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Energy Procedia 114 (2017) 3157 – 3166

Energy Procedia

13th International Conference on Greenhouse Gas Control Technologies, GHGT-13, 14-18 November 2016, Lausanne, Switzerland

Investigation of caprock integrity due to pressure build-up during high-volume injection into the Utsira formation

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Abstract

In this work, we investigate the pressure-limited storage capacity of the Utsira formation. We employ the use of a simple capacity estimate based on maximum sustainable pressure. Here, the pressure during injection or post-injection cannot exceed the least compressive stress at the base of the caprock at any location. Given the global capacity estimate, large-scale simulations are performed to determine if the global capacity can be reasonably attained given local injectivity constraints and long-term CO_2 trapping. We find that the Utsira can withstand injection rates over 100 Mt/y for 50 years, which is equivalent to 8.3 Gt of CO_2.

Peer-review under responsibility of the organizing committee of GHGT-13.

Keywords: CO_2 storage capacity; caprock integrity; injectivity; storage security; VE model; maximum sustainable overpressure; geomechanical deformation

1. Introduction

In order to have a significant impact on climate change mitigation, global CO_2 emissions must be reduced significantly by 2050. The European Union has called for CO_2 emissions reductions of 80% below 1990 levels by 2050, which is equivalent to 80 Gt of CO_2 being kept out of the atmosphere through a combination of renewables,

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Peer-review under responsibility of the organizing committee of GHGT-13.
doi:10.1016/j.egypro.2017.03.1444

increased efficiency and CCS [1]. CCS alone is expected to account for 12.2 Gt of CO_2 emissions avoided by 2050, which implies average injection rates of 400 Mt/year. With few acceptable onshore storage locations for such large volumes of CO_2, Europe will necessarily depend on the large capacity and relative safety of offshore CO_2 storage in the North Sea. One proposed strategy is to develop a central storage site on the Norwegian continental shelf that has sufficient capacity to handle a majority of the captured CO_2 that is transported from Europe by pipeline or ship.

Nomenclature

α_B	bulk compressibility, Pa^{-1}
β_w	water compressibility, Pa^{-1}
β_T	total compressibility, Pa^{-1}
ρ_w	seawater density, kg/m^3
ρ_b	formation water density, kg/m^3
ρ_s	wet bulk density, kg/m^3
σ_h	minimum horizontal stress, Pa
σ_v	lithostatic stress, Pa
ϕ	porosity
Δp_{max}	maximum sustainable overpressure, Pa
d	formation depth below sea bottom, m
g	gravitational acceleration, m/s^2
h_{sea}	sea depth, m
p	pore pressure, Pa
p_0	initial pore pressure, Pa
z	depth below sea level, m
V_f	formation pore volume, m^3
V_0	initial formation pore volume, m^3

Capacity estimates are important for understanding the suitability of aquifers for large-scale CO_2 storage and for identifying a suitable central storage site. On the Norwegian continental shelf, estimates of storage capacity for prospective aquifers have been published in a series of storage atlases (e.g. [2]). Quantification of CO_2 storage capacity is typically performed using a combination of pore volume, boundary conditions (closed vs semi-closed), and storage efficiency. The latter parameter is the percentage of the aquifer that can be filled with injected CO_2, and is typically on the order of a few percent. However, there is little physical basis for the chosen value of storage efficiency and few sufficiently large-scale computational studies to justify the parameter choice. Generally speaking, these types of storage efficiency based estimates have limited utility because they do not indicate how the calculated capacity can be practically achieved. Further consideration is needed for local injectivity issues and long-term trapping.

Pressure-based capacity estimates have been proposed that take into account the pressure impact on storage capacity [3]. These simple functions give a first-order estimate of volume change for a given overpressure in closed and semi-closed systems and are typically applied to the entire volume assuming constant properties. Although the estimates are quick and simple to calculate, little guidance is given on the choice of the maximum sustainable overpressure, a crucial input to the estimate. Additionally, these global estimates do not address local injectivity or long-term storage trapping of the volume of CO_2 that the formation can theoretically store.

