin where maximum overpressure could reach 8 MPa/km without risks of hydraulic fracturing of the cap rock;

TABLE 2
Storage coefficient per km of burial based on the pressure approach

		Capillary entry controlled	Standard case	Compressive basin	Unconsolidated sandstones
Rock compressibility	10 ⁻¹⁰ Pa ⁻¹	5.0	5.0	5.0	80.0
Water compressibility	10 ⁻¹⁰ Pa ⁻¹	4.0	4.0	4.0	4.0
Total compressibility	10 ⁻¹⁰ Pa ⁻¹	9.0	9.0	9.0	84.0
Max pressure increase	MPa/km	1.9	3.5	8.0	3.5
Storage coefficient <i>E</i>	%/km	0.17	0.31	0.72	2.9

TABLE 3
Utsira CO₂ storage capacities from published studies and this paper, based in Equation (3)

Study	References	Rationale	Aquifer pore volume (km ³)	Storage efficiency <i>E</i>	CO ₂ density (kg/m ³)	CO ₂ density (Gt)
Joule II	[8]	Total capacity	1 092	6%	769	50.4
Joule II	[8]	In traps	1 092	0.12%	769	1.0
GESTCO	[9]	Total capacity	918	6%	769	42.4
GESTCO	[9]	In traps	918	0.12%	769	0.8
CO2Store	[1]	In traps	600	0.11%	500	0.3
This paper		Total capacity	600	1.4%	500	4.2
Lindeberg	[19]	Water prod.		~7%		20-60

– as a second alternative case, we consider a maximum overpressure derived from a CO₂ entry pressure into the cap rock, calculated from the Utsira case.

The yellow cells are those where alternative values are replacing the standard values described above.

From this table, one notes that it may be difficult to reach $E = 4\%$ as discussed in Section 1.2, unless the geological formation is highly compressible.

As a reminder, some key assumptions are made to derive these numbers:

- the water pore volume of the aquifer is completely closed and no water is expelled from the aquifer as a consequence of the CO₂ storage operation;
- pressure can build up homogeneously in the aquifer (meaning that the well spacing at regional scale has to be adapted to the injectivity to ensure a homogeneous pressure increase);
- CO₂ remains in a dense phase in the aquifer.

2.6 Discussion on Utsira Storage Capacities

Sleipner project has been injecting near 1 Mt CO₂ per year into Utsira formation since 1996 [12]. Hence, Utsira aquifer CO₂ storage capacity has been largely studied.

Table 3 summarizes some previously published Utsira CO₂ storage capacities, and compares those with the pressure approach.

For the pressure approach, a rock compressibility of $80 \times 10^{-10} \text{ Pa}^{-1}$ is taken, after [18] and a maximum pressure increase of 1.7 MPa is derived from the capillary entry pressure measurement [17] leading to a storage coefficient of 1.4%.

These two values (rock compressibility and capillary entry pressure) were measured at Sleipner injection area, and may not be representative of the whole Utsira aquifer as rock compressibility may be very heterogeneous and the capillary entry pressure measurement may not be representative of the effective seal of the Utsira.

For this work, aquifer pore volume and average CO₂ density are kept from a previous study.

Study from Lindeberg assumes water production to mitigate pressure build up in the Utsira, and will be discussed further in Section 5.

One notes a large range of uncertainty in the storage capacity coefficient *E*, almost two orders of magnitude. With the pressure approach, the storage efficiency is reasonably high ($E = 1.4\%$), but this high value is due to the assumption that Utsira sandstone is unconsolidated.

As a consequence, larger *E* coefficients for Total Capacity assessments in Joule II and GESTCO studies implicitly

require some volume of water is removed from the aquifer, either because Utsira is open to the sea floor; or because some formation water can flow into the cap rock; or because it is produced by dedicated wells.

3 NEGATIVE EFFECTS ON CO₂ STORAGE CAPACITY – DOWNSIDES

An important assumption when computing the storage capacity using Equation (2) is the fact that pressure build up can be homogeneous in the whole aquifer.

There are two major reasons not to be able to achieve a homogeneous pressure build up in an aquifer:

- lack of rock connectivity (changes in facies, thickness, permeability, presence of faults);
- large pressure drops at injectors location.

