Geologic carbon storage is unlikely to trigger large earthquakes and reactivate faults through which CO_2 could leak

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Zoback and Gorelick [(2012) *Proc Natl Acad Sci USA* 109(26):10164–10168] have claimed that geologic carbon storage in deep saline formations is very likely to trigger large induced seismicity, which may damage the caprock and ruin the objective of keeping CO_2 stored deep underground. We argue that felt induced earthquakes due to geologic CO_2 storage are unlikely because (*i*) sedimentary formations, which are softer than the crystalline basement, are rarely critically stressed; (*ii*) the least stable situation occurs at the beginning of injection, which makes it easy to control; (*iii*) CO_2 dissolution into brine may help in reducing overpressure; and (*iv*) CO_2 will not flow across the caprock because of capillarity, but brine will, which will reduce overpressure further. The latter two mechanisms ensure that overpressures caused by CO_2 injection will dissipate in a moderate time after injection stops, hindering the occurrence of postinjection induced seismicity. Furthermore, even if microseismicity were induced, CO_2 leakage through fault reactivation would be unlikely because the high clay content of caprocks ensures a reduced permeability and increased entry pressure along the localized deformation zone. For these reasons, we contend that properly sited and managed geologic carbon storage in deep saline formations remains a safe option to mitigate anthropogenic climate change.

carbon sequestration | induced seismicity | overpressure | climate change | CO_2 leakage

Zoback and Gorelick (1) claim that geologic carbon storage in deep saline formations is very likely to trigger induced seismicity capable of damaging the caprock, which could ruin the objective of keeping CO_2 stored deep underground. According to them, the main reason for this is that overpressure will be excessively high and failure conditions will be reached because the upper crust is critically stressed, i.e., close to failure. It is true that an excessive overpressure may induce microseismicity and even felt seismicity (2). It is also true that a felt seismic event could stop CO_2 sequestration projects, as happened with the geothermal project Basel Deep Heat Mining Project in Switzerland (3). However, there is no evidence from the existing CO_2 storage projects that CO_2 has the potential of easily inducing large earthquakes (4).

No felt seismic event has been reported to date at either pilot or industrial CO_2 storage projects (4–8). Even at In Salah, Algeria, where a huge overpressure was induced, no felt seismic event has been induced (7, 9). CO_2 storage in depleted gas fields has also been proven to be a safe option both at Otway, Australia (6) and at Lacq, France (5, 8). Actually, CO_2 storage operates under conditions similar to natural gas storage, which has not induced felt seismicity for decades (10–12). The recent induced seismic events at Castor, Spain (13) appears to be the only exception. However, too little is known about this site to extract any lesson. In fact, the very ignorance about what happened at Castor suggests that site understanding and management may be the critical issues.

We argue that large induced earthquakes related to CO_2 injection in deep saline formations are unlikely because (*i*) sedimentary formations are rarely critically stressed; (*ii*) the least stable conditions occur at the beginning of injection; (*iii*) CO_2 may dissolve at a significant rate, reducing overpressure; and (*iv*) brine will flow across the caprock, lowering overpressure in the reservoir. For these reasons we believe that geologic carbon storage in deep saline formations remains a safe option for mitigating climate change.

It Is Not True That the Whole Upper Crust Is Critically Stressed

It is generally accepted that the crystalline basement is critically stressed at some depth intervals (14–16). However, CO_2 will be injected in shallow (1–3 km deep) sedimentary formations, which are much softer than the brittle and stiff crystalline basement. As such, stress criticality, i.e., mobilized frictional coefficients, μ, in the range of 0.6–1.0 (17), is not usually observed at shallow depths within sedimentary formations (16, 18–21). We have compiled effective stress data of sedimentary formations and they fall within values of mobilized frictional coefficients around 0.4, i.e., the actual deviatoric stress is lower than the critical one (Fig. 1). This value is moderately low compared with the frictional coefficients around 0.6–0.8 of the critically stressed crystalline basement. In particular, the mobilized friction coefficients of sedimentary rocks where CO_2 is being, has been or is planned to be injected is always lower than the critical value of 0.6. This means that there is a wide margin before CO_2 injection might induce failure conditions and therefore, trigger a seismic event.