1.1. Approach

We propose a two-step method to estimate the pressure-limited capacity of a formation. First, we perform a evaluation of the caprock to identify the maximum overpressure that can be withstood at any point in the seal at any time. This *global* allowable overpressure is used as input into an existing analytical method to estimate for CO_2 capacity to determine the allowable increase in storage volume. Second, we perform local-scale storage simulations that inject the total CO_2 mass given by the global-scale capacity evaluation. These simulations will determine whether there is sufficient local injectivity and long-term storage security to safely handle the desired rate of CO_2 injection.

We apply this approach to a North Sea aquifer and investigate the pressure-limited capacity given the integrity of the caprock, which can be estimated from its mechanical properties and *in-situ* stress conditions, and the hydromechanical properties of the formation itself. Together, these characteristics of the storage complex give an estimate of the globally limiting overpressure that defines the CO_2 capacity, and the local conditions that define the injectivity and trapping mechanisms. Because the caprock and formation properties are often uncertain, we perform the evaluation under different assumptions about the hydromechanical parameters.

1.2. Utsira formation

The NPD Storage Atlas estimates that the Utsira/Skade aquifer system has approximately 15 Gt of CO_2 storage capacity, which is equivalent to 500 Mt/yr of CO_2 injection for the next 50 years [2]. With such large estimated capacity, the Utsira has the potential to become a central storage site for storage of projected EU emissions. Also, CO_2 storage in the Utsira has been underway since 1996 at the Sleipner platform. Approximately 1 Mt/y of CO_2 is injected annually into the Utsira, and it is the longest running and most successful CO_2 storage project to date [4].

Utsira storage capacity has been the subject of several studies [5,6], but none have systematically evaluated the large-scale, long-term pressure-limited capacity of the entire formation and the impact on the seal integrity of the caprock. A recent study [7] performed a series of poroelastic simulations to study deformation in the Utsira under large-volume injection. The conclusions point to the large sensitivity of reservoir dilation to the Young's modulus of the Utsira sand.

The Utsira formation is a relatively homogeneous, high permeability unconsolidated sand [8]. The caprock seal (Nordland shale) is a young, unconsolidated shale that extends up to the sea sediments [9]. Table 1 lists the relevant parameters of the Utsira sand and the Nordland shale. The hydromechanical parameters originate from analysis of the formation and caprock in the Sleipner injection well [9,10]. Other parameters and fluid properties are obtained from the Sleipner benchmark dataset [11]. The data for Utsira top surface, porosity and thickness (Figure 1) are provided by the British Geological Survey [8]. The gridded dataset has a resolution of 1.5 km in both latitudinal and longitudinal directions.

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Table 1. Hydromechanical parameters and fluid properties for the Utsira sand and Nordland shale.

Material/Fluid Property		Value	Units
Utsira Sand	Permeability	1	Darcy
	Porosity	0.35	-
	Young's modulus	0.42	GPa
	Poisson ratio, Biot	0.25, 1	-
Shale	Permeability	1	nanoDarcy
	Porosity	0.20	-
	Young's modulus	0.25	GPa
	Poisson ratio, Biot	0.25, 1	-
CO_2	Density	700	kg/m3
	Viscosity	0.06	cP
	Residual saturation	0.21	-
Brine	Density	1020	kg/m3
	Viscosity	0.69	cP
	Residual saturation	0.11	-

