Evolution of poroviscoelastic properties of silica-rich rock after CO₂ injection

Kiseok Kim¹, Roman Y. Makhnenko^{1,*}

¹Department of Civil and Environmental Engineering, University of Illinois at Urbana-Champaign, Urbana, IL 61801, USA

Abstract. Injection of CO₂ into the subsurface requires consideration of the poromechanical behavior of reservoir rock saturated with aqueous fluid. The material response is usually assumed to be elastic, to avoid consideration of induced seismicity, or viscoelastic, if long-term deformations are needed to be taken into the account. Both elastic and viscous behavior may be influenced by the chemical reactions that are caused by the acidic mixture formed as high-pressure CO₂ enters the pore space saturated with aqueous fluid. In this study, we conduct laboratory experiments on a fluid-saturated porous rock - Berea sandstone, and evaluate its poromechanical properties. Subsequently, the specimens are treated with liquid CO₂ for 21 days and the corresponding variations in their properties are determined. The constitutive model considering the elastic time-dependent behavior of porous rock is validated by comparing the measured and predicted specimen deformation. Presented data indicate that the effect of CO₂ injection on the long-term response is more significant compared to the short-term response. It is suggested for the constitutive models that predict long-term reservoir behavior during CO₂ storage to include not only the poroelastic response and its change due to treatment, but also the time-dependent deformation and its evolution caused by the changes in chemistry of the pore fluid.

1 Introduction

The primary purpose of geologic carbon storage (GCS) is to inject large volumes of CO₂ into subsurface reservoirs sealed with low-permeable layers. Participating geological formations are saturated with the pre-existing aqueous fluid that affects the poromechanical behavior of the rock [1]. During the CO₂ injection, either in liquid or supercritical state, multiphysical processes (e.g., mechanical, thermal, hydraulic, and chemical interactions) may occur in the saturated reservoir as a result of overpressure, thermal stress, and chemical reactions caused by the high acidity of CO₂ and aqueous fluid mixture [2, 3]. It becomes essential to properly understand the effect of CO₂ injection on the mechanical behavior of reservoir rock and predict the associated deformations to evaluate the safety of the carbon storage operations [4].

The mechanical response of porous rock incorporates both elastic and inelastic behavior. Since the fundamental goal of GCS is to inject and store CO₂ safely, we concentrate mainly on the elastic response in order to avoid inelastic deformation that may cause damage and induce seismicity. Moreover, considering the permanent time scale of carbon storage (up to thousands of years), the elastic response of reservoir rock must be examined for both short-term (poroelasticity) and long-term deformation (poroviscoelasticity) [5, 6]. The latter one is characterized as the elastic time-dependent behavior of

rock where the pore pressure diffusion is coupled with the matrix deformation. It can be explicitly derived from Biot's infinitesimal strain theory [7, 8] and describes viscous response within the elastic limit [9]. Previous studies on the fluid-saturated reservoir rock showed that the effect of CO₂ injection on its poroelastic response depends on the mineralogical composition. For calcite-rich rock, laboratory experiments demonstrated that dissolution occurs due to the formation of carbonic acid, which increases the porosity and permeability and reduces the strength of rock [10, 11]. However, for silica-rich rock, it is often manifested that the mechanical and flow properties are less affected by CO₂ treatment due to the weaker reactivity of quartz [12, 13]. These findings also confirmed that sandstone formations are the most suitable candidates for CO₂ storage [14].

Despite the existing studies on the poromechanical response of reservoir rock, there is a lack of consistent understanding of the effect of CO₂ treatment on both poroelastic and poroviscoelastic behavior of silica-rich rock. In this study, we select Berea sandstone as the representative reservoir material. A constitutive model is adopted to include both short- and long-term deformation of a fluid-saturated rock. Laboratory techniques are developed to characterize the mechanical and flow properties of the sandstone before and after liquid CO₂ treatment. Consequently, the constitutive model is verified by two independent experimental approaches.