To illustrate that sedimentary formations are unlikely to be critically stressed, we have built a simple model of the upper

Significance

Geologic carbon storage remains a safe option to mitigate anthropogenic climate change. Properly sited and managed storage sites are unlikely to induce felt seismicity because (*i*) sedimentary formations, which are softer than the crystalline basement, are rarely critically stressed; (*ii*) the least stable situation occurs at the beginning of injection, which makes it easy to control; (*iii*) CO_2 will dissolve into brine at a significant rate, reducing overpressure; and (*iv*) CO_2 will not flow across the caprock because of capillarity, but brine will, which will reduce overpressure further. Furthermore, CO_2 leakage through fault reactivation is unlikely because the high clay content of caprocks ensures a reduced permeability and increased entry pressure along localized deformation zones.

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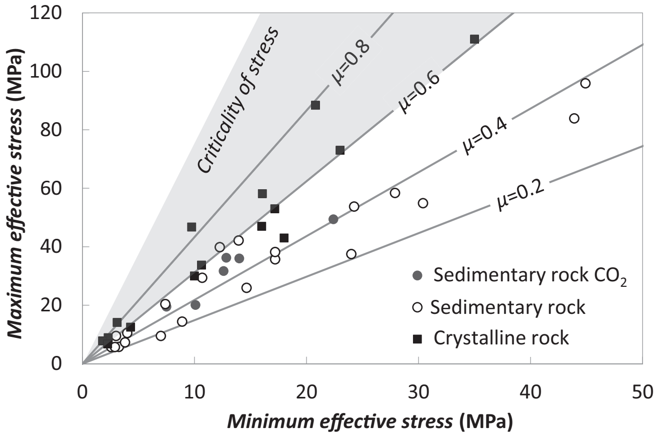

Fig. 1. Maximum versus minimum effective stress measured in wellbores at depth in both crystalline (black squares) and sedimentary rocks (hollow circles). Sedimentary rocks where CO_2 is being, has been or is planned to be injected are marked with black circles. The lines corresponding to several mobilized friction coefficients, μ, are included as a reference. Note that whereas crystalline rocks are critically stressed, sedimentary rocks are usually not.

crust in a typical intraplate setting. The shallowest 2.5 km represent sedimentary rocks and the rest, down to 16 km deep, is crystalline rock. The sedimentary rock is softer than the crystalline rock (see *SI Text* for details). The stress state is initially isotropic, i.e., the mobilized friction coefficient equals 0. We impose a typical intraplate strain rate of 10^{-17} s^{-1} (22). As a result, the crystalline rock becomes critically stressed ($\mu = 0.6$) after 6 Myr. However, the sedimentary rock remains less stressed ($\mu = 0.4$) because of its lower stiffness (Fig. 2). This numerical result is consistent with the low frequency of intraplate seismic events and with the effective stress data compiled in Fig. 1 that evidences that the whole upper crust is not critically stressed. In particular, the shallow 'soft' sedimentary formations are far from critically stressed.

Some support for this simple model results from the fact that it yields the maximum mobilized frictional coefficient at a depth between 5 and 6 km (Fig. 2). This means that shallow earthquakes are most likely to occur in the crystalline basement at this depth. Interestingly, this depth of maximum occurrence of earthquakes is consistent with observations of frequency-depth distribution of earthquakes in continental intraplate regions such as Haicheng, China; Thessaloniki, Greece; Hansel Valley, Utah; Pocatello Valley, Idaho; Wasatch, Utah; Coso geothermal field, California (23) and Galicia, Spain (24); and in the plate boundary of the San Andreas Fault, California (23, 25, 26).