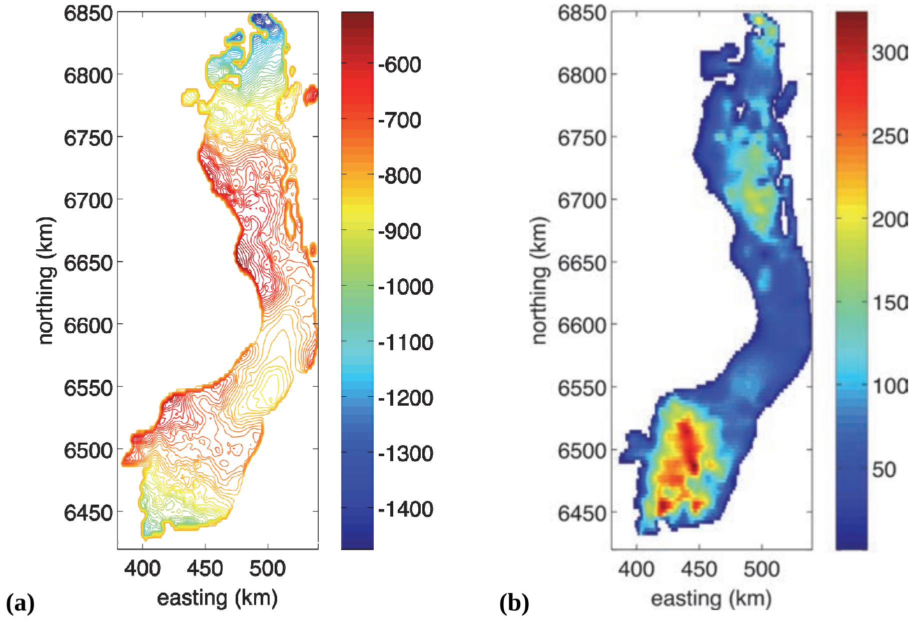

Fig. 1. Utsira formation geometry: (a) depth below sea level [m]; (b) thickness [m]. Data provided by [8].

It should be noted that the Utsira sand compressibility value reported by GEUS is relatively large [10], namely an order of magnitude larger than a typical sandstone. The data were measured in a standard compression test on a core sample that had been frozen to preserve the *in-situ* pore structure of the relatively loose sand. However, it is unclear whether a classical poroelastic model can describe the behavior of unconsolidated sand under extension with significant pore pressure increase.

2. Global storage capacity estimate

2.1. Storage capacity model

We consider the total compressibility of the system to be the sum of water and pore compressibility

$$\beta_T = \beta_w + \frac{\alpha_B}{\phi} = \frac{1}{\rho_b}\frac{\partial \rho_b}{\partial p} + \frac{1}{\phi}\frac{\partial \phi}{\partial p} \tag{1}$$

From the total compressibility, one may derive the pore volume change for a given pressure change as

$$V_f = V_0 \exp\left(-\beta_T \Delta p\right) \tag{2}$$

Following Zhou et al. 2008 [3], a linear approximation can be used in place of (2).

$$V_f = V_0 \beta_T \Delta p = V_0 \left(\beta_w + \frac{\alpha_B}{\phi}\right)\Delta p \tag{3}$$

As described in [3], Eq. (3) may be used to approximate the volume change, and thus the storage capacity of a closed system. The capacity estimation assumes a uniform increase in pressure across the entire formation. The capacity is a conservative estimate since the pressure does not dissipate through open boundaries or through a low permeability caprock. A semi-closed system will lead to a larger capacity estimate if the permeability of the caprock is sufficiently large.

The two main parameters of importance in Eq. (3) are the formation compressibility and the pressure change. Formation compressibility can be taken from measurements, but these datasets are sparse for most large-scale systems. Therefore, formation compressibility values at the global scale come with a certain degree of uncertainty, and so one should test a range of compressibility values. For the pressure change, the estimation of the maximum sustainable overpressure at a large scale is crucial. Since the system is closed, the pressure cannot dissipate. Therefore, the value of Δp in Eq. (3) should be equal to the maximum pressure that can be sustained at the base of the caprock *at any location*, even a point far from the injection well. The reason for this strict interpretation is that even though injection rates are sufficiently low for local injectivity constraints, once injection ceases, the pressure pulse will dissipate into regions where the allowable overpressure is lower or the caprock is weaker. Therefore, a longer and more global view is required for evaluation of Eq. (3).

We consider that the maximum pressure cannot exceed the least compressive stress (assuming the seal has no tensile strength) at any point during injection or post-injection. The least compressive stress can be conservatively estimated by the minimum in-situ stress, which is usually one of the horizontal stresses for formations in the North Sea. Following [12], the horizontal stress can be estimated by

$$\sigma_h = 0.053\, z^{1.145}. \tag{4}$$

For comparison, the vertical stress is given by the lithostatic pressure,

$$\sigma_v = \rho_w g h_{sea} + \rho_s g \left(z - h_{sea}\right). \tag{5}$$

And the initial pore pressure is estimated by hydrostatic pressure,

$$p_0 = \rho_w g h_{sea} + \rho_b g d\,. \tag{6}$$

From Figure 2, we see that the horizontal stress is less than the vertical stress. Therefore, the maximum sustainable overpressure at any given depth is

$$\Delta p_{\max} = \sigma_h - p_0\,. \tag{7}$$

Large-capacity storage formations have significant lateral extent, and thus the depth location of the formation top can vary significantly in space. This implies that the in-situ stresses on the base of caprock will also vary in space.

