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Geomechanical consequences of large-scale fluid storage in the Utsira Formation in the North Sea

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Abstract

In this work we look at the geomechanical implications of injecting large volumes of fluid in the Utsira Formation. Our modelling is based on Biot's poroelasticity in combination with one-phase fluid flow. We study four different injection scenarios over 25 year: 1 Mt/year, 10 Mt/year, 100 Mt/year and 1000 Mt/year. We observe that the pore fluid pressure scales with the injection rate. The strain of the Utsira Formation and the related surface uplift can be estimated with simple a 1D model. A particular uncertainty with the modelling is the mechanical properties of the Utsira sand and the cap rock.

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Keywords: Geomechanics, CO_2 storage site evaluation, seabed uplift

1. Introduction

Several tens of billions of tons of global CO_2 emissions annually lead to global warming. CO_2 sequestration in aquifers and depleted oil- and gas reservoirs is considered as a promising solution for reducing the CO_2 emissions to the atmosphere [1]. But CO_2 sequestration may not be a straightforward process [2]. Challenges with CO_2 storage

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are not just to find enough pore space in the subsurface, but also to assure that the CO_2 can be injected in a safe manner, and that it will remain in place for thousands of years to come. Storage operations must therefore be carefully planned and monitored.

Nomenclature

ε	Volumetric strain [-]
σ	Mean stress [Pa]
σ_{ij}	Stress tensor, component i,j [Pa]
σ'_{ij}	Effective stress tensor, component i,j [Pa]
$\sigma^{(0)}_{ij}$	Initial stress [Pa]
$\sigma^{(1)}_{ij}$	Stress change caused by fluid injection [Pa]
p_f	Fluid pressure, [Pa]
p	Overpressure (fluid pressure – hydrostatic pressure) [Pa]
α	Biot's coefficient [-]
E	Young's modulus [Pa]
ν	Poisson's ratio [-]
ϕ	Porosity [-]
c_f	Fluid compressibility [1/Pa]
K	Bulk modulus [Pa]
K_s	Solid grain modulus [Pa]
k	Permeability [m^2]
μ	Viscosity [Pa s]
h	Aquifer thickness [m]
l_x	Lateral extent of pressure plume in x-direction [m]
l_y	Lateral extent of pressure plume in y-direction [m]
g	Gravity [m/s^2]
δ	Kronecker delta [-]

The main monitoring techniques are observations of the injection pressure, seismic imaging of the CO_2 plume, remote sensing of the surface uplift and microseismic monitoring of the rock deformations. These observations provide the modelling with important constraints for specific reservoirs.

Geomechanical modelling is a necessary tool to address the consequences of the different injection scenarios in a reservoir and to assess safe limits of the reservoir pressure. Such modelling has been done by coupling standard software tools for mechanics (e.g. FLAC) with standard tools for fluid flow in porous media (e.g. TOUGH2) [3]. Although the modelling is based on well proven geomechanical concepts, there are a number of difficult issues with model predictions. The reliability of models to make accurate and useful predictions is often related to the challenges associated with estimating rock properties with respect to fluid flow and deformations.

One of the most studied CO_2 injection operations from a geomechanical perspective is the In Salah storage project in Algeria [4]. Observations of well pressure in combination of the surface uplift and the triggering of microseismic activity have been used as constraints in a number of numerical studies [3,5-6].

In this paper, we look at the possible mechanical consequences of pressure build-up in the Utsira Formation. Utsira is an aquifer in the North Sea (see Fig. 1), which is considered a possible large-scale storage site for CO_2. Statoil has been injecting CO_2 in the Utsira aquifer since 1998 with an annual average rate of nearly 1 Mt/year from the Sleipner field. What makes Utsira Formation special is that it is a Quaternary sand with a soft Quaternary overburden. In terms of mechanical properties it is therefore different from In Salah, in addition to being a thicker aquifer.

We first look at the mechanical properties of the Utsira case and the poroelastic model. We present a simple 1D approximation, before we look at the pressure build-up and the mechanical deformations of Utsira Formation for different injection scenarios. Finally, we comment on challenges of modelling the expansion of the sand aquifer.