The evidence that sedimentary rocks are not critically stressed (Figs. 1 and 2) appears to contradict the large magnitude earthquakes induced by wastewater injection in sedimentary formations in 2011 at Oklahoma, Ohio and Arkansas. These earthquakes have been used as an argument against geologic carbon storage (1). However, the earthquakes were induced in the critically stressed crystalline basement and not in the sedimentary formations where wastewater was injected. Wastewater was injected into the basal aquifer, which led to the pressurization of faults in the crystalline basement (27–29). In the case of the earthquakes of Guy and Greenbrier, Arkansas, wastewater was injected into the Ozark aquifer (3 km deep), which is placed right above the crystalline basement. Wastewater leaked into a deeper fault, inducing four earthquakes of magnitude $M > 3.9$, with a maximum magnitude of 4.7, at around 6 km deep (30). This finding highlights (i) the need for proper characterization and (ii) the importance of a seal below the storage formation, to isolate the critically stressed crystalline basement from CO_2 injection in sedimentary formations.

It has been conjectured that if an induced earthquake similar to those triggered by wastewater injection in 2011 occurred in a CO_2 storage site, fault reactivation would lead to CO_2 leakage (1). We contend that close analysis of fault zone architecture reveals that CO_2 will not easily penetrate into the portions of the fault contained within shale rocks (31). Fault permeability, which is highly variable in reservoir-caprock sequences (32, 33), decreases several orders of magnitude for increasing clay content, leading to a much lower permeability in the caprocks than in the reservoirs (34, 35). Rocks with low clay content, like reservoirs, tend to fracture, increasing the width of the damaged zone and usually increasing permeability in response to shear (34). However, clay-rich rocks, like caprocks, tend to concentrate shearing in the fault core, which reduces the grain size by friction, thus reducing fault permeability (34). Therefore, shear slip will usually increase fault permeability in the reservoir, but decrease it in the caprock, increasing the permeability contrast in the vertical direction (31, 36). Indeed, numerical simulations show that CO_2 leakage is negligible when accounting for this heterogeneity in permeability in the vertical direction within faults undergoing shear displacement (37). Even assuming constant permeability in the vertical direction within the fault, no correlation has been found between shear slip and CO_2 leakage (38). Furthermore, capillary entry pressure increases with both clay content and reduced pore size, which is what ultimately hinders CO_2 penetration into the fault (39).

Overpressure Evolution

The evolution of overpressure induced by CO_2 injection is significantly different from that of water (or wastewater) injection. Water injection at a constant mass flow rate through a vertical well into an extensive (infinite) confined formation induces an overpressure that increases linearly with the logarithm of time (40). Therefore, overpressure will become large for very long injection times. This was the case at Paradox Valley, Colorado, where overpressure increased more than 16 MPa over a decade of injecting a constant volume of saline water (29). On the other hand, the low viscosity of CO_2 implies that overpressure caused by CO_2 injection peaks at the beginning of injection and drops

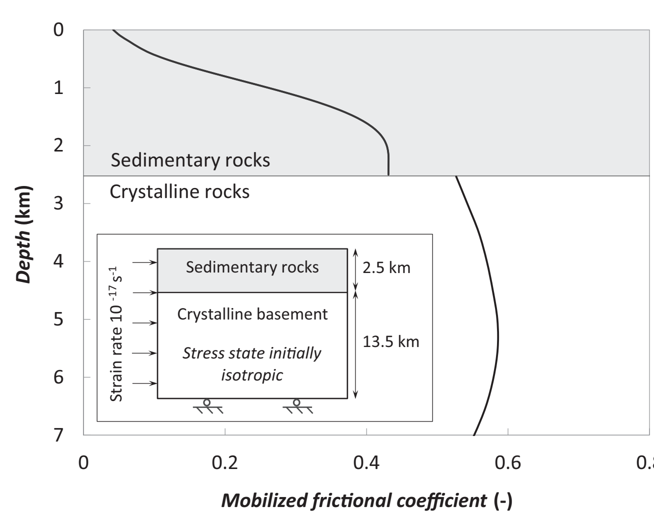

Fig. 2. Mobilized friction coefficient as a function of depth after 6 Myr of applying a strain rate typical of plate tectonics (10^{-17} s^{-1}) in the upper crust considering that the stress field is initially isotropic (see inlet for a sketch of the model). Note that whereas the crystalline basement becomes critically stressed, the sedimentary rocks remain far from being critically stressed.