In the case of large pressure build up heterogeneities, the maximum allowable pressure increase will be obtained at injector wells, with a lower pressure increase elsewhere and, as a consequence, a lower average pressure increase than the maximum allowable pressure increase.

This effect was modelled for a typical aquifer [2, 20]:

- local pressure increase to honour injectivity can reach 10 MPa for the aquifer studied;
- average pressure increase to inject a given mass of CO₂ with time will be directly proportional to the size of the domain and Equation (2), ranging from 1 to 24 MPa in the case studied.

These papers illustrate the fact that local pressure increase at wells to honour injectivity can be very high compared to typical geomechanical / capillary entry constraints, hence average pressure increase in the aquifer is much smaller than pressure increase at wells, and in the case of a closed aquifer it may not be technically feasible to increase the average aquifer pressure up to the maximum allowable increase while injecting with significant CO₂ rates.

Alternatively, a very high density of wells may be required (at regional scale) to ensure a significant average pressure build up of the aquifer, which may increase significantly the costs of geological storage.

As such a down side coefficient could be applied to Equation (3) to take into account the fact that the average pressure increased will be only a fraction of the maximum allowable pressure increase coming from geomechanical and/or capillary entry constraints.

4 POSITIVE EFFECTS ON STORAGE CAPACITY – UPSIDES

Three possible upsides are discussed that could limit pressure build up during the injection: CO₂ dissolution in the formation water; formation water flow to open boundaries of the aquifer; formation water flow to the cap rocks.

4.1 Dissolution of CO₂ in the Formation Water

As underlined by various authors [12], CO₂ dissolution is a significant trapping mechanism and saturating formation water with CO₂ would create huge CO₂ storage capacities [4].

Nevertheless, it is also indicated that dissolving CO₂ is a long process, coupling molecular diffusion and gravitational instabilities in the formation water (*Fig. 1*). On Utsira case, dissolution processes is expected to develop from 300 to 5 000 years after the injection period [1], 1 000 year period is modelled to dissolve the CO₂ in [20], a parametric study is presented in [21] illustrating the impact of the permeability anisotropy on the time required to dissolve the CO₂, with 25% of the CO₂ being dissolved after 300 to 20 000 years depending on the k_v/k_h ratio.

As such, CO₂ is expected to significantly dissolve a long time after the end of the injection period. For an industrial storage project, the question is then how much CO₂ can reasonably dissolve during the injection period, which could reduce the pressure pulse due to the CO₂ injection?

Simple assumptions are made to evaluate the fraction of CO₂ that can dissolve during the injection period. Indeed, CO₂ injection results in drainage processes only, no imbibition is to take place before injection stops; CO₂ dissolves into formation water in direct contact with the CO₂ dense phase, and molecular diffusion (transportation of dissolved CO₂) can be neglected; the formation water in direct contact with CO₂ in dense phase is the residual water in CO₂ flooded areas.

With typical numbers of 20% residual water saturation, a CO₂ content of the CO₂ saturated aqueous phase of 50 kg/m³ and a CO₂ density of 500 kg/m³, one gets:

- dissolved CO₂ mass per unit of pore volume of:
 $20\% \times 50 = 10 \text{ kg/m}^3$;
- dense phase CO₂ mass per unit of pore volume of:
 $80\% \times 500 = 400 \text{ kg/m}^3$.

Hence, less than 3% of the CO₂ is to dissolve in the formation water.

Moreover, as indicated in [21], the apparent partial molar volume of dissolved CO₂ is in the range of 30-40 cm³ in geological storage conditions, to be compared with 88 cm³ for a 500 kg/m³ dense phase CO₂. So, even if all the injected CO₂ dissolves in the water, it would take as much space as a dense phase CO₂ with a density from 1 100 to 1 500 kg/m³, leading to similar pressure build up issues in the aquifer.

As a consequence of these, a very limited fraction of CO₂ is expected to dissolve in the formation water during the injection period and this dissolution is expected to have a minor impact when it comes to pressure build up due to CO₂ injection.

4.2 Open Boundary Conditions

An open aquifer is modelled by applying a constant pressure at the shallowest side of the aquifer.

Figure 4 provides a schematic of a dipping aquifer:

- injection is assumed to be at a depth of 1 km, in a 0.2 km thick aquifer;
- out crop of the aquifer at sea level, at 100 km distance from the CO₂ storage area;
- storage extension in the third dimension is assumed to be 20 km.