* Corresponding author: romanmax@illinois.edu

2 Background

We consider a representative elementary volume of a fluid-saturated rock with porosity ϕ subjected to mechanical loading expressed through the stress tensor σ_{ij} . Total mean stress $P = \sigma_{ij}/3 = (\sigma_1 + \sigma_2 + \sigma_3)/3$ can be disintegrated into two variables: Terzaghi effective mean stress $P' = P - p^f$ and pore fluid pressure p^f . Variations in the dynamic parameters σ_{ij} and p^f produce mechanical deformation and pore fluid volume change, which can be expressed through the kinematic parameters: strain tensor ε_{ij} and increment of fluid content ζ . The bulk response of the porous media can be characterized through the volume strain $\varepsilon = \varepsilon_{kk} = \varepsilon_{11} + \varepsilon_{22} + \varepsilon_{33}$. The increment of fluid content is determined as $\zeta = -dm^f / p^f$, where dm^f is the change of the fluid mass per unit volume and p^f is fluid density [15]. The sign convention is compression positive, *i.e.*, the decrease in specimen volume and the loss of the pore fluid result in positive values of ε and ζ , respectively.

Under elastic and isotropic loading conditions, the kinematic and dynamic variables can be related to each other by introducing the constitutive equations first suggested by Biot [7]. Biot 3D consolidation theory can also be expanded to consider the time-dependent behavior by adopting Maxwell's viscous strain term within the elastic range [5, 6]. Consequently, the volume strain rate can be decomposed into elastic and viscoelastic parts (Equation 1) and expressed through the increments of mean stress and pore pressure and the poroviscoelastic parameters (Equation 2).

$$\frac{d\varepsilon}{dt} = \frac{d\varepsilon_{elastic}}{dt} + \frac{d\varepsilon_{viscous}}{dt} \quad (1)$$

$$\frac{d\varepsilon}{dt} = \frac{1}{K} \frac{d(P - \alpha p^f)}{dt} + \frac{P - p^f}{(1 - \phi)\eta_\phi} \quad (2)$$

The constitutive equation for the increment of fluid content ζ can be written as

$$\frac{d\zeta}{dt} = \frac{\alpha}{K} \left(\frac{dP}{dt} - \frac{1}{B} \frac{dp^f}{dt} \right) + \frac{P - p^f}{(1 - \phi)\eta_\phi} \quad (3)$$

The poroviscoelastic parameters employed in the constitutive equations are explicitly defined below.

The bulk modulus characterizes the volume compressibility of a porous material, where it can be defined under two limiting boundary conditions: drained (K) and undrained (K_u) [15]. The drained boundary condition is described by no change in the pore fluid pressure: $\Delta p^f = 0$, while the undrained condition implies that fluid cannot enter or exit the porous material: $\zeta = 0$. Drained and undrained bulk moduli can be expressed in terms of the corresponding Young's moduli (E and E_u) and Poisson's ratios (ν and ν_u).

$$K = \frac{\Delta P}{\Delta \varepsilon} \Big|_{\Delta p^f = 0} = \frac{E}{3(1 - 2\nu)} \quad (4)$$

$$K_u = \frac{\Delta P}{\Delta \varepsilon} \Big|_{\zeta = 0} = \frac{E_u}{3(1 - 2\nu_u)} \quad (5)$$

Under the drained condition, Biot coefficient α is defined as the ratio of the fluid volume expelled from the specimen to the change in its bulk volume (Equation 6). It can also be expressed through the drained bulk modulus K and theunjacketed bulk modulus K_s' , which characterizes the volume deformation of the specimen tested under theunjacketed condition: $\Delta P = \Delta p^f$ [15].

$$\alpha = \frac{\Delta \zeta}{\Delta \varepsilon} \Big|_{\Delta p^f = 0} = 1 - \frac{K}{K_s'} \quad (6)$$

Under the undrained condition, the Skempton's B coefficient [16] is introduced as the ratio of the induced pore pressure variation to the change in total mean stress (Equation 7). The Skempton's B coefficient provides the degree of coupling between the solid and fluid responses and allows to determine whether full saturation has been reached [17].

$$B = \frac{\Delta p^f}{\Delta P} \Big|_{\zeta = 0} = \frac{K_u - K}{\alpha K} \quad (7)$$

Finally, the effective bulk viscosity η_ϕ [Pa·s] characterizes a tendency of rock to creep in the elastic range, with its higher values corresponding to slower creep rates.