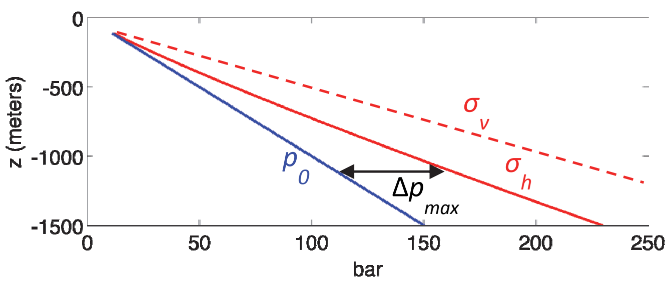

Fig. 2. Depth trend in hydrostatic pressure (blue), horizontal stress (red) and lithostatic stress (red dash).

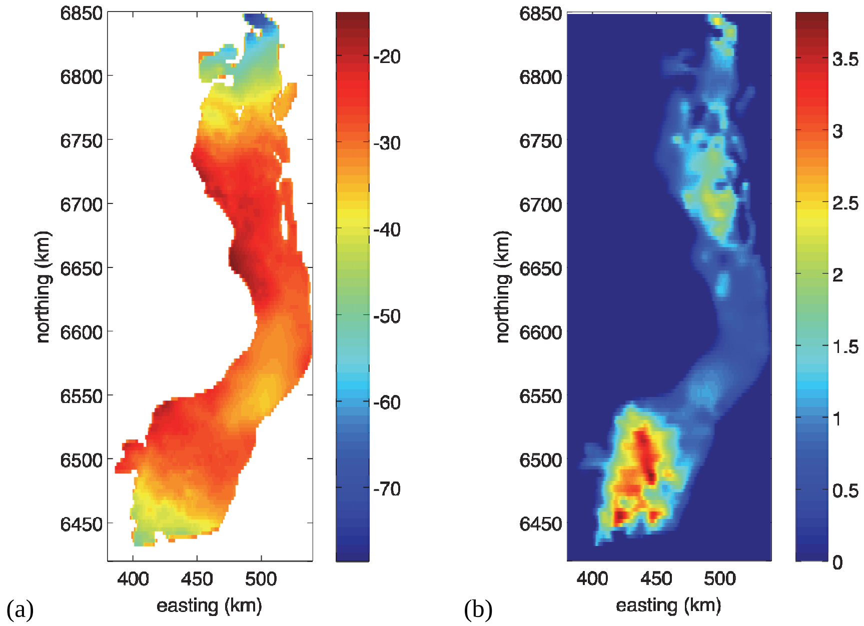

Fig. 3. (a) maximum sustainable overpressure at the caprock base [bar]; (b) estimated CO_2 storage capacity per 2.25 km^2 [Mt].

2.2. Application to the Utsira

A map of the maximum sustainable overpressure at the base of the Utsira seal is calculated from Eqs. (4) and (7), see Figure 3a. As discussed above, the minimum stress occurs at the shallowest portion of the formation. Thus, the maximum overpressure that can be sustained is equal to approximately 15 bar. The global pressure-limited storage capacity was calculated for the Utsira formation by applying the maximum overpressure of 15 bar and the GEUS measurement for compressibility into Eq. (3). The resulting pore volume increase gives a storage capacity of 8.3 Gt, assuming a uniform CO_2 density of 700 kg/m3. Even with the relatively high compressibility value from the GEUS data, the maximum overpressure of 15 bar limits the storage capacity to 55% of that predicted by the NPD Storage Atlas. The same maximum overpressure combined with a lower compressibility value more typical of a sandstone formation gives a storage capacity of 2.4 Gt CO_2. The values are summarized in Table 2.

Table 2. Global storage capacity estimate for the Utsira formation given a maximum sustainable overpressure of 15 bar.