We assume that the water pressure gradient is increased as a consequence of the storage operation in the whole basin: $P = \alpha \times \rho_w g z$, with α between 1.35 and 1.8 (see Sect. 2.4).

This increase of pressure gradient initiates a water flow from the storage area to the out crop:

$$Q_w = -H \times \frac{k \times h}{\mu_w} \times \frac{\partial}{\partial x} (\alpha \times \rho_w g z - \rho_w g z) \quad (4)$$

$$\approx H \times \frac{k \times h}{\mu_w} \times \theta \times (\alpha - 1) \times \rho_w g$$

Equation (4) overestimates the water flow in the system as it assumes a steady state flow at basin scale and does not account for time lag between CO₂ injection and flow movement within the basin [22, 23].

The displacement of this volume of water would compensate the injection of the same volume of CO₂ at storage conditions.

As a consequence of both the dip and the pressurisation of the aquifer, the CO₂ would also have a tendency to flow towards the out crop.

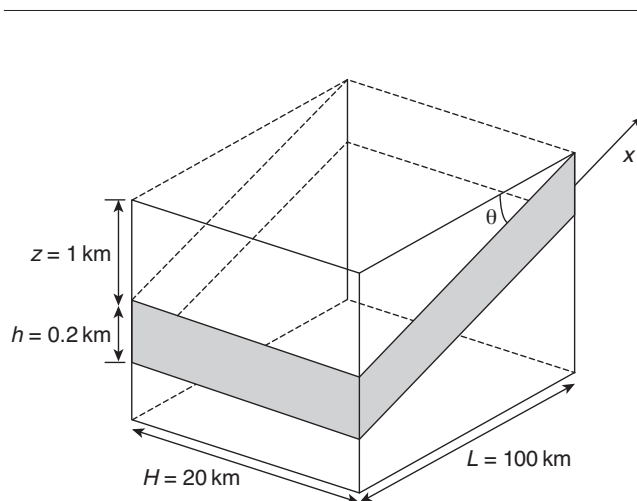


Figure 4
Sketch of an aquifer with a structural dip θ and dimensions.

The front velocity of a CO₂ layer (with a relative permeability of 1.0) would be:

$$v_{\text{CO}_2} \approx -\frac{k}{\phi \times \mu_{\text{CO}_2}} \frac{\partial}{\partial x} (\alpha \times \rho_w g z - \rho_{\text{CO}_2} g z) \quad (5)$$

$$\approx \frac{k}{\phi \times \mu_{\text{CO}_2}} \times \theta \times (\alpha \rho_w - \rho_{\text{CO}_2}) \times g$$

Both the CO₂ front velocity and the water movement are proportional to the dip of the aquifer. High dip is required to accelerate water movement to the boundary conditions but also favours a rapid migration to the outcrop.

A numerical application is made using:

- geometrical parameters $H = 20$ km, $h = 200$ m, $\theta = 1\%$, $\alpha = 1.35$;
- permeability of 1 Da = 10^{-12} m² and porosity of 15%;
- water and CO₂ density respectively of 1000 and 500 kg/m³;
- water and CO₂ viscosity respectively of 6×10^{-4} and 3×10^{-5} Pa.s.

One gets a flow of water of 20 000 m³/day equivalent to a CO₂ injection rate of 3.6 Mt/yr and a CO₂ front velocity of 0.6 km/year.

This numerical application illustrates the fact that a significant increased CO₂ capacity can be obtained from displacing pore water towards the boundary conditions, but this capacity is significant only for highly permeable, thick and continuous aquifers for which migration of the CO₂ will become a concern.

One has to remember that in order to assess this impact, it is necessary to characterize aquifer connectivity at large scale (involving sedimentology, faulting, etc.) and to model the pressure response with a model at the same large scale with correct boundary conditions, as the dimensions of the aquifer will directly impact the pressure response [20]. Any small scale model with either constant pressure boundary condition or infinite aquifer boundary condition would drastically underestimate the pressure build up at the injectors and hence overestimate the CO₂ storage capacity.

4.3 Formation Water Flow Through Cap Rocks

A possible process that could expulse formation water from the pore space of the aquifer and release pore space for CO₂ storage is formation water flow into the cap rocks [24].