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slightly afterward (41–48) (see inlet Fig. 3). This difference makes CO_2 injection particularly interesting because the most critical state occurs at the beginning of injection (41, 49) (Fig. 3). This initial critical situation is illustrated by what happened at Weyburn, Canada, where around 200 microseismic events were induced at the beginning of CO_2 injection, but no more events were measured afterward (50). In fact, initial microseismicity may be reduced by progressively increasing the CO_2 injection rate to avoid the peak in overpressure at the beginning of injection.

Storage formations need not be extensive or fully confined, as assumed in the above discussion. Overpressure induced by CO_2 injection may increase over time if the pressure perturbation cone reaches a flow barrier, such as a low-permeability fault. In such case, or in a compartmentalized reservoir (51), the reservoir storage capacity could be limited by the maximum sustainable injection pressure, defined so as to avoid induced seismicity (52). Fluid pressure must be monitored to identify the presence of flow barriers and to adopt mitigation measures to avoid an excessive overpressure that could lead to induced seismicity and make the operation uneconomical. Nevertheless, the reservoir will never be totally closed and overpressure will dissipate with time, helping to maintain fault stability and hinder postinjection induced earthquakes.

Overpressure will extend tens to hundreds of km for the time scales of CO_2 storage projects, i.e., 30–50 y (53). At these spatial scales, the effective caprock permeability can be two orders of magnitude higher than that of the core scale due to the existence of discontinuities (54). Thus, caprock permeability can become relatively high, i.e., up to 10^{-16} m^2 (55). Because the caprock seals brine by permeability, but it seals CO_2 by capillarity, brine, but not CO_2, can flow through the caprock (56). Fig. 4 shows that overpressure can be significantly lowered for relatively permeable caprocks, which would reduce the risk of inducing seismic events through fault reactivation due to the lower overpressure. Furthermore, the lateral extent of the pressure perturbation cone will also be significantly reduced (Fig. 4), which increases the reservoir storage capacity (57) and reduces the number of fractures and faults that will undergo stability changes. Indeed, a steady state could be reached in which the flow rate of brine flowing through the caprock equals the injected flow rate. Using leaky aquifers theory (58), and the geological setting of Fig. 4,

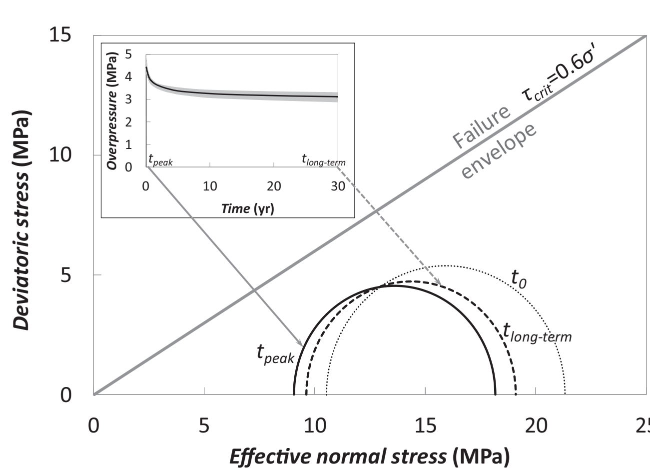

Fig. 3. Caprock stability and overpressure evolution in the reservoir at the injection well when injecting a constant mass flow rate of CO_2 (2 Mt/y) through a vertical well. The shadowed region in the inlet indicates the range of overpressures calculated by varying hydromechanical properties. Note that, initially, the stress state is far from failure conditions and that the less stable conditions occur at the beginning of injection.