	GEUS data [10]	Typical Sandstone
Initial pore volume	7.9 x 10^{11} m^3	
Formation pore compressiblity	10 GPa^{-1}	2.85 GPa^{-1}
Pore volume increase	1.5% (1.2 x 10^{10} m^3)	0.4% (3.3 x 10^9 m^3)
CO_2 mass stored	8.3 Gt	2.4 Gt
CO_2 injection rate over 50 y	165 Mt/y	50 Mt/y

The distribution of mass storage capacity over the spatial extent of Utsira is shown in Figure 3b. This distribution was obtained by calculation using Eq. (3) to obtain pore volume change in each individual grid cell in the Utsira formation. The mass storage is obtained by multiplying the pore volume change by a uniform CO_2 mass density of 700 kg/m^3. The bulk of the storage capacity is in the southern portion of the formation where the thicker sands expand to a larger absolute volume than in the middle and northern Utsira. In total, the pressure-limited capacity in the southern Utsira is approximately 5 Gt with the GEUS compressibility value from [10].

3. Local injectivity and trapping simulations

The next step is to determine whether local injectivity and storage trapping mechanisms are sufficient to ensure the safety and storage security of the globally estimated CO_2 storage capacity. This step is necessary as well because pressures can be quite large during the injection phase. Since wells are likely located in deeper parts of the aquifer, a local overpressure above the global maximum sustainable overpressure is acceptable. But, well pressures cannot exceed the local injectivity constraints, i.e. the minimum horizontal stress at the well. We expect that more than one well will be necessary for injections upwards of 100 Mt/y, but if too many wells are required to meet local injectivity constraints, then the global capacity estimate is unfeasible. In the same way, the storage capacity estimate is only practical if all injected CO_2 is permanently trapped in the formation.

To this end, a set of simulations are described where 5 Gt of CO_2 is injected in the southern portion of the Utsira over a 50 year time period at a rate of 100 Mt/y and simulated for 1000 years post-injection. The injection rate is divided equally over 9 wells. The number of wells and locations were chosen to maximize local injectivity and trapping. To help minimize pressure build-up locally, wells are located where aquifer thickness is > 200 m. In addition, the well locations are separated from each other and the aquifer boundaries by roughly equal distance. To increase structural and residual trapping, wells are located towards the down-dip portion of the formation. The well locations are not optimized for local injectivity and trapping, which is a task reserved for future work.

3.1. Simulation model

A vertical equilibrium (VE) model [13] was used to perform the simulations. Parameters used in the simulations are given in Table 1. The VE model assumes an instantaneous gravity segregation of CO_2 and brine at the time scale of the simulation. We employ a sharp interface assumption, meaning that capillary pressure between CO_2 and brine is neglected. By neglecting capillarity, the CO_2 will migrate due to pressure and buoyancy faster than if capillarity is considered, and thus reflects the "worst-case scenario" with respect to storage security [14]. Variable CO_2 properties are modeled. Residual and structural trapping processes are considered, while solubility and mineral trapping are neglected.

The VE model simulates the pressure and saturation change in the reservoir in space and time. Saturation is a depth-averaged quantity, which can be used to reconstruct the height of the CO_2 plume under the VE assumption. The dynamic aquifer thickness change can be computed in every gridblock using Eq. 3 under the assumption that the pore volume change is uniaxial along the vertical direction. For aquifers of large horizontal extent and relatively small vertical extent, this approximation is acceptable.

3.2. Results

After 50 years, the pressure locally and throughout the aquifer does not exceed the local or global pressure limits (Figure 4). The well pressures are obtained from gridblock pressure using a Peaceman-type approximation (Figure 5). Well pressures remain below the local overpressure constraints (slightly different for each well due to differing depths). After 1000 years, the pressure has dissipated and becomes more uniform at 15 bar overpressure throughout the southern aquifer, slowly spreading into the northern portion.

In terms of storage security, after 50 years, the plumes are very localized around the wells (Figure 6). In the post-injection phase, CO_2 migration towards higher elevations is slow and never spreads more than 25 km away from the injection wells. By 1000 years, all the CO_2 is trapped structurally or residually.

The pressure-induced thickness change of the Utsira that ranges from 50 cm to nearly 3 m in the regions where injection is occurring (Figure 7). After the pressure dissipates towards a more uniform distribution across the southern portion of the aquifer, the deformation reduces to under 2 m. Related geomechanical simulations [7] have shown that uplift at the seabed is approximately equal to deformation in the aquifer.