Indeed, if formation pressure increases in the aquifer while CO₂ pressure remains below capillary entry pressure of the cap rock, CO₂ will remain stored in the aquifer while some formation water will be displaced to the cap rock.

The cap rock would hence act as a selective filter, allowing formation water to leave the aquifer; but acting as a barrier to CO₂ escape from the aquifer. Indeed, the CO₂ will accumulate in limited surfaces below the cap rock, leaving most of the interface between aquifer and cap rock open to formation water flow.

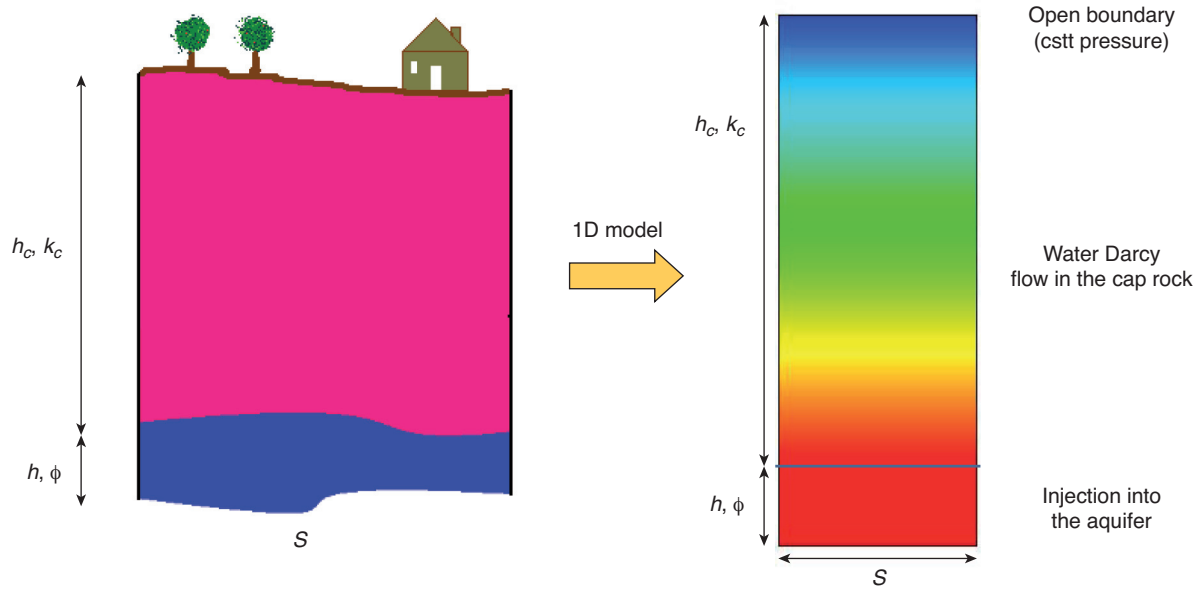


Figure 5

1D representation of formation water flow through a cap rock.

Some simple 1D models were set up in order to model this process, as sketched in Figure 5.

Key assumptions are:

- horizontal pressure changes, induced by well location and boundary conditions, are neglected;
- hence, pressure build up is homogeneous in the aquifer;
- single phase, Darcy equation is used to model formation water flow through the cap rock;
- no CO₂ flow is modelled through the cap rock as CO₂ is assumed to be retained in the aquifer due to capillary entry pressure;
- constant boundary conditions are used at the top of the model.

The modelling can be summarized with the following equations:

$$\begin{cases} Q_{cap} = \frac{M_{CO_2}}{T \times \rho_{CO_2}} = \frac{S \times h \times \phi \times (C_r + C_w) \times \Delta P}{T} \\ Q_{cap} = \frac{S \times k_c}{\mu_w} \times \frac{\Delta P}{h_c} \end{cases} \quad (6)$$

where:

- Q_{inj} and Q_{cap} are respectively the CO₂ injection rate and the formation water flow through the cap rock once a steady regime is set up, both expressed in pore volumes per time unit;
- Q_{inj} is computed as a ratio between the storage capacity and the project injection duration T ;

- Q_{cap} is derived directly formation water Darcy flow through the cap rock due to the overpressure ΔP in the aquifer, once steady conditions are obtained, assuming no overpressure at the top of the cap rock (open boundary condition).