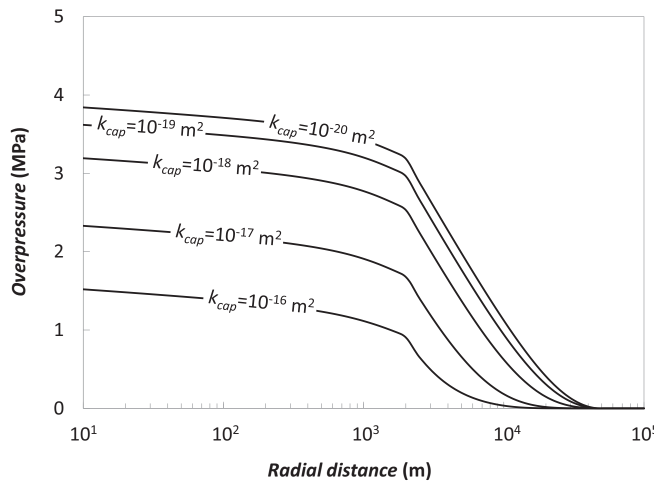

Fig. 4. Radial distribution of the overpressure at the top of the reservoir as a function of the caprock permeability after injecting 2 Mt/y during 2,000 d into a 50-m-thick formation with a permeability of 10^{-13} m^2.

the steady state would be reached after some 200 y of injection if the permeability of the seals is 10^{-18} m^2, but only after 21 y if the permeability of the seals equals 10^{-17} m^2. Thus, this steady state may take place at some CO_2 injection sites before the injection finishes.

CO_2 Dissolution

CO_2 dissolution reduces the total fluid volume filling the pores, thus reducing overpressure (59) and the risk of induced seismicity. The high solubility of CO_2 makes dissolution one of the main trapping mechanisms in the long term. For instance, it has been observed in carbonate-dominated reservoirs containing naturally occurring CO_2 that up to 90% of this CO_2 can dissolve at the millennial timescale (the remaining 10% would be trapped in precipitated minerals) (60).

CO_2 dissolution also operates over relatively short timescales and provides a significant storage capacity (61, 62). CO_2-rich brine is denser than the native brine, which causes the brine immediately beneath the CO_2 plume to be denser than the brine below. This situation is hydrodynamically unstable and leads to the formation of CO_2-rich gravity fingers that sink to the bottom of the formation and bring fresh brine upwards, forming convective cells that enhance CO_2 dissolution rate (63–67).

CO_2 dissolution is likely to occur quickly for high vertical permeability ($k > 10^{-13}$ m^2), which will lower overpressure significantly. Indeed, Elenius et al. (68) calculated that up to 50% of the injected CO_2 at Sleipner ($k = 2 \cdot 10^{-12}$ m^2), Norway, becomes rapidly dissolved when the formation brine has no dissolved CO_2. Furthermore, they estimated that between 7 and 26% of the total 15 Mt of CO_2 injected in the period 1996–2011 is already dissolved. These results are in agreement with our calculations (*SI Text*), which predict a dissolution rate at Sleipner of 12% of the injected CO_2. Still, these calculations may underestimate the actual rate at which CO_2 dissolves because they neglect the effect of dispersion, which significantly accelerates the onset of gravitational fingering (64). Furthermore, mass transfer is enhanced by convection in inclined aquifers, which are common in sedimentary basins (69). However, dissolution becomes negligible for low vertical permeability. For instance, at In Salah ($k = 10^{-14}$ m^2), Algeria, only 0.03–0.1% of the injected CO_2 dissolves into the brine (68). Therefore, only when vertical permeability is high, CO_2 dissolution will contribute to significantly reduce overpressure with time, progressively leading to a mechanically more stable situation.

Discussion and Conclusions

We have given evidence that sedimentary formations are not, in general, critically stressed (recall Figs. 1 and 2). Furthermore, overpressure will be relatively small when injecting CO_2 because (*i*) it peaks at the beginning of injection and afterward drops slightly (recall Fig. 3); (*ii*) CO_2 dissolution may occur quickly and at a significant rate, if the vertical permeability of the reservoir is high, contributing to reduce overpressure; and (*iii*) because brine, but not CO_2 because of capillarity, can flow through the caprock, overpressure will be lowered significantly and a steady state may be reached at some sites within the injection period (recall Fig. 4). The combined effect of a noncritically stressed storage formation and a small overpressure make geologic storage a safe strategy to reduce emissions of greenhouse gasses to the atmosphere.

