Dear Sir,

We would like to begin by thanking you and the referees for all of your efforts with this manuscript. We would like to kindly ask you to change the article type from Research article to Review paper. I apologize for choosing the wrong article type, which has caused some confusion to the referees.

The comments have been quite constructive and we have incorporated most of the suggestions made by the referees. We believe that the explanations provided below will help in clarifying our assumptions. We have also modified the original manuscript to make them clear to all readers. As a result, we feel that this revised version has improved with respect to the original manuscript. Please find our detailed responses to each of the referees' comments below.

Sincerely yours,

Victor Vilarrasa

Topical Editor Decision: Publish subject to minor revisions (review by editor)

Comments to the Author:

Please remove Fig 3 (and relabel the other figures accordingly), it should suffice to refer to the differences in stiffness in the text.

Reply: we have removed Figure 3 and relabeled the figures accordingly.

RESPONSE TO REFEREES' COMMENTS

We discuss below the comments made by the referees and our responses. To facilitate reading, we indicate the referee's comments with C and our responses with Reply. We also indicate how we have addressed the comments in the revised manuscript with Authors' changes.

REFEREE #1

General Comments

C: The authors present and review an overview of the issues surrounding induced seismicity in geologic carbon storage. Specifically the authors attempt to show the impacts of 1) stress state, 2) pressure evolution, 3) thermal effects, and 4) fault stability on the potential for induced seismicity. They then assess the characterisation required to analyse the above and propose a number of ways to minimise the risk of induced seismicity.

Reply: We would like to begin by thanking the referee for looking in detail to this manuscript, as shown by this concise summary.

C: Whilst each of the above are treated suitably I struggle to see the major advances in this paper (above that of the cited papers) as required for a research article. It almost has the feel of a review/commentary paper. This may be enhanced by the lack of clarity on what original research is presented here as opposed to previously published citations (of which more than 130 also makes this feel more like a review). I give examples below. Specifically, there is no introduction or methods that describe what numerical modelling is actually performed. If there are new results here, they need to be shown more clearly.

Reply: We understand the referee's concern and would like to explain the peculiarity of this manuscript. As awardee of the Division Outstanding Early Career Scientists Award for the Division on Energy, Resources and the Environment (ERE) of the EGU, I was invited to publish a paper in one of the EGU journals based on my lecture. In the lecture, I presented the work that I have done in the last years and that contributed to receive the award. This is why the paper is a review and compilation of recent work. To avoid this kind of misunderstanding, we are asking the editor to change the article type from Research article to Review paper.

Specific Comments

C: Page 6. Triggering mechanisms. Many alternative mechanisms (other than pore pressure increase) are presented for seismicity triggers but the paper then only goes on to explore a few of these explicitly. For example, heterogeneity and geochemical effects are not discussed further. Thermal effects are considered but no detailed assessment of rock properties and contrast of layers. No further discussion of stress redistribution or aseismic slip. Thus I am left feeling the conclusion that seismicity can be predicted, monitored and managed is undermined by not tackling these in detail.

Reply: The objective of providing a detailed list of triggering mechanisms other than pore pressure build-up was to clearly show that the widespread idea that induced seismicity is exclusively caused by pore pressure increase is not accurate and that other processes should be considered. As for the completeness of non-isothermal effects, we agree that the effect of the contrast of rock properties between layers is relevant. For example, if the rock layers have different thermal expansion coefficient, the shear stress increases in the contact between the

two layers, which may result in damage to the lower portion of the caprock around injection wells.

Authors' changes: We have added a detailed explanation of the non-isothermal effect of having stiffness contrast between the storage formation and the caprock (see page 14, lines 11-22, in the revised manuscript). Additionally, in order to tackle all the triggering mechanisms, we have added two new Sections entitled "Shear slip stress transfer" and "Geochemical effects on geomechanical properties" (placed after the Section on "Non-isothermal effects"). In this way, we give details and discuss all the triggering mechanisms mentioned in Section 2.

C: Page 8. Stress state It is a very large assumption to say sedimentary rocks are not critically stressed. There are clearly many exampled (even cited in this paper, e.g. Blackpool) where sedimentary rocks are critically stressed. The last sentence of this section admits this but it does not appear valid to me to makes this strong assertion/ assumption, particularly as displayed in Figure 3.

Reply: The Section on "Stress state" started by stating that sedimentary rocks are generally not critically stressed. Sedimentary rocks are more ductile or plastic (sometimes called soft rocks) as compared, for instance, to igneous and metamorphic crystalline rocks, which behave in a more fragile manner. As sedimentary rocks have lower stiffness compared to other rocks, stress state is generally more isotropic, i.e., subject to less deviatoric stresses. By this, we are not affirming that they are never critically stressed, but that, in general, this is the case, which is favourable for CO_2 storage because injection is performed in sedimentary basins. To support this statement, we now provide a Table with the stress state at several CO_2 injection sites and the corresponding mobilized friction coefficient. We agree that if one does not read the caption, Figure 3 may give the impression that all sedimentary formations are not critically stressed, so we have modified the Figure to avoid this.

Authors' changes: We have rephrased most part of the Section on "Stress state". In particular, we have moved the last paragraph, where we stated that sedimentary rocks may be critically stressed, towards the beginning of the section. Additionally, we have included a Table with the stress state at several CO_2 injection sites, in which it can be seen that any of them are not critically stressed. We have also modified Figure 3 to make it clear that sedimentary rocks are less likely to be critically stressed than crystalline rocks, but that they may be critically stressed in some cases.

C: Page 9 Pressure Buildup Evolution. This may be many, and even incorrect, but is the term "pressure buildup" used correctly here? This phrase, to me, implies the early stage of injection, or the build-up to max sustained pressure. Here it used to describe what i would call 'pressure evolution' over the whole project. In the discussion of Figure 4, is this new work? How was it modelled? What are the boundary conditions, scales etc etc? Labelling on the figure also needs improved.

Reply: The described pressure evolution occurs as long as the pressure perturbation does not reach the boundaries of the aquifer. Figure 4 shows the pressure evolution for the first year of injection, but even if injection is maintained for decades e.g., 30 years, the injection pressure remains practically constant at the injection well. To avoid reaching the aquifer boundary during a 30-year injection, the radius of the model needs to be of some 100 km. In reality, we rarely find aquifers with extremely large size. If a boundary is reached by the pressure perturbation front, injection pressure will increase or decrease depending on whether the outer boundary is low-permeable or high-permeable, respectively. Beyond boundary effects, pressure tends to stabilize due to brine leakage through the caprock and base rock.

Authors' changes: We have modified the term "pressure buildup" by "pressure increase" and refer to "pressure evolution" instead of "pressure buildup evolution". We also provide an explanation of the boundary effects on pressure evolution (page 11, lines 7-13; the page and line numbers correspond to the version with track changes) and provide the necessary details of the model in the caption of Figure 4.

C: Page 10. Here the authors state that pressure dissipation can be accommodated by brine leaking through a fault but not CO_2. They need to be explicit as to why this is the case. e.g. in the last sentence of this section this should state there is high entry pressure 'to CO_2' specifically and that there is (presumably) a lower entry pressure for brine.