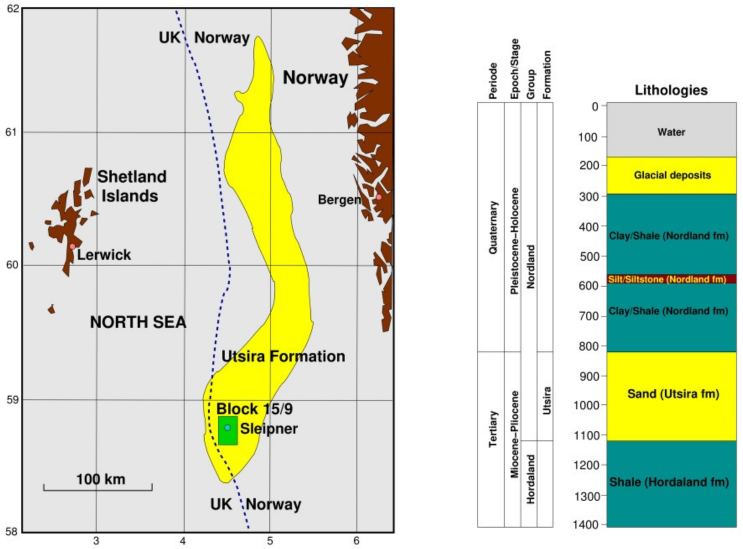

Fig. 1: (a) The Utsira Formation is a sand aquifer in the North-South direction along the West coast of Norway. It is more than 400 km long and 100 km wide. (b) The sand in the Utsira Formation is of Late Tertiary age and it is covered by Quaternary rocks in the Nordland formation, which are downwards grading from clay to shale.

2. The Utsira sand, its geology and rock properties

The Utsira Formation in the North Sea is a more than 400 km long formation of Pliocene sand with a thickness in the range from 50 m to 350 m (Fig. 1a and 1b). The porosity of the Utsira Formation is estimated to be in the range from 35-38% and the permeability is of the order Darcy (1e-12 m^2) [7]. It is covered by a 500 m thick Quaternary layer of fine grained rocks of clay and shale and by 100 - 200 m seawater [7]. The pressure and temperature conditions at the injection site of the Utsira sand are just inside the area of supercritical CO_2 [7]. The geomechanical model of the formation includes the caprock (the Nordland shale) the Utira sand and the underburden, which is shale of Tertiary age. These three units are treated as homogeneous and are assigned the following rock properties listed in Table 1.

Table 1. Lithological properties

Lithology	ϕ	k	E	ν	α
Units	-	m^2	GPa	-	-
Sand (Utsira)	0.35	1.0e-12	0.25	0.25	1
Shale (caprock)	0.2	1.0e-19	0.25	0.25	1
Shale (underburden)	0.2	1.0e-19	15.0	0.25	1

The Young's modulus (E) of the caprock is taken from measurements made during the SAC project [8]. The underburden has a typical Young's modulus for shales. Young's modulus for the sand is an important, but uncertain parameter in this study. The chosen value is larger than for the Quaternary shale, since it is of older age. The sand undergoes dilation during fluid injection, and it could be that the poroelastic regime is small in terms of strain, with a much smaller Young's modulus.

The permeability (k) of the caprock and the underburden are uncertain, but any value less than 1e-19 m^2 gives little fluid flow into the shales during the 25 years time span of injection. The Biot's coefficient (α) is assumed to be

1 in both the sand and the shale. It is a reasonable choice for the sand, which has large porosity and a large permeability, but it is probably too large for the shales. On the other hand, there is almost no fluid infiltration in the shales, and thus negligible pressure change. Therefore, an accurate value of the Biot coefficient for the shales is less important.