3 Experimental procedure

3.1 Material

Berea sandstone, quarried in Berea, Ohio is selected as the representative reservoir rock. It is composed mainly of sub-rounded to rounded quartz grains (85%) with the average size of 0.2 mm and includes a fraction of clay particles, such as muscovite/illite (6%) and kaolinite (3%), as well as K-feldspar (2%) and albite (1%). The interconnected porosity is measured by the vacuum saturation method to be 0.203. The material exhibits slight elastic anisotropy (5-7%) due to the existence of bedding planes. The onset of inelastic response that induces significant microseismicity is characterized by the deviatoric loading above 70% of the material strength, which is reported to be 30-32 MPa under the uniaxial compression conditions [18]. The strength characteristics measured under drained (or dry) and undrained conditions are the same given the effect of the effective mean stress on rock failure being considered [19].

Previous studies on this rock in the pristine state showed that the effect of CO₂ injection on the poromechanical properties is negligible [20]. Therefore, damaged specimens are prepared by the thermal treatment - one of the most reproducible and consistent methods to induce controlled microcracks in the material due to the anisotropic thermal expansion of different

minerals [21]. Pristine Berea sandstone specimens are heat treated at 300°C for 72 hours and then gradually cooled down. Damaged rock appeared to have slightly larger porosity $\phi = 0.212$.

3.2 Saturation and CO₂ treatment

CO₂ treatment of the rock specimens is performed in the core flooding device [22]. Cylindrical specimens (50 mm in diameter and 100 mm in length) are installed in a viton membrane that isolates the confining pressure fluid from the pore fluid. Silicon hydraulic oil is used to apply the confining pressure controlled by a high-pressure pump (SANCHEZ, France) with a capacity of 70 MPa (50 kPa accuracy). For injection of the pore fluid, two syringe pumps (ISCO, USA) with a capacity of 25.9 MPa (25 kPa accuracy) are installed to control the input and output pressures. Moreover, another syringe pump (ISCO, USA) with a capacity of 51.7 MPa (50 kPa accuracy) is set at the input for CO₂ injection. De-ionized water is utilized as the pore fluid in order to focus only on the chemical effect of CO₂ injection and exclude the reactions that in-situ brines might cause.

Before the injection of CO₂, full water saturation is achieved by the back-pressure technique. After flushing the specimen with water, the back (pore) pressure in the system is continuously increased and the Skempton's B coefficient is measured at each increment of the pore pressure, while the effective mean stress is controlled to be constant [17]. Before reaching full saturation, measured B values increase with the pore pressure that reduces the size of the air bubbles in the pores before completely dissolving them. Subsequently, as full saturation is achieved, constant B values are measured and Bishop's [23] correction factor C_{cor} is considered to include the compressibility of the inner pore lines and the pore pressure measuring system (Equation 8). For the core flooding device, the correction factor is evaluated to be $C_{cor} \sim 0.5 \times 10^{-2}$ and it does not affect the accuracy of the B measurements (± 0.005).

$$B = \frac{1}{\left(\frac{\Delta p^f}{\Delta P}\right)^{-1} - C_{cor}} \quad (8)$$