Reply: Since the caprock and faults are fully saturated with the resident brine, brine flow is a single phase problem, and thus, there is no entry pressure for brine flow. In addition, it should be taken into account that the pressurized area will become of several thousands of square kilometres in the long-term. Thus, even for the small flux of brine that will occur across the caprock, the total volume of displaced brine will be very large. We will explain in more detail this aspect.

Authors' changes: We now specify that the entry pressure refers to CO_2. Additionally, we have quantified the flow rate of brine that may leak through the caprock, effectively lowering pressure increase in the storage formation (page 12, lines 12-19).

C: Page 11. Non Isothermal Effects As with the pressure modelling, is this new work here? For example, on lines 6-10 of page 11 is this new work or results from Jeanne et al? lines 11-13. Is this a general comment or for a specific model/conditions? lines 16-18. Why? Is this because there is only cooling in the reservoir not caprock? line 19. Why especially in normal faulting regimes? line 21 - end of section. Is all this discussion (and figure 6) all based on modelling? As for above, what conditions, modelling approach etc etc if it is new.

Reply: As explained in the response to the General Comments, the content of this section is a compilation of recent work (both by the authors and by other contributors in the literature). All of these results are based on numerical modelling. Lines 6-13 provide a general explanation of thermo-mechanical effects which have been observed in our simulations and also by other authors. The explanation to the statement made in lines 16-18 is explained in the next paragraph. As it can be seen in the simulation results shown in Figure 5, cooling occurs both in the reservoir and the lower portion of the caprock. Thus, thermal stresses occur in both formations within the cooled region. However, the reduction in the vertical stress within the reservoir generates an imbalance in stress equilibrium. Similarly to what occurs in tunnel excavations, there is a stress redistribution around the cooled region, which results in an increase in the horizontal stresses in the lower portion of the caprock. This increase improves caprock stability in normal faulting stress regimes, because the deviatoric stress is reduced. However, the deviatoric stress increases in the lower portion of the caprock in reverse faulting stress regimes as a result of this stress redistribution. We now provide a more detailed explanation of these processes and their implications.

Authors' changes: We now explain in the manuscript the relevant conditions to understand the modelling results. We have added Figure 5a with the model setup, including the initial and boundary conditions, and we have added Table A1 in the Appendix including the material properties of the simulation results. We have written a new paragraph (page 15, lines 1-13) explaining the stability changes in the caprock in strike slip and reverse faulting stress regimes.

C: Page 14 Fault Stability. line 6-8. Surely depends on the orientation of the strata (if in sed rocks) relative to the well, not that the well is horizontal? line 24-25. What does 'more deformable' mean? Is this a condition set in the model? page 15 line 8. Why is reservoir stiffer? Is this a condition of the model again?

Reply: What we mean by horizontal well is that it has a long open section, i.e., more than 1 km, like the wells at In Salah, Algeria. If the storage formation has a slope of some degrees, a "horizontal" well should follow that inclination. Thus, we agree that the proper term is 'parallel to the strata' rather than 'horizontal well'. By 'more deformable' we mean that the Young's modulus is lower. The modelling results presented in this Section use properties measured in the laboratory. For the reservoir, we consider the properties of Berea sandstone and for the caprock and base rock we consider the properties of Opalinus clay. This is why the reservoir is stiffer than the base rock. We now provide more details on the model.

Authors' changes: We have changed 'horizontal well' by 'parallel to the strata'. We now provide all the materials properties of the model shown in this Section in Tables A2 and A3 of the Appendix.

C: Characterization techniques pg 17 line 1. Stress orientations and magnitudes are pretty hard to measure from core. Can this be changed to 'most properties'. pg 18 line 2. Do we need to be careful here about formation/caprock damage here? How is this different/beneficial to say a XLOT in the caprock? pg 19 line 1. Heterogeneity is the crucial bit here. I'm not sure you can confidently infer the next section (and figure 10) when heterogeneity could easily give the same results.

Reply: In the lab measurements from cores, we were referring to the hydraulic, thermal and geomechanical properties of the rocks. Since the sentence in p. 17 line 1 may lead to confusion, we have rephrased it. As for the potential damage to the caprock, if microseismicity is induced in the caprock, shear slip of fractures may enhance permeability (by one to two orders of magnitude according to lab rock experiments), but most importantly, may reduce CO_2 entry pressure. Thus, it is preferable to limit microseismicity in the caprock. Nevertheless, the amount of assumable damage could vary site specifically. For example, the caprock thickness at In Salah, which was of several hundreds of metres, may allow to accept some damage to the lower portion (some meters) of the caprock because the overall caprock integrity will not be compromised. XLOT should be done in the caprock to estimate the stress state, but the maximum sustainable injection pressure will be always lower than the fracturing pressure.

Authors' changes: We have rephrased the sentence regarding characterization from cores to "Hydraulic, thermal and geomechanical properties of rock can be measured in the laboratory from core samples or in the field.".

C: Minimising Risk. pg 21. line 16 onwards. This section/bulletpoint seems a little out of place here. Sure, co-injection etc. could be used but there are other ways to manage pressure too (from straight water production and disposal to changing injection rate, WAG or not etc etc) and for a section entitled other storage concepts there are lots of other methods (basalt storage e.g.). The link to geothermal energy seems out of place/unnecessary.

Reply: With this bullet point we wanted to highlight that fluids, either brine or CO_2, can be produced to lower pressure build-up. The intention was not to be an exhaustive review of all proposed methods. And we mention these two alternatives as examples.

C: Figures 4-8 in particular need more scale bars, description of colours used etc. Fig 5 in particular needs better labelling to show which Mohr diagram is for which layer.

Reply: Figures 5-8 already include the scale bar and colour description. The location of the Mohr circles shown in Figure 6 is indicated in the insets of both Figures 6a and 6b, but more details on the exact location of the points will be stated in the caption.

Authors' changes: We have added the scale bar to Figure 4. We have also adapted the colour scale in Figure 6a. We now provide the exact location of the Mohr circles in the caption of Figure 6.

REFEREE #2

General Comments

C: The authors attempt to mitigate undesirable induced seismicity by investigating different mechanisms leading to fracture/fault instability and performing numerical simulations. The authors mention that the main factors causing stress changes in the reservoir are injection-related pressure buildup, in-situ stress state, injected fluid's temperature gradient. The outline of the paper is communicated at the end of Section 1 in page 4. However, there is no clear section on what unique contributions this study is making to improve the state-of-the-art. A general theme of the manuscript is that too many generic, qualitative comments are made without new data or analysis to support those comments. There is an unreasonably large emphasis on citing and reviewing existing papers instead of showing new results. When the simulation results are shown, there are no clear quantitative details of the simulation model: model dimensions, meshing, initial and boundary conditions, well conditions, and hydraulic/mechanical properties. This suggests that the manuscript should be submitted as a review article, not Research Article.

Reply: As we explained in the response to the general comment of referee #1, this is a review article, because as awardee of the Outstanding Early Career Scientists Award for the Division on Energy, Resources and the Environment (ERE) of the EGU, I was invited to publish a paper in one of the EGU journal based on my lecture. Since I presented in my lecture the work that I have done in the last years and that contributed to receive the award, the article type should be changed from research article to review article. We apologize for this mistake when we submitted the manuscript.