3. The poroelastic model

The modelling is based on Biot's poroelasticity. It is an extension of linear elasticity that takes into account the effect of the pore fluid [9-11]. Increasing the pore fluid in a porous rock leads to expansion of the rock, which demonstrates that the mechanical deformations of the rock are coupled to the fluid flow. Similarly, increasing the compressive stress on a bulk volume of the porous rock leads to a pore pressure increase, and it is therefore a coupling the other way as well, from mechanics on the fluid flow. The coupling between fluid flow and mechanics in poroelasticity is expressed by means of the effective stress

$$\sigma'_{ij} = \sigma_{ij} - \alpha p_f \tag{1}$$

which is the full stress σ_{ij} subtracted the fluid pressure p_f multiplied with the Biot coefficient α. The Biot coefficient is a number in the range from 0 to 1. In addition, it is the effective stress that deforms the rock by linear elasticity. The equilibrium equations in terms of stress then give that

$$\sigma_{ij,j} = -g\rho\delta_{iz} \tag{2}$$

where g is the constant of gravity and ρ is the bulk density. The companion single-phase pressure equation is

$$\left(\phi c_f + \frac{\alpha - \phi}{K_s}\right)\frac{\partial p}{\partial t} - \nabla\left(\frac{k}{\mu}\nabla p\right) = -\alpha\frac{\partial \varepsilon}{\partial t} \tag{3}$$

The fluid compressibility is c_f and ϕ is the porosity. The grain modulus K_s becomes infinite for rocks with $\alpha=1$, which is the case for this study. The time-derivative of the bulk strain ε appears as a source/sink-term in the pressure equation. A useful expression of the coupling between fluid pressure and deformations is

$$\sigma - \alpha p_f = K\varepsilon \tag{4}$$

where K is the bulk modulus. It shows that if the stress remains almost constant then nearly all bulk strain is proportional to the change in fluid pressure. This relation can also be used to replace the time derivative of bulk-strain with the time derivative of stress in the pressure equation.

The stress field is decomposed into two parts:

$$\sigma_{ij} = \sigma_{ij}^{(0)} + \sigma_{ij}^{(1)} \tag{5}$$

The first part is the initial stress field and the second part is the poroelastic stress caused by fluid injection. Both the full stress field and the initial stress field fulfill the equilibrium equations with gravity, which implies that the poroelastic stress field obeys the equilibrium equations

$$\sigma_{ij,j}^{(1)} = 0 \tag{6}$$

We notice that the gravity as a body force is absent, because it is taken care of by the initial stress field. The initial stress field is assumed known and it does not have to be a poroelastic solution. It is most likely the result of a complicated geological history combined with a non-trivial rheology.

The two coupled Equations (3) and (6) are solved numerically with a sequential approach [12]. The fluid flow problem is first solved with a finite volume method and the mechanics problem is solved with the finite element method using hexahedral elements. The simulator is programmed in the language C, and it has been benchmarked against analytical Theis' solution [13] for transient fluid pressure and 1D and 2D analytical solutions for deformations caused by pore fluid pressure [14]. The fluid pressure equation has the source term expressed with stress, using Equation (5), instead of the volumetric strain. This sequential formulation turns out to be unconditionally stable [12]. Boundary conditions for the pressure equation are impermeable vertical sides and base, and a hydrostatic seabed. The initial fluid pressure is also hydrostatic in the aquifer, the overburden and the underburden. Boundary conditions for the mechanics problem are free vertical boundaries, free seabed and a fixed base of the model. Recall that the base of the model is underneath the aquifer and 2 km of shaley underburden. Also, the model has lateral dimensions that are considerably bigger than the thickness, and the aquifer is laterally surrounded by shaley rocks on almost every side.

4. Condition for the validity of a 1D vertical model of uplift

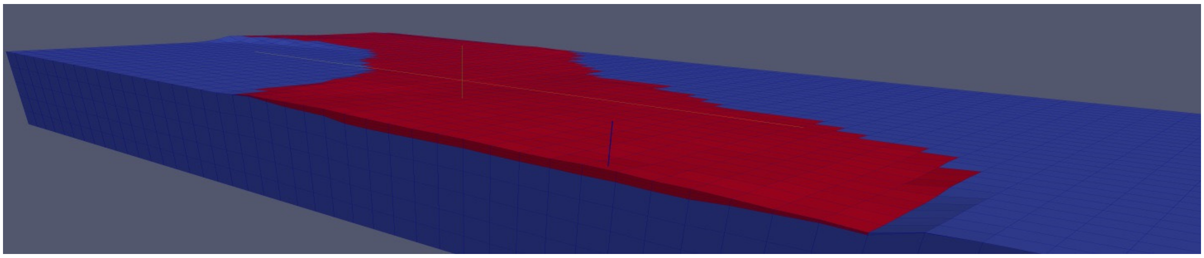

Fig. 2: A North-South vertical cut through the model where the overburden (Nordland shale) is removed. The lateral extent of the model is much larger than shown on the figure.