The axial loading in the core flooding device is applied through a passive kinematic restraint – the axial deformation of the specimens is restricted by the fixed steel platens. Calculation of the total mean stress in this case requires knowledge of the Poisson's ratio under drained (for flow measurements) and undrained (for Skempton's B coefficient measurements) boundary conditions. The change in total mean stress is $\Delta P = (2+2\nu)\Delta\sigma_{lat}/3$ for the drained condition and $\Delta P = (2+2\nu_u)\Delta\sigma_{lat}/3$ for the undrained case. Dry Poisson's ratio is measured in the uniaxial compression test [18] and the undrained Poisson's ratio ν_u is calculated from Equation (9). Here, theunjacketed bulk modulus is taken as $K_s' = 30$ GPa [24].

$$\nu_u = \frac{3\nu + \alpha B(1-2\nu)}{3 - \alpha B(1-2\nu)} \quad (9)$$

The injection of CO₂ is conducted in liquid state (7 MPa) at room temperature (22°C) after reaching full water saturation at the effective mean stress of 5 MPa. The experimental boundary condition is controlled to be undrained at the output, while CO₂ is only injected through the input. After injecting 40-50 mL of liquid CO₂, the valve for the input is closed. It is observed that the pore pressure has a tendency to drop to the boundary pressure of liquid and gaseous state of CO₂ (6.2 MPa). Thus, additional liquid CO₂ is injected daily for 21 days to resume the pressure at liquid state. Shi et al. [25] suggested that a longer CO₂ treatment could enhance its effect on rock porosity by comparing the treatment periods of one and two weeks. Based on our experience with a limestone [22], three weeks are selected as the realizable CO₂ treatment period for the lab testing. However, we recognize that longer treatments can make the CO₂ injection effect more pronounced.

After the treatment, the Skempton's B coefficient is measured for the specimen that contains a mixture of CO₂ and water, in order to determine the degree of CO₂ saturation. Subsequently, the mixed pore fluid is completely flushed with water and the water saturation procedure is repeated to measure the change in B values for CO₂ treated damaged Berea sandstone. Detailed description of the experimental procedure is provided in [23].

In addition, steady state flow tests are performed on water-saturated damaged and CO₂ treated damaged sandstone with the differential fluid pressure $\Delta p = 70$ kPa. Darcy permeability k is calculated from measurements of the outflow ΔV (m³) over time increment Δt (s), as well as the knowledge of the dynamic fluid viscosity μ (≈ 0.001 Pa·s for water at room temperature), length of specimen L (m), and the cross-sectional area perpendicular to the flow direction A (m²).

$$k = \frac{\Delta V \mu L}{\Delta t \Delta p A} \quad (10)$$

3.3 Triaxial compression test

Measurements of the poroelastic properties of rock are conducted on the same specimens that are utilized in the core flooding tests by performing axisymmetric compression in a triaxial cell with the capacity of 3.5 MPa (GDS instruments, UK). The axial load is applied with the 50 kN load frame, while confining pressure and input/output pore pressures are controlled by the pressure/volume control pumps with 4.0 MPa capacity. To monitor the pore pressure during the undrained response, two pressure transducers are installed at the input and output. The axial strain is calculated from the average of the deformation measurements on two axial LVDTs attached to the opposite sides of the specimen. Full saturation is achieved before the compression test by the back-pressure saturation method performed at a constant $P' = 2$ MPa. After reaching saturation, axial compression tests are conducted in the elastic

deformation range (up to 10 MPa deviatoric load). Given high permeability of the sandstone, the loading rate of 1 micron/s is enough to guarantee the pore pressure equilibration in the tested specimens. Loading-unloading tests are conducted under drained and undrained conditions allowing the calculation of the drained E and undrained E_u Young's moduli.

The poroviscoelastic behavior of rock can be assessed under the undrained boundary condition. Before reaching full saturation, the pore pressure in the specimen decreases with time due to the dissolution of air bubbles in the pore fluid. After full saturation is reached, a pore pressure buildup is observed under undrained and constant total mean stress conditions ($\zeta = 0$, $dP/dt = 0$), according to Equation (3). This provides an "indirect method" to assess the viscoelastic behavior of rock and measurements of the pore pressure increase rate dp/dt , along with the knowledge of the poroelastic parameters such as B , K , and α allow determination of the effective bulk viscosity η_ϕ [6].

$$\eta_\phi = \frac{BK}{\alpha(1-\phi)} \frac{P-p^f}{dp^f/dt} \quad (11)$$

From the measurements of specimen deformation during the time-dependent response, the constitutive model can be validated using Equation (2).