Specific Comments

C: Figure 1,2,3: They are extremely generic, redundant and partially inaccurate. For example, Figure 2 shows that the effect of temperature change is to only shift the Mohr Circle to left, which is highly imprecise and can be inaccurate depending on the rock type, injection layer geometry (total stress can change), and the magnitude and direction of temperature change. Figure 3 lumps all sedimentary rocks in the world as critically unstressed and assumes that they all fail under linear Mohr Coulomb condition. This is almost unscientific and completely unnecessary.

Reply: These three Figures are schematic to explain general aspects of induced seismicity. Regarding the shift of the Mohr circle due to temperature change, it is shifted to the left because cooling is expected to occur around CO_2 injection wells, and thus, a total stress reduction will occur. We have added a minus in front of the delta T to indicate that cooling takes place. Additionally, the size of the Mohr circle changes because the changes in the total stresses may

be different in the vertical and horizontal directions. Nonetheless, it may be difficult to observe that the two circles (the red and the blue ones) have different sizes in the original Figure, so we have modified it to exaggerate this effect. As for Figure 3, we agree with the referee that not all sedimentary rocks are not critically stressed, as we already state in the figure caption and main text. We also agree with the referee that the failure envelope is not linear for rock. Indeed, we usually use non-linear shear strength in some of our studies. Since the Figure was schematic, we were just representing a linear failure surface, but we have modified it to show the non-linearity of shear strength. Additionally, we now indicate in this Figure that crystalline rock is more likely to be critically stressed than sedimentary rocks because of their higher stiffness, which makes them accumulate more stress. Additionally, to support this statement, we have added Table 1 showing the stress state at several CO_2 storage sites together with the mobilized friction coefficient. The mobilized friction coefficient ranges from 0.35 to 0.54, so in all cases is lower than 0.6, meaning that favourably oriented faults to undergo shear slip are not critically stressed. Of course, knowing the stress state at each site is crucial because the maximum sustainable injection pressure to avoid reactivating faults depends on the initial stress of state. Thus, the pressure increase at the site with a mobilized friction coefficient of 0.54 has to be lower than that at the site with a mobilized friction coefficient of 0.35.

Authors' changes: We have modified Figures 1-3 to clarify the points raised by the referee.

C: Figure 4: This shows results for a problem that is not even defined. What is the physical model setup, what are the initial and boundary conditions of the coupled flow-mechanics problem, what is the well rate and injection duration? Why do we accept this result as correct?

Reply: This Figure describes the pressure evolution in a 100-m thick reservoir in which 1 Mt of CO_2/yr are injected in an aquifer with permeability of 1e-13 m2 and radius of 100 km. Since the pressure front does not reach the outer boundary during the injection period shown in the figure, the nature of the boundary does not have any effect on the pressure evolution. The aquifer, which is placed at 1.5 km depth, initially presents hydrostatic pressure. Nevertheless, since we show the pressure changes, the absolute initial pressure is not relevant. Regardless of the particularities of this model, the intention is to describe in a general way CO_2 injection pressure evolution, which is significantly different from that of water injection. As explained in the text, the characteristics of this pressure evolution, i.e., the initial sharp increase in CO_2 pressure followed by a relatively constant injection pressure, have been observed in the field, in analytical and numerical solutions. Based on this evidence, it can be accepted as correct.

Authors' changes: We now explain the model details in the caption of Figure 4.

C: Figure 5: Same as before. Why is this an accepted solution? What is the problem setup?

Reply: The results shown in this figure are from a fully coupled numerical code that solves non-isothermal two-phase flow in deformable porous media (CODE_BRIGHT), which has been extensively benchmarked and is well accepted within the scientific community. Nevertheless, the Figure was intended to support the explanations of the processes that occur during cold CO_2 injection, without focusing on a specific case.

Authors' changes: We have included the model setup in Figure 5a and the material properties in Table A1 in the Appendix.

C: Page 9: "progressively increasing the flow rate at the beginning of injection may avoid the initial peak in pressure buildup" This statement needs to be quantified: how much increase to

avoid how much pressure buildup. Otherwise, the idea of “progressively increasing the rate” is a conjecture.

Reply and Authors’ changes: We have deleted this sentence.

C: Page 1-15: There is too much literature review. Almost 90.

Reply: We deem this amount of references appropriate for a review article.

C: Abstract: “We aim at understanding … and to develop methodologies … through dimensional and numerical analysis.” There is now dimensional analysis. In fact, the word “dimensional” appears only once in the abstract. Please remove it from the abstract.

Reply and Authors’ changes: We have removed the word dimensional in the abstract.

C: Page 14-15: This combines citations with discussion of authors’ results. This is very confusing. It is better to move authors’ own work into a separate section and not mix with background literature survey.

Reply: In this section, we are providing explanations of the relevant aspects that control fault stability. Even though we have studied this problem extensively, other authors have made relevant contributions to the topic and we believe that it is important to include their contributions in this section as well.

C: Page 15 line 5: “As a result, the induced horizontal stresses in the in-plane direction are high where the storage formation is present on both sides of the fault, but it is low where the base rock is on the other side of the fault.” This is not a result in this manuscript. Either remove it or support it with actual simulation results.

Reply: This statement results from the observation of the changes in the horizontal stress in the in-plane direction shown in Figure 7.

Authors’ changes: We have added a reference to Figure 7 at the end of the sentence.

C: Figure 7 and 8: Data used for the simulation must be provided otherwise it is not clear what to expect in the result. What is the contrast in elastic stiffness and hydraulic properties between the damage zone vs. reservoir vs. caprock. All modeling assumptions used during the simulation must be listed.

Reply and Authors’ changes: We now provide more details on the model (page 21, lines 16-19) that complement the information already provided (page 21, lines 8-16) and include the material properties in Tables A2 and A3 in the Appendix.

C: Page 17-18: This proposes a field test to macroscopically characterize hydraulic, thermal and geomechanical properties without mentioning any challenges related to applicability and operation. Otherwise such a field test will get classified as unrealistic and not useful for CO_2 injection.

Reply: We thank the referee for raising this point, which is certainly of interest and deserves discussion. There are a number of challenges related to this characterization test. To begin with, the drilling of a network of monitoring wells is not yet common practice. Monitoring techniques

also present challenges. Pressure is usually measured at the well-head, but calculating the bottom-hole pressure from the well-head pressure is not straightforward given the non-linearities of the injected fluid, especially for CO_2 injection. Unfortunately, pressure measurements in wells different from the injection well are almost non-existent. Temperature measurements receive even less attention. As for deformation measurements, ground surface deformations can be measured with InSAR data, but for characterization tests that last a few days, the deformation of the ground may not be detectable given the great depths of storage formations. Thus, deformation should be measured at depth within the boreholes. These measurements pose the question of whether the measured deformation refers to that of the rock or to that of the well. Since the casing of wells is stiffer than rock, the rock may deform more than the well and sliding could even occur between the rock and the cement surrounding the well casing. Fiber optic may solve part of these monitoring challenges, but the way how this monitoring should be performed is still not crystal clear for the moment. As far as microseismicity monitoring is concerned, arrays of geophones are certainly needed to be placed at depth. Otherwise, the signal-to-noise ratio is too high, which complicates detecting microseismic events. Additionally, multi-sensor arrays with a wide aperture coverage are necessary to accurately locate the events.