The 3D model has a lateral extent that is much larger than the vertical size, and it appears as 1D in the vertical direction (see Fig. 2). The aquifer thickness does not vary much over several tens of km. If the pressure plume also has smooth lateral changes, we can estimate the vertical deformations of the Utsira sand with a simple 1D model. The equilibrium equations of the poroelasticity give a simplified equation for the vertical displacement assuming a 1D vertical model. This equation can be integrated and it gives the strain when the pressure is known. There is almost no fluid flow into the shaly rocks of the overburden and the underburden. The expansion caused by an increasing fluid pressure is therefore restricted to the aquifer, and the dilation of the aquifer is approximated as

$$dh = \frac{dp}{M} h \tag{7}$$

where h is the aquifer thickness, $M=(1-\nu)E/((1+\nu)(1-2\nu))$ and dp is the pressure increase in the aquifer. This expression turns out to be a simple and useful estimate for the deformation of thin and flat aquifers like Utsira, when the pressure plume is regional in size.

5. Fluid pressure and dilation of the Utsira sand

We have conducted a series of injection scenarios in order to explore possible poroelastic deformations of the Utsira sand. The injection scenarios are simplified by considering only single-phase fluid flow. Injection is at position of the present day CO_2 injection at the Sleipner field. Injection is simulated with a source term in one cell at the vertical center of the formation. Maximum pressure build-up is in this cell. The pressure in the injection cell depends on the injection rate and the cell size. While the pressure in the other cells depends on the injection rate, it is only weakly dependent on the grid size. This behaviour of the fluid pressure is also seen when benchmarking against Theis' solution. A more sophisticated study would have replaced the injection cell by a detailed near-well model, which could represent a number of wells with a series of perforations.

Four injection scenarios were simulated, with the rates 1 Mt/year, 10 Mt/year, 100 Mt/year and 1000 Mt/year, respectively, over a time span of 25 years. The yearly average of the current CO_2 injection rate is slightly less than 1 Mt/year. An injection rate beyond 100 Mt/year might be desirable in order for Utsira to be used for large-scale CO_2 storage. Even though a realistic well design for large-scale CO_2 storage could require multiple wells distributed over the aquifer with water production, it is interesting to see the poroelastic prediction for injection restricted to a single well in the Sleipner field.