4 Results

4.1 Skempton's B coefficient and permeability

The Skempton's B coefficient values are measured for both damaged and CO₂ treated damaged Berea sandstone specimens and found to be decreasing with the increase in the effective mean stress (Figure 1).

Fig. 1. The Skempton's B coefficient for water-saturated damaged, water-saturated CO₂ treated damaged, and partially CO₂-saturated (after treatment) Berea sandstone as functions of the effective mean stress.

After the CO₂ treatment, the Skempton's B coefficient for the sandstone that contains a mixture of CO₂ and water is measured to be 0.04, and with the knowledge of the rock's poroelastic properties, the degree of CO₂ saturation is calculated to be 0.68-0.75 [22]. When the treated rock is re-saturated with pure water, a decrease from the original B values is reported. This decrease of B could be explained by a potential decrease in the undrained bulk modulus or increase in the drained bulk modulus of rock due to the CO₂ treatment (Equation 7) – it would require the direct measurements of K_u and ν_u to properly address this issue. In addition, the CO₂ treatment results in the increase of the sandstone's porosity, from 0.212 to 0.226, and permeability, from $0.18 \cdot 10^{-12} \text{ m}^2$ to $0.30 \cdot 10^{-12} \text{ m}^2$. The results of the tests are summarized in Table 1.

4.2 Drained/Undrained response

Drained and undrained triaxial compression tests are conducted on the damaged and CO₂ treated damaged Berea sandstone specimens. The loading-unloading procedure is replicated to check the repeatability of the test, where two axial LVDTs and one radial LVDT measure the deformation during the experiment. The slope of the stress-strain curve increases until reaching a linear behavior, which allows the calculation of the Young's modulus. Depending on the boundary conditions (drained or undrained), E or E_u are reported (Figure 2). For the drained response, Young's modulus is 11.9 GPa for damaged and 11.1 GPa for CO₂ treated damaged specimens tested at the effective minimum principal stress of $\sigma_3' = 2 \text{ MPa}$. The undrained response indicates a small increase in the modulus compared to the drained condition, and E_u for damaged sandstone is slightly larger than the one for CO₂ treated damaged state, 12.4 GPa and 11.9 GPa, respectively. These results are consistent among two different sets of specimens. The experiment outcomes highlight the minor effect of CO₂ treatment on short-term poroelastic response of the silica-rich rock.

Table 1. Summary of poroviscoelastic properties of damaged and CO₂ treated damaged Berea sandstone (reported at $P^f = 2 \text{ MPa}$).

Parameter	Damaged sandstone	CO ₂ treated damaged sandstone
ϕ [-]	0.212	0.226
k [$\times 10^{-12} \text{ m}^2$]	0.17	0.30
B [-]	0.88	0.76
E [GPa]	11.9	11.1
E_u [GPa]	12.4	11.9
η_ϕ [$\times 10^{15} \text{ Pa} \cdot \text{s}$]	14	6.8
α [-] (calculated)	0.72	0.69
ν [-] (from [18])	0.26	0.30
K_s' [GPa] (from [24])	30	30
ν_u [-] (calculated)	0.40	0.39

Fig. 2. (a) Drained Young's modulus E and (b) undrained Young's modulus E_u measured in triaxial compression tests on water-saturated damaged and CO₂ treated damaged Berea sandstone at $\sigma'_3 = 2$ MPa.