Authors' changes: We now include in the manuscript this discussion on the challenges of performing such characterization test (page 26, lines 12-25 and page 27, lines 1-7).

C: Page 21: "predictive models of induced seismicity that consider coupled THMS processes should be applied" This is much easier said than done. What are these models? The results in this manuscript do not show any coupling to seismicity, which requires solution of the elastodynamic problem in a n-dimensional domain with a (n-1) dimensional fault surface, not a n-dimensional fault zone. This manuscript presents neither an approach nor results from coupling of the four processes T, H, M, S.

Reply: This is a recommendation we made for future practices based on our previous experience. Given that we do not go into the details of the seismic part, we will replace THMS by THM, which is discussed in the manuscript.

Authors' changes: We have removed the seismic part.

C: Page 21: "The continuous characterization will permit updating the fault stability analysis by incorporating newly detected faults." How will the new faults be detected? This is not trivial and not answered in this manuscript. So, please remove this.

Reply: The continuous characterization refers to the methodology explained in Figure 10. Thus, by applying this methodology, it is possible to detect previously unidentified low-permeable faults and incorporate them in the model of the injection site.

Authors' changes: We now mention Figure 10 at the end of this sentence to clarify how new faults can be detected.

C: Figure 6: Color scale can be improved. For example, it is different for the upper and lower figures, yet the maximum value is not visible in the upper figure.

Reply and Authors' changes: We have modified the colour scale of Figure 6a so that the maximum and minimum values are visible.

Induced seismicity in geologic carbon storage

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ABSTRACT

Geologic carbon storage, as well as other geo-energy applications, such as geothermal energy, seasonal natural gas storage and subsurface energy storage, imply fluid injection/extraction that causes changes in ~~the effective~~rock stresses field and may induce~~s~~ (micro)seismicity. If felt, seismicity has a negative effect on public perception and may jeopardize wellbore stability and damage infrastructure. Thus, induced earthquakes should be minimized to successfully deploy geo-energies. However, numerous ~~the~~ processes ~~that~~ may trigger induced seismicity, which contributes to making it complex and ~~are not fully understood, which~~ translates into a limited forecast ability of current predictive models. We ~~aim at understanding~~review the triggering mechanisms of induced seismicity ~~and to develop~~present ~~methodologies to minimize its occurrence through dimensional and numerical analysis~~. Specifically, we analyze (1) the impact of pore pressure evolution and ~~We find that t~~~~t~~~~T~~he effect that properties of the injected fluid~~, e.g., water or CO_2,~~ have ~~a significant effect~~ on ~~pore pressure buildup evolution and thus, on~~ fracture/fault stability; (2) non-isothermal effects caused by the fact that ~~. In addition to pressure changes,~~ the injected fluid usually reaches the injection formation at a lower temperature than that of the rock, inducing rock contraction, thermal stress reduction and stress redistribution around the cooled region; (3) ~~. If low-permeable faults cross the injection formation,~~ local stress changes ~~are~~ induced ~~around~~ when low permeability faults cross the injection formation,~~them~~ which may reduce their stability and eventually cause fault reactivation; (4) stress transfer caused by seismic or aseismic slip; and (5) geochemical effects, which may be especially relevant in carbonate containing formations. We also review ~~. To minimize the risk of inducing felt seismicity, we have present developed~~ characterization techniques developed by the authors to reduce the uncertainty on rock properties and subsurface heterogeneity both for the screening of

injection sites and for the operation of projects. Based on the review, we propose a methodology ~~Overall, we contend that felt induced seismicity can be minimized provided that a~~based on proper site characterization, monitoring and pressure management ~~are performed.~~to minimize induced seismicity.

Keywords: ~~fluid~~ CO_2 injection, pressure ~~buildup~~evolution, coupled processes, caprock integrity, fault reactivation

1. INTRODUCTION

The interest in subsurface energy resources, such as geologic carbon storage, geothermal energy~~, seasonal natural gas storage,~~ and subsurface energy storage ~~and geologic carbon storage~~, has significantly increased as a means to mitigate climate change (IPCC, 2018). In particular, geologic carbon storage has the potential to store large amounts of carbon dioxide (CO_2) in deep geological formations, reducing CO_2 emissions to the atmosphere (Hitchon et al., 1999; Celia, 2017). Such subsurface energy-related activities imply fluid injection/extraction that change the pore pressure and thus, the effective stresses, causing deformation and potentially fracture and/or fault reactivation that may lead to induced (micro)seismicity (Ellsworth, 2013; Grigoli et al., 2017).

Induced microseismicity, i.e., seismicity of such low magnitude that is not felt on the ground surface (typically moment magnitude~~,~~ M<2), is positive if confined within the injection formation because shear slip of fractures enhances permeability (Yeo et al., 1998; Vilarrasa et al., 2011; Rutqvist, 2015). This permeability enhancement permits injecting the same amount of fluid at a lower injection pressure, thus reducing compression costs. However, induced microseismicity should be avoided in the caprock because its sealing capacity could be compromised, which could lead to CO_2 leakage.

Additionally, if felt, induced earthquakes may damage wells, buildings and infrastructure and may cause fear and nuisance ~~among~~ to the local population (Oldenburg, 2012). As a result of these negative effects, several geo-energy projects have been cancelled before they entered into operation, such as ~~an~~ the enhanced geothermal systems (EGS) at Basel, Switzerland (Häring et al., 2008; Deichmann et al., 2014) and Pohang, South Korea (Grigoli et al., 2018; Kim et al., 2018), a ~~geothermal~~ hydrothermal project at Sankt Gallen, Switzerland (Edwards et al., 2015; Diehl et al., 2017) and a~~the~~ seasonal gas storage project ~~of~~ at Castor, Spain (Cesca et al., 2014; Gaite et al., 2016). Thus, felt induced seismic events have to be minimized, and ideally avoided, in order to achieve a successful deployment of geo-energy projects.

Geologic carbon storage projects, both at large scale and pilot scale, have not induced any felt earthquake to date (White and Foxall, 2016; Vilarrasa et al., 2019). This lack of felt seismicity may be due to some favorable aspects of CO_2 storage with respect to water injection that will be explained in this paper. Yet, induced microseismicity is common, such as at In Salah, Algeria (Stork et al., 2015; Verdon et al., 2015), Decatur, Illinois (Kaven et al., 2015; Bauer et al., 2016), and Otway, Australia (Myer and Daley, 2011), projects. Despite the ~~previous~~ absence of felt seismicity to date, proper protocols should be defined and followed to avoid inducing felt earthquakes in future geologic carbon storage projects.

The aim of this paper is to ~~examine~~ review the potential causes of induced seismicity in geologic carbon storage and to explain methodologies that can serve to minimize the risk of inducing felt seismic events. First, we introduce the potential triggering mechanisms of induced seismicity and then, we go into details of each of them ~~are explained~~. ~~Next~~Specifically, we review the stress state of deep geological formations, the pore pressure ~~buildup~~ evolution, ~~and~~ non-isothermal effects resulting from CO_2 injection,

shear slip stress transfer and geochemical effects on geomechanical properties ~~are described~~and how these effects may lead to induced microseismicity. ~~Then~~Afterwards, we analyze how CO_2 injection affects fault stability ~~is analyzed~~ and, finally, we present subsurface characterization techniques that can be used ~~for~~ to minimize~~ing~~ the occurrence of felt induced seismicity ~~are presented~~.