The issue here is to know whether the cap rock vertical permeability is large enough so that water flow through the cap rock would compensate volumetrically the CO₂ injected in the aquifer. Equating the two rates, one calculates a permeability threshold k_T .

$$k_T = h_c \times h \times \frac{\phi \times (C_r + C_w) \times \mu_w}{T} \quad (7)$$

Based on the effective cap rock vertical permeability and how it compares to the permeability threshold k_T :

- if $k_c \ll k_T$ then the formation water flow through the cap rock will be negligible and the cap rock permeability will have no effect on the storage capacity;
- if $k_c \gg k_T$, the CO₂ volumetric rate will be compensated by an equivalent volumetric rate of formation water through the cap rock, hence the CO₂ storage capacity of the aquifer will no longer be limited by the pressure effect.

As such, it is recommended to quantify k_T on a case by case basis and see whether it is in the range of a cap rock vertical permeability. If flow through cap rocks is expected to be significant, characterization of the cap rock vertical permeability has to be performed at basin scale in order to provide relevant input to a flow model incorporating this effect (see [23] for a modelling example).

This characterization is difficult as average vertical permeability of a cap rock can be controlled by local very low permeability layers that may be difficult to detect and quantify; and cap rock data are scarce, leading to a potentially difficult horizontal extrapolation at basin scale.

As a consequence, it may be technically difficult to assess the water flow through cap rocks from available characterization data. This water flow can be evaluated along a CO₂ storage operation when collecting pressure data resulting from the injection operation.

5 ALTERNATIVE CO₂ STORAGE STRATEGY: WATER MANAGEMENT

The previous sections have underlined that aquifer CO₂ storage capacity may be limited by pressure build up in the aquifers, either locally (near wells) or not (general pressure build up in the aquifer).

This pressure constraint is due to the fact that CO₂ aquifer storage is primarily CO₂ injection into hydrostatic, aquifer formations, meaning that no pore space is available for the CO₂ that will enter the aquifer thanks to pressure build up. This is very different from depleted gas reservoir CO₂ storage, where hydrocarbon gas was removed, and can be replaced by CO₂; or Enhanced Oil Recovery (EOR), where CO₂ will progressively replace oil in the pore volume.

In order to limit pressure build up in the aquifer as a consequence of CO₂ injection, formation water can be extracted from the same aquifer, and injected elsewhere or treated and used at surface.

This strategy has been proposed by various authors, in order to store CO₂ in rather small structures in Browse Basin, Australia [25]; as a pressure relief strategy for the Gorgon Australian project [26]; or as a way to increase Utsira CO₂ storage capacity [19].

Concerning the Utsira [19], the results can be compared to storage capacity obtained by CO₂ injection only in the same aquifer, as shown in Table 3: storage capacity could be increased from 4.2 Gt without water production to 20 to 60 Gt with water production. The CO₂ capacity from [19] is limited by the number of CO₂ injectors, water producers and CO₂ recycling to the water producers.

This water management strategy may or not be feasible depending on the local setting (onshore *versus* offshore, for example). When feasible, its implementation would increase significantly the CO₂ storage capacity of a given aquifer.

CONCLUSIONS

The objective of the paper is to demonstrate that pressure build up during CO₂ geological storage operations may adversely impact the CO₂ geological capacity of an aquifer.

As such, CO₂ geological storage efficiency should be primarily based on a pressure approach (*Eq. 2*) rather than on a volumetric approach. This assessment is based on simplifying assumptions, and is to be used for ranking and screening purposes.

This storage capacity assessment has to be complemented with a CO₂ injectivity assessment into a given aquifer. Indeed, the CO₂ injector density (spacing) at regional scale required to achieve a given CO₂ storage capacity will depend largely on the aquifer quality (mainly thickness, permeability and continuity).

As such, after the screening phase, it is recommended to perform detailed studies in order to model these effects based on the knowledge of a given aquifer, its extension and its cap rock.

Care should be taken not to use small scale reservoir flow models with optimistic boundary conditions as constant pressure boundary conditions or infinite aquifer boundary conditions.

Finally, water production appears to be an attractive strategy in order to tackle the pressure build up issue and, hence, to increase the storage capacity.

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