4.3 Time-dependent deformation

Observations of the pore pressure buildup with time (over 6 hours) in fully saturated sandstone specimens tested at $P' \approx 2$ MPa are presented in Figure 3a. Knowledge of E and ν allows calculations of the drained bulk modulus $K = 8.3$ GPa and Biot coefficient $\alpha = 0.72$. Combined with the measurements of Skempton's B coefficient, these parameters allow the calculation of the bulk viscosity η_ϕ . It is observed that CO₂ treatment promotes sandstone's viscous compaction resulting in the decrease of bulk viscosity value by more than a half, from 1.4×10^{16} Pa·s to 6.8×10^{15} Pa·s. A similar effect is observed at $P' = 1$ MPa [18].

Furthermore, the measurements of volume strain along with the pore pressure buildup during the long-term response allow the validation of the constitutive model. The evolution of axial and lateral deformations with time indicate that the axial LVDTs are compressing, while the lateral LVDT is recording a small specimen expansion in the lateral direction (Figure

3b). Overall, the specimen is compacting and the volume strain ε as a function of time is shown in Figure 3c. The predicted volume strain from the constitutive model in Equation (2) is calculated using the poroviscoelastic parameters reported in this work. The comparison between prediction of the model and measured deformation shows good agreement given the issues with reporting volume strain with 10^{-5} accuracy (Figure 3c).

The effect of CO₂ injection not only on the poroelastic, but also on the viscoelastic properties needs to be studied for any potential reservoir rock. The bulk viscosity remains to be strongly effective stress dependent after the CO₂ treatment, but the CO₂ treated damaged Berea sandstone is noticeably more prone to time-dependent deformation in comparison to the pristine and damaged states [18]. Interestingly, previous studies on reservoir materials show, in general, little effect of CO₂ injection on induced creep in silica-rich rock, including Berea sandstone [11, 26]. At the same time, subcritical crack growth caused by atomic diffusion, dissolution, microplasticity, and stress corrosion, among others, is one of the major mechanisms involved in rock creep [27].

In general, creep strain rates are very sensitive to the environmental conditions, such as deviatoric and mean stresses, pore pressures, temperature, and pore fluid composition. Additionally, the effect is enhanced with increase of water saturation and pore pressure [6, 27, 28]. The presented experimental data indicates pore pressure buildup in both damaged and CO₂ treated specimens with the reduction of the effective stress globally and potential stress concentration on the asperities [6]. Also, the increase of the pore fluid acidity (by injecting liquid CO₂ into water-saturated sandstone) significantly promotes the long-term solid deformation comparing to the one recorded in the short-term. The results reported here reflect only the rock behavior after water imbibition that followed treatment with CO₂-rich fluid. Volume changes and fluid consumption/release during chemical reactions also induce porosity and fluid pressure evolution that affect pore and bulk deformation of the rock [29]. Proper characterization of this effect should consider the interplay between reaction and deformation and include measurements at different stages of CO₂ injection [30].

Furthermore, these observations could potentially explain the localization of some microseismic events that happened at different distances from the CO₂ injection well in Illinois Basin Decatur Project. The events were not predicted by the reservoir model and observations of near well overpressures, but have been recorded even a few months after the CO₂ plume moved away from the well [31]. Although, the mechanisms behind viscous behavior of rock need further experimental verification including measurements at microscales. Ultimately, the chemical and thermal effects of CO₂ injection on the short- and long-term rock behavior need to be explicitly included in a potential hydro-mechanical reservoir model.

Fig. 3. Time-dependent response of Berea sandstone observed under undrained and constant mean stress boundary conditions and expressed in terms of (a) pore pressure buildup with time at $P' = 2$ MP for damaged and CO₂ treated damaged specimens; (b) axial and lateral strain for CO₂ treated damaged specimen; (c) measured volume strain vs poroviscoelastic model prediction.

5 Conclusions

In this study, the experimental work on the effect of CO₂ injection on the poromechanical response of reservoir rock is presented. High permeable Berea sandstone (85% quartz by volume) is selected as the reservoir rock representative and the specimens are heat-damaged to increase the crack density of the material expecting an enhanced effect from CO₂ injection. After reaching full saturation with the back-pressure technique, the poromechanical properties of the sandstone are measured in the triaxial compression experiments. Subsequently, the specimens are treated with liquid CO₂ in the core flooding device for 21 days under the undrained boundary condition. Finally, the same poromechanical properties are measured for the specimens resaturated with only water for comparison with the untreated case.