2. TRIGGERING MECHANISMS

The basic principle of induced seismicity is that the pressure build-up caused by fluid injection reduces the effective stresses, which brings the stress state closer to failure (Figure 1). If failure conditions are reached, the elastic energy stored in the rock mass is released and a (micro)seismic event is induced. Failure in geomaterials can occur either in tensile or shear mode (Jaeger et al., 2009). While tensile failure induces microseismic events of such low magnitude that cannot be felt on the ground surface, shear failure may lead to felt earthquakes if a sufficiently large area of a pre-existing discontinuity, i.e., a fracture or fault, is reactivated. Nevertheless, in the cases in which tensile failure is sought, i.e., to create hydraulic fractures ~~in low permeable rock~~ to enhance ~~its~~ rock permeability, shear failure of pre-existing faults may also occur if they become pressurized during the hydraulic fracturing operations. In such situation, ~~which may induce~~ felt earthquakes associated to hydraulic fracturing operations may occur (Rubinstein and Mahani, 2015). For example, a felt earthquake occurred at the Preese Hall 1 exploration well for shale gas near Blackpool, UK, during hydraulic fracturing because a pre-existing nearby fault was reactivated (Clarke et al., 2014).

In principle, fluid pressure buildup may seem the only mechanism that induces seismicity. Thus, intuition suggests that stability should improve in the vicinity of the injection well

after injection is stopped because fluid pressure drops rapidly. Far away from the injection well, fluid pressure continues to rise and thus, pressure-diffusion could explain continued post-injection induced seismicity (Hsieh and Bredehoeft, 1981), which is often observed ~~for example~~ after ~~the~~ stimulation of ~~enhanced geothermal systems (~~EGS~~)~~ (Parotidis et al., 2004). However, pressure-diffusion cannot explain why the magnitude of post-injection seismicity is often higher than that induced during injection, e.g., at Basel, Switzerland (Deichmann and Giardini, 2009), at Soultz-sous-Forêts, France (Evans et al., 2005), and at Castor, Spain (Gaite et al., 2016). Even though this high magnitude post-injection seismicity has not been observed in geologic carbon storage projects, its causes should be understood ~~in order~~ to ~~avoid~~ prevent its~~ occurrence~~. The counterintuitive occurrence of large magnitude post-injection induced seismicity ~~is due to~~may be explained by the fact that fluid injection in the subsurface involves coupled processes that are more complex than just the hydraulic effect:

- The stress state changes in response to pore pressure variations (Streit and Hillis, 2004; Rutqvist, 2012). Specifically, the total stress increases in the direction of flow due to the lateral confinement that opposes to the expansion of the rock in this direction (Zareidarmiyan et al., 2018). This poro-mechanical effect modifies the initial stress state and thus, the analysis of fault stability cannot be performed as a simple subtraction of the pressure build~~-~~up from the initial effective stress state;~~.~~
- The injected CO_2 usually reaches the injection depth at a colder temperature than that of the rock because CO_2 does not reach thermal equilibrium with the geothermal gradient along its way down the well (Paterson et al., 2008). As a result, the ~~injection~~ storage formation cools down around the injection well, inducing a thermal stress reduction that brings the stress state closer to failure

conditions (Vilarrasa and Rutqvist, 2017). The magnitude of induced thermal stresses is proportional to the rock stiffness. Thus, induced thermal stresses depend on the rock type in which fluid is injected, becoming larger in reservoir rocks than in clay-rich caprocks because ~~they~~ reservoirs are usually stiffer (Vilarrasa and Makhnenko, 2017)~~;~~.

- The stress changes that arise in the storage formation and the caprock as a result of pressure build~~-~~up and cooling vary depending on the rock properties and the contrast between geological layers (Verdon et al., 2011)~~;~~.
- Each (micro)seismic event provokes a stress redistribution around the portion of the fracture or fault that undergoes shear slip (Okada, 1992). This stress transfer controls the distribution of aftershocks in natural seismicity (King et al., 1994) and may be the reason for observed rotations in the direction of the sheared faults in sequences of induced seismicity during stimulation of EGS (De Simone et al., 2017a)~~;~~.
- Not all the shear slip occurring in fractures or faults induces seismic events. Actually, shear slip may occur aseismically (Cornet et al., 1997). This aseismic slip may induce (micro)seismic events away from the slipped surface (Guglielmi et al., 2015)~~;~~.
- Geochemical reactions may alter the frictional strength of faults, which could lead to failure conditions if a fault is weakened~~;~~ ~~However, laboratory studies have shown that this effect is in general minor (Rohmer et al., 2016), even on fault gouges that have been exposed to acidic conditions for a long period in natural CO_2 reservoirs (Bakker et al., 2016).~~
- Heterogeneity in the rock type, strength of faults and the stress field, which may present local variations around faults (Faulkner et al., 2006), affect fault stability.

~~However, the knowledge on the role of heterogeneity in induced seismicity is still limited.~~

All these potential triggering mechanisms are usually neglected because pressure-diffusion is considered sufficient to explain induced seismicity. Though pore pressure diffusion alone may explain certain sequences of induced events (Shapiro et al., 2002), seismic sequences are usually more complex and imply a combination of several coupled processes. For example, cooling-induced stresses resulting from CO_2 entering the storage formation 45 ºC colder than the rock may explain part of the microseismicity detected at In Salah, Algeria (Vilarrasa et al., 2015). Another example is Weyburn, Canada, where the scarce microseismic events (around 200) that were induced in the caprock at the beginning of injection were interpreted to be caused by stress changes resulting from the contrast in stiffness between the reservoir and caprock (Verdon et al., 2011). Thus, when assessing the potential for induced (micro)seismicity of CO_2 storage projects, all these coupled processes should be considered (Figure 2).

3. STRESS STATE

A careful examination of the subsurface stress state reveals that ~~while~~ crystalline rocks ~~are critically stressed,~~accumulate more stress as a result of tectonics than sedimentary rocks (Vilarrasa and Carrera, 2015). The dependence of the stress state on the rock type ~~is due to~~reflects the contrast in the rock stiffness. Since crystalline rocks are much stiffer than sedimentary rocks, stresses induced by tectonics mainly accumulate in the crystalline basement. In contrast, the relatively soft sedimentary rocks deform without accumulating large stresses and as a result they do not usually become critically stressed. This is demonstrated in ~~It goes without saying there may be cases of critically stressed~~

~~sedimentary rocks, which may lead to unexpected high seismicity if no stress measurements are performed.~~~~are generally not critically stressed (Vilarrasa and Carrera, 2015). Since CO_2 will be stored in sedimentary basins, their absence of~~the less likely ~~criticality of stress implies that a certain pressure buildup and cooling can be applied without reaching failure conditions (Figure 3).~~