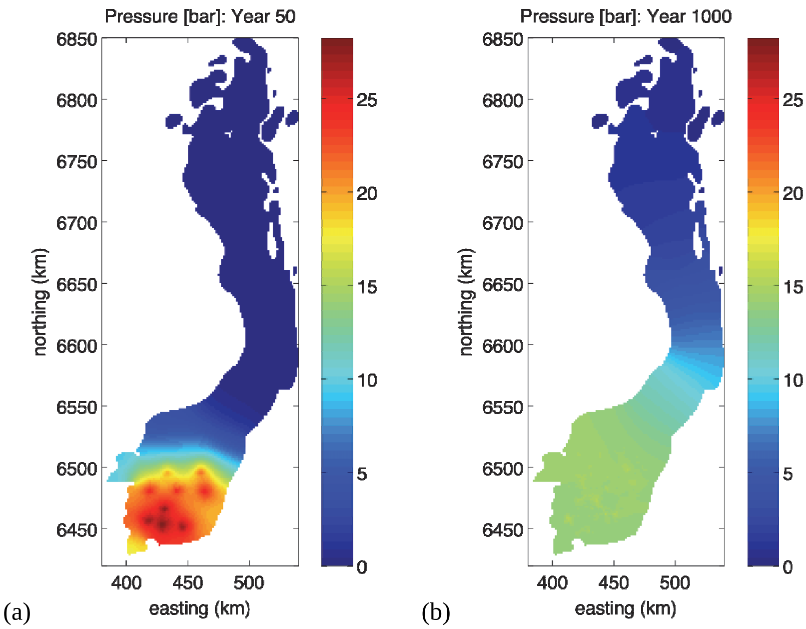

Fig. 4. Overpressure at formation top [bar] (a) 50 years; (b) 1000 years.

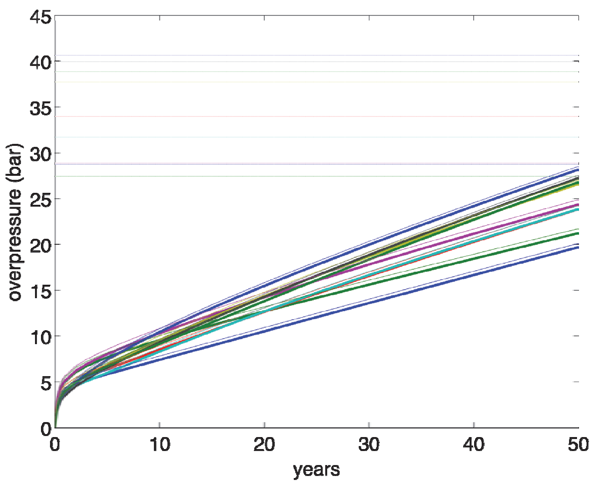

Fig. 5. Overpressure at injection wells [bar]. Dashed horizontal lines indicate allowable overpressure at each individual well.

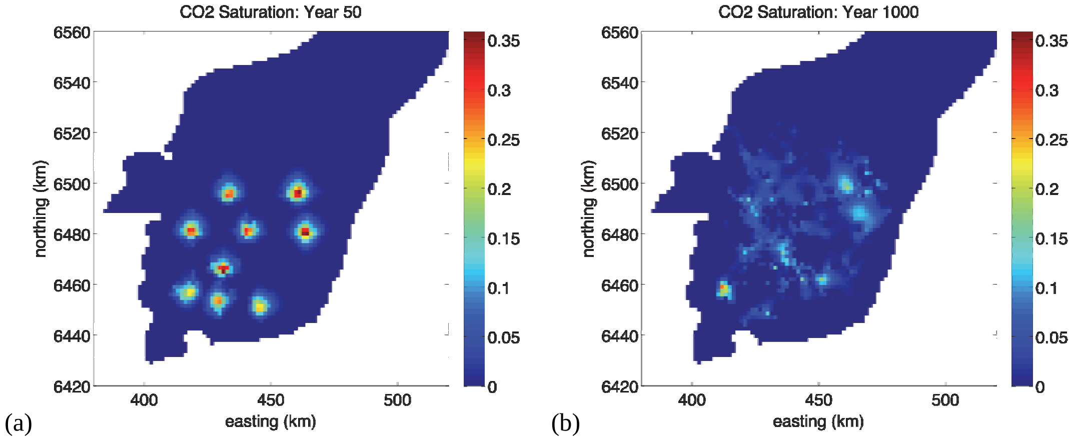

Fig. 6. Depth-averaged CO_2 saturation (a) 50 years; (b) 1000 years.