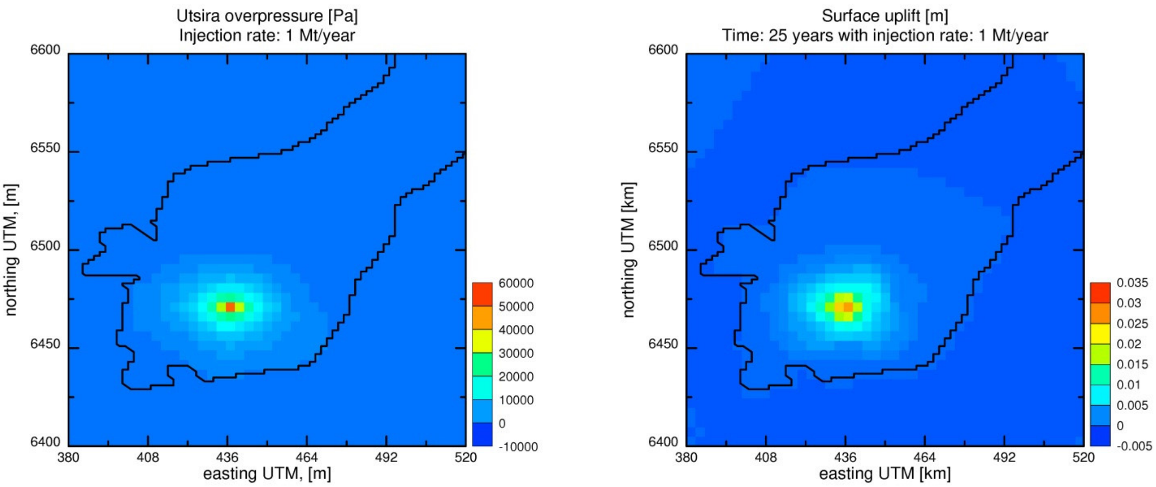

Fig. 3: (a) The pressure plume after 25 years of injection with an injection rate of 1 Mt/years. (b) The seabed uplift caused by poroelastic expansion of the Utsira Formation.

Fig. 3 shows the distribution of the pressure plume after 25 years of injection with a rate of 1 Mt/year. The plot shows the pressure change, which is the difference from the initial hydrostatic pressure. The plume does not extend beyond the Southern part of the aquifer. That is also why the entire aquifer is not a part of the model.

It is possible to make two estimates of pore fluid volumes. The first is the additional storage space created by the dilation of the aquifer. The second is the fluid volume stored due to compression. The space for fluid created by expansion of the aquifer is $V_{uplift}=\phi l_x l_y dh$. A coarse estimate is obtained by letting the lateral size of the pressure plume to be $l_x = 50$ km and $l_y = 50$ km, with an average uplift $dh = 4$ cm becomes $V_{uplift} = 9\times10^6$ m3 using $\phi= 0.35$. The volume of fluid compressed in the pressure plume is estimated to $V_{compres} = \phi c_f l_x l_y h dp$. Using c_f=0.45 1/GPa and $dp = 5\times10^4$ Pa gives that $V_{compres} = 5\times10^6$ m^3. These two estimates added together give the volume 14×10^6 m^3, which has at least the correct order of magnitude when compared with the total injected volume of 25×10^6 m^3. The estimates indicate that the expansion of the sand could have an important contribution to the storage volume.

Fig. 4a shows the uplift evolution in the injection cell for the four different injection rates. The injection rate is increased in steps of a factor 10. We notice that the uplift evolution is proportional to the injection rate. The uplift as a function of time is the same, except that it increases with the same factor as the injection rate. This is as expected from Theis solution for fluid pressure, which applies for fluid injection with a constant rate into a flat and unbounded aquifer with a constant thickness and a constant permeability [13]. Theis solution gives that the transient pressure in the aquifer is proportional to the injection rate.

The seabed uplift follows the fluid pressure, and an increase in the fluid pressure by a factor of 10 gives an increase in the seabed uplift with almost the same factor of 10. The simple scaling with respect to a constant injection rate is useful for making pressure and uplift predictions for different injection rates.