Table 1, which displays ~~presents~~ the estimated stress state at several CO_2 storage sites with the corresponding mobilized friction coefficient, $\mu_{mob}=\tan\phi'_{mob}$. where ϕ'_{mob} is the mobilized friction angle. ϕ'_{mob} is the angle that forms the tangent to the Mohr circle assuming no cohesion. Thus, if the mobilized friction coefficient is lower than the actual friction coefficient, which is generally equal to 0.6 (Barton, 1976), the rock is not critically stressed. Interestingly, the mobilized friction coefficient is lower than 0.6 for all the CO_2 storage sites included in Table 1. Since CO_2 will be stored in sedimentary basins, the less likely criticality of stress implies that a certain pressure buildup and cooling can be applied without reaching failure conditions ~~(Figure 3)~~. ~~Still~~Yet, there may be cases of critically stressed sedimentary rocks, which may lead to unexpected seismicity if no stress measurements are performed. Therefore, mechanical characterization must be required at potential storage sites.~~However,~~

T~~t~~he stress state at each site should be measured in order to determine the maximum sustainable injection pressure and maximum ~~temperature drop~~cooling that would lead to a safe CO_2 storage (Rutqvist et al., 2007; Kim and Hosseini, 2014). Thus, stress measurements should be routinely performed during wellbore perforation, determining both the magnitude and orientation of the principal stresses (Cornet and Jianmin, 1995). ~~Once the stress state is known, t~~The range of ~~fault~~ strikes and dips of potentially reactivated faults ~~that is favorably oriented for~~can ~~reactivation can~~ be determined once the stress state is known~~,~~ (Morris et al., 1996). This exercise is crucial to identify faults

that may induce large seismic events, ~~and~~ to foresee an optimal design of the injection strategy and to define mitigation measures (e.g., Birkholzer et al., 2012; Buscheck et al., 2012; Dempsey et al., 2014) if induced seismicity is predicted to possibly occur above a predefined threshold.

~~The dependence of the stress state on the rock type is due to the contrast in the rock stiffness. Since crystalline rocks are much stiffer than sedimentary rock, stresses induced by tectonics mainly accumulate in the crystalline basement. In contrast, the relatively soft sedimentary rocks deform without accumulating large stresses and as a result they do not usually become critically stressed. It goes without saying there may be cases of critically stressed sedimentary rocks, which may lead to unexpected high seismicity if no stress measurements are performed.~~

4. PRESSURE ~~BUILDUP~~ EVOLUTION

The pressure ~~buildup~~ evolution of CO_2 injection is favorable to achieve a long-term geomechanically stable situation. In contrast to water injection, which yields a linear increase of pressure with the logarithm of time when a continuous flow rate is injected (Theis, 1935), CO_2 leads to a peak at the beginning of injection followed by a relatively constant overpressure ~~buildup increase~~ (Figure 3~~4~~). Thus, pressure ~~buildup~~ evolution is relatively easy to control in CO_2 injection operations, which should help to minimize induced (micro)seismicity (Vilarrasa and Carrera, 2015). Such pressure evolution has been observed in the field, at Ketzin, Germany (Henninges et al., 2011), numerically (e.g., Vilarrasa et al., 2010; Okwen et al., 2011) and analytically (Vilarrasa et al., 2013a).

The initial sharp increase in pore pressure ~~buildup~~ is due not only to viscous forces opposing fluid displacement, but also to capillary forces caused by the desaturation

around the injection well~~to a local reduction in permeability caused by the desaturation around the injection well (Figure 4b)~~, which decreases the relative permeability ~~of~~ to both CO_2 and water (Figure 34b). However, once CO_2 fills the pores around the injection well (Figure ~~4c~~3c), the CO_2 relative permeability rises. Additionally, since CO_2 viscosity is one order of magnitude lower than that of brine, CO_2 can flow easily inside the storage formation, which leads to a constant or even a slight drop in overpressure ~~buildup~~ (Figure ~~4a~~3a). This constant evolution of fluid pressure is maintained as long as the pressure perturbation ~~front~~ does not reach a boundary.~~, possibly through leakage across the caprock~~Once a~~an outer~~ boundary is reached, pressure will decrease in the presence of a constant pressure boundary and will increase in the presence of a ~~low-permeable~~low permeability boundary. The pressure evolution shown in Figure 3 is not affected by boundary effects because the pressure p~~front~~erturbation does not reach the outer boundary during the displayed injection time. ~~–~~This fluid pressure evolution induces the largest effective stress changes in the caprock at the beginning of injection, coinciding with the peak in pressure ~~buildup~~increase. ~~Thus, progressively increasing the flow rate at the beginning of injection may avoid the initial peak in pressure buildup, minimizing the effect on the caprock integrity.~~

Maintaining the caprock integrity in the long-term is ~~also~~ favored by two effects that tend to decrease overpressure ~~buildup~~ inside the storage formation: (1) CO_2 dissolution into the resident brine, and (2) brine flow across the low-permeability formations that confine the storage formation, i.e., caprock and base rock (Vilarrasa and Carrera, 2015). On the one hand, when CO_2 dissolves into brine, fluid pressure decreases because the total fluid volume is reduced (Mathias et al., 2011a; Steele-MacInnis et al., 2012). As observed in natural analogues, the percentage of CO_2 that may eventually become trapped by dissolution can be as high as 90% in carbonate storage formations (Gilfillan et al., 2009).

In the short-term, CO_2 dissolution can also be high in storage formations with high vertical permeability (k>10^{-13} m^2) because of the formation of gravity fingers induced by the unstable situation of having a fluid of a higher density, i.e., ~~of~~ CO_2-rich brine, above a fluid of lower density, i.e., the resident brine (Riaz et al., 2006; Hidalgo and Carrera, 2009; Pau et al., 2010). On the other hand, caprock permeability at the field scale is two to three orders of magnitude larger than that at the core scale as a result of the presence of fractures and faults (Neuzil, 1994). Thus, resident brine of the storage formation can flow across the caprock and base rock, lowering the pressure buildup inside the storage formation. Though brine can flow through the caprock because single phase flow is not hindered by ~~ca~~pillarity, CO_2 cannot because of the high CO_2 entry pressure of clay-rich formations (Benson and Cole, 2008).

To quantify the flow across the caprock in the long-term, let us assume a 100-m thick caprock with permeability of 10^{-18} m^2, water viscosity of $4 \cdot 10^{-4}$ Pa·s (assuming a temperature of 60 ºC) and a mean overpressure of 1 MPa distributed in a radial distance of 20 km. This scenario yields a flux across the caprock of $2.5 \cdot 10^{-11}$ m/s in an area of $1.26 \cdot 10^{9}$ m^2. Thus, the flow rate across the caprock is of 0.031 m^3/s, which is in the order of magnitude of industrial scale injection rates (in the order of 0.05 m^3/s for annual megaton injection), effectively lowering the pressure increase inside the storage formation.

5. NON-ISOTHERMAL EFFECTS

In addition to pressure ~~buildup~~increase, thermal effects are also relevant in geologic carbon storage because temperature changes induce thermal stresses that affect fracture stability (Vilarrasa and Rutqvist, 2017). CO_2 reaches the bottom of the injection well at a

temperature lower than that of the storage formation because CO_2 flow within the well is isenthalpic (Pruess, 2006) and thus, it heats up at a lower rate than the geothermal gradient (Lu and Connell, 2008). As a result, the rock around injection wells cools down.