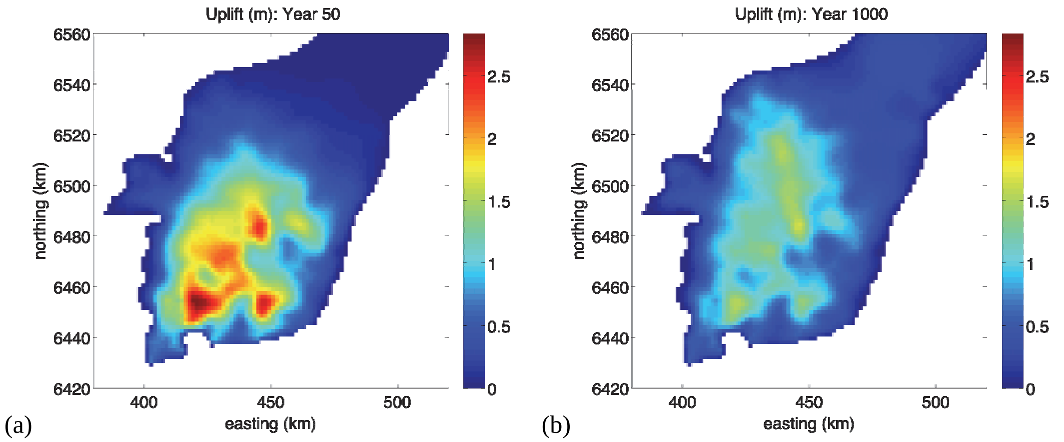

Fig. 7. Formation thickness change (approximate seabed uplift) [m] (a) 50 years; (b) 1000 years.

4. Summary and Outlook

The Utsira formation has been proposed as a candidate for large-scale CO_2 storage because of its high porosity and permeability. We have performed an evaluation of the pressure-limited capacity based on protection of caprock integrity globally and over long timescales. Using measured data from the Sleipner well, we found that the caprock can withstand 8.3 Gt of CO_2 with a uniform pressure increase of 15 bar and the assumption of a closed system. Of this capacity, 5 Gt can be stored in the southern Utsira. The capacity estimate was then used in large-scale simulations to investigate whether local injectivity constraints can be managed *without water production* and long-term storage security (trapping) is sufficiently permanent. We conclude that the global capacity of 8.3 Gt can be attained without risk of fracturing the caprock near injection wells. In addition, all of the injected CO_2 can be trapped residually or structurally within 1000 years. Some additional points are worthy of discussion:

- The Utsira is an unconsolidated sand with high compressibility. The maximum overpressure of 15 bar limits the storage capacity to approximately half of that predicted by the Storage Atlas [2]. This implies that the storage efficiency employed in [2] is too high. One may argue that the assumption of a closed system is too conservative. Assuming a semi-closed formation with open lateral boundaries or brine leakage through the caprock would result in a larger capacity estimate. However, the Nordland shale has very low permeability, so it is unclear if pressure dissipation will substantially increase the global capacity. There is also significant uncertainty about the connection between Utsira and surrounding permeable formations, e.g. Skade. This issue is part of ongoing work.

- If we assume the Utsira has a compressibility similar to a sandstone formation, then it would result in 75% less capacity than estimated here.
- Least compressive stress is one of several constraints on the sustainable maximum pressure. However, faults may be present in unfavorable orientations, and a lower maximum pressure will be required to prevent fault slip. Thus, the capacity estimate will then decrease.
- We do not consider the seal to have any tensile strength. While this assumption may be valid for sandstone formations and pre-fractured rock, shale and mudstones tend to have some tensile strength. This would allow for a higher maximum pressure than the horizontal stress, and thus an increased capacity estimate.
- We have shown that 5 Gt can be successfully stored within a 50 year period in the southern Utsira without water production. This is a large value, but it can likely be increased with co-production of water.

Acknowledgements

Funding for this study was provided by the PROTECT project (No. 233736) financed by the Research Council of Norway, Total E&P and Dea. The authors are grateful to Bahman Bohloli and Sylvain Thibeau for helpful discussions.

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