A constitutive model that combines Biot poroelasticity with Maxwell's viscoelasticity is adopted to describe the time-dependent response of rock and experimental techniques are developed to measure the corresponding material properties. Changes in the rock's porosity, permeability, Skempton's B coefficient, and drained and undrained Young's moduli are reported. On top of that, the observation of the pore pressure buildup under the undrained condition allows the calculation of the effective bulk viscosity.

The experimental results demonstrate that for the elastic response, the effect of CO₂ treatment on the silica-rich rock is negligible: the Young's moduli under both drained and undrained conditions decrease insignificantly. At the same time, the bulk viscosity measured on specimens resaturated with water is considerably (more than twice) affected by the CO₂ treatment indicating the increased tendency of rock to creep. Measurements of the bulk deformation provide an independent characterization of the time-dependent rock response and allow validation of the constitutive model. Finally, it is suggested that the long-term behavior of the porous host rock needs to be taken into account for the reservoir model and needs to consider potential changes in the rock properties caused by CO₂ injection.

K. Kim's research was supported by Technip FMC Educational Fund Fellowship. R.Y. Makhnenko acknowledges the support from US DOE through CarbonSAFE Macon County Project DE-FE0029381.

References

1. J. Rutqvist, The geomechanics of CO₂ storage in deep sedimentary formations, *Geotech. Geol. Eng.* **30** (2012)
2. D.C. Thomas, S.M. Benson, *Carbon Dioxide Capture for Storage in Deep Geologic Formations* (Elsevier, Oxford, 2004)
3. Y. Le Guen, F. Renard, R. Hellmann, E. Brosse, M. Collombet, D. Tisserand, J.-P. Gratier, Enhanced deformation of limestone and sandstone in the presence of high P_{CO_2} fluids, *J. Geophys. Res.* **112** (2007)