To illustrate ~~this cooling and its~~the effect on fracture stability, we present the simulation results of cold CO_2 injection into a deep saline aquifer. Figure 4a displays the model setup with the initial and boundary conditions. ~~and T~~the material properties are included in Table A1 in the Appendix. ~~(Figure 5b).~~ The advance of the cooling front with respect to the CO_2 plume is retarded because the rock has to be cooled down (compare Figures ~~5~~4b~~a~~ and 5c~~b~~) (Bao et al., 2014; LaForce et al., 2015; De Simone et al., 2017b). Cooling mainly advances by advection in the reservoir, but it also extends into the lower portion of the caprock by conduction (Figure ~~5~~4c~~b~~). The extent of the cooling region can become of a few hundreds of meters after some decades of CO_2 injection at industrial scale rates, i.e., megaton injection (Vilarrasa et al., 2014). Thus, unless faults are present in the vicinity of the injection well, they will not be directly affected by cooling. Nevertheless, faults ~~placed~~ located far from the cooling region may undergo stability changes as a result of the contraction of the cooled rock, which causes ~~a~~ changes in ~~the~~ far-field stresses (Jeanne et al., 2014).

The cooling-induced rock contraction and thermal stress reduction ~~approach~~ shift the stress state towards shear failure conditions and, theoretically, tensile fractures could be formed if the tensile strength was reached (Luo and Bryant, 2010; Goodarzi et al., 2010; 2012; Gor et al., 2013). The temperature-induced stresses are not isotropic (Figure 5), and thus, the effect on fracture stability depends on the stress regime, i.e., normal faulting, strike-slip or reverse faulting (Vilarrasa, 2016). In general, fracture stability becomes more compromised in the reservoir than in the caprock, which may lead to injectivity enhancement while maintaining the caprock sealing capacity (Goodarzi et al., 2015;

Vilarrasa et al., 2017a). ~~This favorable situation specially occurs in normal faulting stress regimes (Vilarrasa et al., 2013b; Kim and Hosseini, 2015).~~

This favorable situation ~~specially~~ occurs especially in normal faulting stress regimes (Vilarrasa et al., 2013b; Kim and Hosseini, 2015). Figure ~~6~~ 5 displays how ~~the~~ stress ~~changes that are~~variations induced in the reservoir and caprock as a result of cooling ~~and how they~~ affect fracture stability in a normal faulting stress regime (i.e., vertical stress ~~small~~larger than horizontal stresses). Both the vertical and horizontal stresses decrease inside the reservoir within the cooled region. The~~is~~ stress reduction is proportional to the rock stiffness, the rock thermal expansion coefficient and the temperature change. The vertical stress reduction within the reservoir causes a disequilibrium in this direction because the overburden on top of the reservoir remains constant, so that vertical stresses become smaller than the weight of the material above (Figure ~~6a~~5a). Thus, to satisfy stress equilibrium and displacement compatibility, an arch effect develops to support the weight of the material above, leading to a reduction of ~~the~~ horizontal stresses within the reservoir and an increase in the lower portion of the caprock~~, tightening it~~ (Figure ~~6b~~5b). ~~As a~~The net result of these stress changes is to: (1) bring the reservoir towards~~,~~ shear failure conditions (the Mohr circles shifts to the left and increases in size, Figure ~~6~~5c)~~are reached within the reservoir~~, ~~but~~ and (2) improve stability of ~~the~~ the caprock by tightening it ~~remains stable~~ (~~see~~ the Mohr circle becomes smaller, ~~s in~~ Figure~~s 6c and~~ 5d). This contrast in stability between the reservoir and the caprock is highlighted in Figure ~~5~~4d~~c~~, which shows that plastic strain, i.e., strain that occurs because failure conditions have been reached, only takes place in the reservoir and not in the caprock (for details on the failure surface, see Vilarrasa and Laloui, 2015). ~~Thus, cold CO_2 injection, i.e., in liquid state (Vilarrasa et al., 2013b), should not be feared because the caprock sealing capacity is not compromised.~~

The situation is slightly different in a reverse faulting stress regime, where~~. Contrary to the normal faulting stress regime,~~ the vertical stress is the minimum principal stress (Vilarrasa, 2016)~~, instead of the maximum~~. ~~As a result~~The cooling-induced increase of horizontal stress in the lower portion of the caprock causes ~~, the size of~~ the Mohr circle to increases in size (i.e., the deviatoric stress increases) ~~in the lower portion of the caprock~~. Nevertheless, thise increase ~~in the deviatoric stress~~ is slight because of the high confinement in reverse faulting stress regimes. ~~But~~Still, ~~since the deviatoric stress is not decreased in the lower portion of the caprock,~~ shear failure may occur as a result of cooling. Similarly, the deviatoric stress is maintained in a strike slip stress regime (Vilarrasa, 2016), which may induce shear failure of pre-existing fractures, and thus, induced microseismicity, in the cooled region of the caprock, as was likely the case at In Salah, Algeria (Vilarrasa et al., 2015). These results highlight again the importance of characterizing the stress state.

The simulation results shown in Figures 4 and 5 consider that the thermal expansion coefficient of the storage formation and the caprock are equal. Despite the limited range of the values that the thermal expansion coefficient can take in geomaterials, its magnitude will generally vary between the two formations. Different thermal expansion coefficients between the storage formation and the caprock lead to differential expansion of the rock, building up shear stress in the interface between the two layers. When the thermal expansion coefficient of the caprock is greater than that of the storage formation, deviatoric plastic strain may occur in the lower portion of the caprock as a result of cooling (Vilarrasa and Laloui, 2016). Nonetheless, regardless of the stress regime and the relative values of the thermal expansion coefficient between the storage formation and the caprock, the overall sealing capacity of the caprock is not compromised because only the lower portion of the caprock is affected by cooling and the subsequent stress changes.

6. SHEAR SLIP STRESS TRANSFER

Shear slip of faults induce static stress transfer, decreasing stability in some regions, where seismicity rate increases, and increasing stability in others, the so called stress shadows, where seismicity rate decreases or is even suppressed (Harris and Simpson, 1998). Static stress transfer resulting from induced earthquakes has been found to be relevant for explaining post-injection events in EGS stimulations (Schoenball et al., 2012; De Simone et al., 2017). The stress transfer causes rotation of the stress tensor, changing the orientation of the faults that are critically oriented to undergo shear failure. Such change in the orientation of the faults that rupture during water injection and after shut-in was observed at the EGS Basel Deep Heat Mining Project (Deichmann et al., 2014).

Shear slip does not need to be seismic in order to induce stress transfer. Actually, aseismic slip has been reported to indirectly induce seismicity in non-pressurized fault patches (Cappa et al., 2019). The capacity of injection-induced aseismic slip for bringing to failure zones of faults that are not pressurized has been measured in decameter scale rock laboratories (Guglielmi et al., 2015; Duboeuf et al., 2017). The magnitude of the induced microseismicity in these field experiments is small, in the order of -3.5 (Duboeuf et al., 2017). However, magnitudes may become large in industrial operations if aseismic slip stresses faults below the injection formation. For example, induced earthquakes with magnitude up to 5 were triggered close to a geothermal plant at Brawley, California, USA (Wei et al., 2015). The accumulated aseismic slip inducing these earthquakes was estimated to be of some 60 cm, nucleating the earthquakes 5 km below the injection formation.