This conclusion is not meant as an unqualified approval of any site for storage. Every site requires a proper suitability study. To this end, numerous best practices manuals are available (see ref. 70 for a review). The key issue is site characterization (71), which includes proper structural geology understanding and a good hydromechanical testing (72). Characterization may lead to dismissal of some reservoirs. Still, the point is that suitable sedimentary basins to store huge volumes of CO_2 are abundant around the world (62, 73, 74).

Experience with CO_2 storage is still limited, so few generalizations can be made. Instead, some lessons can be learnt from geothermal operations, despite the fact that these tend to concentrate in regions of anomalous thermal gradients, which are more prone to instability. For instance, fluid injection in sedimentary rocks within the overpressure ranges that are reasonable for CO_2 injection, i.e., $\Delta P < 10$ MPa, do not usually induce seismicity (3 sites with seismic events greater than magnitude 2 out of 23 injection sites reviewed by ref. 16). Induced seismicity is much more likely in crystalline rocks (3 sites with seismic events greater than M 1.9 out of 3 injection sites in granites when the injection pressure was lower or equal than 11 MPa) (16). These data confirm that, contrary to crystalline rocks, sedimentary rocks are rarely critically stressed (recall Figs. 1 and 2).

Natural seismicity should also be considered in site selection (74). Fluid injections at European sites with low natural seismicity have not produced felt events (16). Acknowledging that earthquake frequency tends to peak at plate boundaries (75, 76) further supports the suitability of most sedimentary basins due to their low natural seismicity. Furthermore, earthquake magnitude increases with depth (77–83) and therefore, large induced earthquakes ($M > 4$) that might jeopardize the caprock sealing capacity are unlikely to be triggered at the shallow depths at which CO_2 will be injected (recall Fig. 2).

In addition to a proper site characterization, overpressure management will contribute to avoid felt induced earthquakes (52, 84), as proposed by Zoback (85) for wastewater disposal. Numerical simulations have shown that CO_2 injection in closed reservoirs without a proper control of overpressure, i.e., allowing overpressure to exceed the maximum sustainable injection pressure, has the potential of triggering earthquakes of up to magnitude 4.5 in critically stressed faults (86). However, the magnitude of the simulated induced earthquakes becomes smaller than 3 when considering more realistic stress fields for sedimentary formations, with shear displacements of up to 6 cm (86, 87). These numerical studies highlight the importance of overpressure management for avoiding felt induced seismicity.

Even if a seism of sufficient magnitude occurs, CO_2 may not necessarily leak because fault permeability is reduced and entry pressure increased in faults across rocks containing clay (37). Moreover, a self-healing mechanism that prevents CO_2 leakage has been observed in argillaceous limestones (88). We conjecture that these mechanisms, together with increased buoyancy, may explain why CO_2 natural analogs often leak at shallow depths (less than 700 m, where CO_2 is gaseous), but deep natural CO_2 deposits rarely do (89).

Coupled thermo-mechanical effects also deserve attention. CO_2 will generally reach the storage formation at a temperature lower than that of the rock (90). In fact, injecting liquid (cold) CO_2 and maintaining liquid conditions along the wellbore is energetically advantageous (and therefore, it is likely to become a common practice) because it significantly reduces compression costs (91). Cold injection will cause a cold region around the injection well, which will induce thermal stress reduction. This stress reduction may lead to fracture instabilities within the reservoir (92), where induced microseismicity may be beneficial as it enhances injectivity. However, cold CO_2 injection improves caprock stability in normal faulting stress regimes because the caprock tightens as a result of stress redistribution, even in the presence of stiff caprocks (93). Thus, injection of cold CO_2 should further improve stability in tectonically stable regions.

Zoback and Gorelick (1) concluded that large-scale geologic carbon storage will be extremely expensive and risky. Economic issues fall beyond our expertise and the scope of this review (but it seems evident that economic feasibility will depend on the prize of CO_2 emissions). However, we have provided abundant evidence to state that large-scale CO_2 storage is not risky and, thus, will be a safe option to mitigate anthropogenic climate change.

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