4. W.R. Wawersik, J.W. Rudnicki, P. Dove, J. Harris, J.M. Logan, L. Pyrak-Nolte, M. Orr Jr, P.J. Ortoleva, F. Richter, N.R. Warpinski, J.L. Wilson, T-F. Wong, Terrestrial sequestration of CO₂: An assessment of research needs, *Adv. Geophys.* **43** (2001)
5. V.M. Yarushina, Y.Y. Podladchikov, (De) compaction of porous viscoelastoplastic media: model formulation, *J. Geophys. Res. Sol. Earth* **120** (2015)
6. R.Y. Makhnenko, Y.Y. Podladchikov, Experimental poroviscoelasticity of common sedimentary rocks, *J. Geophys. Res. Sol. Earth* **123** (2018)
7. M.A. Biot, General theory of three-dimensional consolidation, *J. Appl. Phys.* **12** (1941)
8. M.A. Biot, Theory of deformation of a porous viscoelastic anisotropic solid. *J. Appl. Phys* **27** (1956)
9. Y. Abousleiman, A. H.-D. Cheng, C. Jiang, J.-C. Roegiers, A micromechanically consistent poroviscoelasticity theory for rock mechanics applications. *Int. J. Rock Mech. Min. Sci. Geomech. Abstr.* **30** (1993)
10. J. Rohmer, A. Pluymakers, F. Renard, Mechano-chemical interactions in sedimentary rocks in the context of CO₂ storage: weak acid, weak effects?, *Earth-Sci. Rev.* **157** (2016)
11. V. Vilarrasa, R.Y. Makhnenko, J. Rutqvist, Field and laboratory studies of geomechanical response to the injection of CO₂, In: *Science of Carbon Storage in Deep Saline Formations: Process Coupling Across Time and Spatial Scales* (Elsevier, Amsterdam, 2009)
12. I.O. Ojala, The effect of CO₂ on the mechanical properties of reservoir and cap rock, *Energy Proc.* **4** (2011)
13. S. Hangx, A. van der Linden, F. Marcelis, A. Bauer, The effect of CO₂ on the mechanical properties of the Captain sandstone: geological storage of CO₂ at the Goldeneye field (UK), *Int. J. Greenhouse Gas Control* **19** (2013)
14. B. Metz, O. Davidson, H. de Coninck, M. Loos, L. Meyer, *IPCC Special Report on Carbon Dioxide Capture and Storage* (Cambridge University Press, Cambridge, 2005)
15. J.R. Rice, M.P. Cleary, Some basic stress diffusion solutions for fluid-saturated elastic porous media with compressible constituents, *Rev. Geophys. Space. Phys.* **14** (1976)
16. A. Skempton, The pore-pressure coefficients A and B, *Géotechnique* **4** (1954)
17. R.Y. Makhnenko, J.F. Labuz, Elastic and inelastic deformation of fluid-saturated rock, *Phil. Trans. R. Soc. A.* **374** (2016)
18. A. Tarokh, R.Y. Makhnenko, K. Kim, X. Zhu, J. Popovics, B. Segvic, D. Sweet, Influence of CO₂ injection on the poromechanical response of Berea sandstone, *Int. J. Greenhouse Gas Control* **95** (2020)
19. R.Y. Makhnenko, J.F. Labuz, Dilatant hardening of fluid-saturated sandstone, *J. Geophys. Res. Sol. Earth* **120** (2015)
20. V. Vilarrasa, R.Y. Makhnenko, Hydromechanical aspects of CO₂ breakthrough into clay-rich caprock, *Energ. Proc.* **125** (2017)
21. L. Biolzi, J.F. Labuz, G. Muciaccia, A problem of scaling in fracture of damaged rock, *Int. J. Rock. Mech. Min. Sci.* **48** (2011)
22. K. Kim, V. Vilarrasa, R.Y. Makhnenko, CO₂ injection effect on geomechanical and flow properties of calcite-rich reservoirs, *Fluids* **3** (2018)
23. A.W. Bishop, The influence of system compressibility on the observed pore-pressure response to an undrained change in stress in saturated rock, *Géotechnique* **12** (1976)
24. A. Tarokh, R.Y. Makhnenko, Remarks on the solid and bulk responses of fluid-filled porous rock, *Geophysics* **84** (2019)
25. Z. Shi, L. Sun, I. Haljasmaa, W. Harbert, S. Sanguinito, M. Tkach, A. Goodman, T.T. Tsotsis, K. Jessen, Impact of Brine/CO₂ exposure on the transport and mechanical properties of the Mt Simon sandstone, *J. Petro. Sci. Eng.* **177** (2019)
26. Y. Oikawa, T. Takehara, T. Tosha, Effect of CO₂ injection on mechanical properties of Berea sandstone, *Proceedings of 42nd US Rock Mechanics Symposium and 2nd US-Canada Rock Mechanics Symposium, San Francisco, CA* (2008)
27. N. Brantut, M.J. Heap, P.G. Meredith, P. Baud, Time-dependent cracking and brittle creep in crustal rocks: A review, *J. Struct. Geol.* **52** (2013)
28. Y. Bernabe, D.T. Fryer, R.M. Shively, Experimental observations of the elastic and inelastic behavior of porous sandstones, *Geophys. J. Int.* **117** (1994)
29. A. Putnis, Mineral replacement reactions, *Rev. Mineral. Geochem.* **70** (2009)
30. S. Omlin, B. Malvoisin, Y.Y. Podladchikov, Pore fluid extraction by reactive solitary waves in 3-D, *Geophys. Res. Lett.*, **44** (2017)
31. R.A. Bauer, R. Will, S. Greenberg, S.G. Whittaker, Illinois Basin-Decatur project. In: *Geophysics and Geosequestration* (Cambridge University Press, Cambridge, 2019).