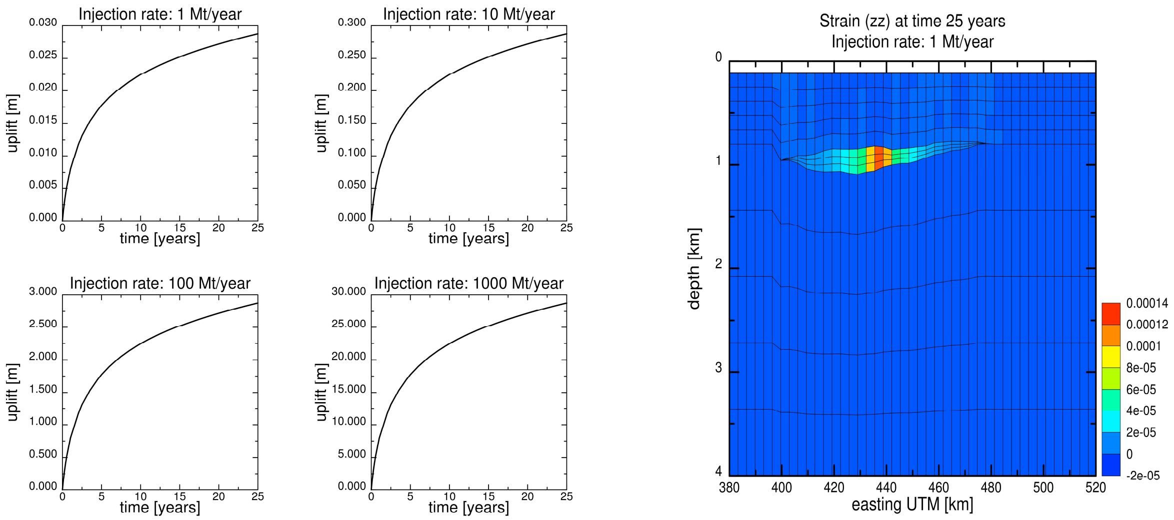

Fig. 4: (a) The seabed uplift above the injection element for different injection ratios. (b) The distribution of strain in a vertical cross section that goes through the injection element.

Fig. 4b shows the strain in a vertical cross section in the North-South direction that goes through the well element. It is seen that all the dilation that appears as seabed uplift is due to expansion of the aquifer. That is because the fluid pressure is increasing in the aquifer, but there is almost no pressure increase in the nearly impermeable overburden and underburden.

The simple 1D estimate of the seabed uplift, which assumes that nearly all the uplift is directly related to dilation of the sand, seems to work well. From Equation (7) using E = 0.25 GPa, $\nu = 0.25$, $p = 5\times10^4$ Pa and h = 250 m gives 4 cm vertical aquifer expansion and seabed uplift. The estimate is more than the approximately 3 cm uplift from the poroelastic simulation, because the estimate assumes 1D vertical deformation.

6. Importance of the elastic properties of the Utsira sand and the Nordland shale

The poroelastic simulations and the analytical estimates show that dilation of the Utsira sand and the seabed uplift is proportional to the aquifer overpressure and inverse proportional to Young's modulus. The fluid overpressure is mostly controlled by the injection rate and the permeability field. The uncertain issue with the uplift is the Young's modulus for the sand during dilation and the limits of the poroelastic model. Large-scale storage of CO_2 can require injection rates of 10 Mt/year to 100 Mt/year. Injection rates that are considerably larger than the current rate of 1 Mt/year lead to an uplift that is proportional to the injection rate, assuming single-phase flow. The dilation of the Utsira Formation can therefore be considerably larger. This simple model shows that the main impact of fluid injection is from the expansion of the Utsira sand. The soft Nordland shale seams to adapt to the dilation of the Utsira sand, when the expansion is smooth over large areas, as in the current model. The Nordland shale is soft because it is not fully lithified from the top to base. However, there may be isolated and impermeable spots inside the Utsira Formation, which will not have pressure build-up and expansion. The boundaries of such areas could be places that may undergo shear deformations and fracturing.

7. Conclusions

The Utsira Formation is a sand aquifer, which is a candidate for large-scale CO_2 storage, because of its high porosity and permeability. We have studied the geomechanical deformations of the Utsira Formation with a single-phase model using injection rates from 1 Mt/year in steps of factor 10 up to 1000 Mt/year. We found that pressure plume for different injection rates scales with the injection rate. The pressure profile in time and space is the same when it is scaled with the injection rate. This result, which follows from Theis solution for the radial flow around a well, is useful for estimating the level of pressure build-up for different injection rates. The pressure build up from the injection of 1 Mt/year over 25 years is in the range of 2×10^4 Pa to 4×10^4 Pa, except in the immediate vicinity of the injection well, because of the high permeability and the thickness of the formation. The associated dilation of the Utsira Formation is in the range of 5 mm to 10 mm. The modelling suggests that these results become multiplied by a factor of 10 if the injection rate increases with the same rate. A particular uncertainty with the model is the Young's modulus of the sand of the Utsira Formation and the limits of the poroelasticty. A Young's modulus that is less than the current choice would lead to more dilation of the formation and more seabed uplift, and at the same time the limits of poroelasticity will be reached earlier.

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