Both seismic and aseismic slip induce stress transfer that affects fracture and fault stability and may induce (micro)seismicity. This effect has been widely studied in natural seismicity, but has received relatively little attention in induced seismicity. Nonetheless, recent studies show that it is a non-negligible effect, ~~and~~ which is relevant in post-injection seismicity and for explaining induced events in non-pressurized regions (De Simone et al., 2017a; Cappa et al., 2019). Thus, even though ~~there has not been found evidence to date of~~ microseismicity induced by shear slip stress transfer~~-~~ has not been observed to date at geologic carbon storage sites, it should be considered as a potential triggering mechanism.

7. GEOCHEMICAL EFFECTS ON GEOMECHANICAL PROPERTIES

The dissolution of CO_2 into the resident brine forms an acidic solution that has the potential of dissolving minerals, which in turn may lead to subsequent precipitation of other minerals (Zhang et al., 2009). The ~~largest~~fastest geochemical reactions occur in carbonate rocks and in rocks with carbonate-rich cement (Vilarrasa et al., 2019). Carbonate minerals dissolve when they interact with the acidic CO_2-rich brine, leading to porosity and permeability increase (Alam et al., 2014). The porosity increase leads to a reduction in rock stiffness and strength, which has been measured in the laboratory to be in the order of 20-30% (Bemer and Lombard, 2010; Vialle and Vanorio, 2011; Vanorio et al., 2011; Kim et al., 2018). The measured changes become smaller for increasing confining pressure (Vanorio et al., 2011) because the higher the confinement, the lower the porosity and ~~thus,~~ the available reactive surface and, thus, the reaction rate. The reduction in rock stiffness affects the strain and stress induced by CO_2 injection and the reduction in strength may cause failure of initially stable fractures and faults (recall Figure

2), leading to induced microseismicity. Thus, the changes in ~~the~~ geomechanical properties ~~in~~of ~~carbonate-rich~~ rocks (especially carbonate-rich rocks) as a result of CO_2-brine-rock geochemical interactions should be evaluated in the laboratory in order to properly assess the induced microseismicity potential.

Caprocks are also affected to some extent by geochemical reactions. Carbonate and feldspar minerals dissolve in shale, leading to precipitation of other carbonate minerals (Yu et al., 2012). But the overall response of caprocks depend on the rock type. While certain caprocks undergo permeability increase due to interaction with CO_2 (Olabode and Radonjic, 2014), others present a self-sealing response to CO_2 flow due to porosity decrease (Espinoza and Santamarina, 2012) or fracture clogging (Noiriel et al., 2007). Nevertheless, CO_2 is only expected to penetrate a short distance, if any, into the caprock because of its ~~low-permeability~~high entry pressure, which ~~hinders~~prevents upwards CO_2 flow ~~and leads to its dissolution into the pore water, minimizing the affection to the geomechanical properties and the risk of leakage~~ (Busch et al., 2008).

For other types of host rocks~~the rest of rocks~~,~~However,~~ laboratory studies have shown that ~~this effect~~geochemically-induced changes in the geomechanical properties is in general minor (Rohmer et al., 2016). This minor effect has also been observed~~, even~~ i~~o~~n fault gouges that have been exposed to acidic conditions for a long period in natural CO_2 reservoirs (Bakker et al., 2016). ~~As a result, even though~~In summary, there is no evidence to expect significant ~~the~~ alteration of geomechanical properties induced by geochemical reactions ~~may not be a concern~~ in general, but (1) the issue should not be abandoned and (2) it should receive especial~~ly~~ attention and site-specific studies ~~should be paid to it~~ in carbonate-rich rocks.

~~6.~~8. FAULT STABILITY

Faults are present at ~~the field and basin scale~~all scales and have been observed to play a role ~~, as observed~~ in CO_2 storage projects (e.g., Vidal-Gilbert et al., 2010; Rutqvist, 2012; Castelletto et al., 2013a). To name a few, (i) a fault or fractured rock zone opened as a result of pressure ~~buildup~~ increase at In Salah, Algeria, leading to a double-lobe pattern of uplift on the ground (Vasco et al., 2010; Rinaldi and Rutqvist, 2013); (ii) the storage formation at Snøhvit, Norway, was surrounded by ~~low-permeable~~low permeability faults, which limited its storage capacity (Hansen et al., 2013; Chiaramonte et al., 2015); (iii) the Spanish pilot test site at Hontomín contained several minor faults within a few hundreds of meters from the injection well (Alcalde et al., 2013; 2014); and (iv) the pilot test site at Heletz, Israel, is placed in an anticline crossed by two faults, confining the storage formation to be a few hundreds of meters wide (Figueiredo et al., 2015). The nature of these faults, i.e., flow barriers or conduits (Caine et al., 1996), controls the stress changes occurring around the fault and thus, fault stability (Vilarrasa et al., 2016). ~~Low-permeable~~Low permeability faults may lead to the premature closure of storage sites because of pressure limitations on the storage capacity of the formation (Szulczewski et al., 2012). Actually, if multiple ~~low-permeable~~low permeability faults are present and intersecting each other, they will lead to a compartmentalized reservoir (Castelletto et al., 2013b). In such cases, pressure would increase linearly with time (Zhou et al., 2008; Mathias et al., 2011b), increasing injection costs and eventually leading to fault reactivation, and thus induced seismicity, if injection is maintained ~~at a constant rate~~ (Cappa and Rutqvist, 2011a; Pereira et al., 2014; Rutqvist et al., 2016).

Changes in fault permeability due to its reactivation depend on the type of material. Fault reactivation may enhance fault permeability in hard rocks due to dilatancy by one to two orders of magnitude (Cappa and Rutqvist, 2011b; Guglielmi et al., 2015). This

permeability increase raises the question of whether fault reactivation may lead to CO_2 leakage ~~or not~~. Such assessment ~~should~~ must be made site specifically taking into account the hydro-mechanical properties of the rock and faults. Nonetheless, in general, faults crossing sequences of reservoirs and caprocks maintain a low-permeability, at least, in the sections that cross caprocks as a result of the high clay content of the fault (Takahashi, 2003; Egholm et al., 2008). But more importantly, the CO_2 entry pressure of the fault remains high in the caprock sections (Vilarrasa and Makhnenko, 2017), hindering upwards CO_2 leakage, as observed in numerical simulations that incorporate fault heterogeneity (Rinaldi et al., 2014). Additionally, the stress state of the upper crust, which is characterized by a critically stressed crystalline basement overlaid by generally non-critically stressed sedimentary rock (recall Section 3), favors nucleation of the largest seismic events in the crystalline basement rather than in the sedimentary rock where CO_2 is stored. This hypocenter distribution has been observed in central US as a result of wastewater injection in the basal aquifer, which ~~implies that~~is consistent with permeability enhancement ~~occurs~~ below the storage formation but not ~~and thus, fault permeability~~ in the caprock and above ~~it remains unaltered~~, which limit~~sing~~ the risk of CO_2 leakage (Verdon, 2014).

Apart from CO_2 leakage, the magnitude of ~~the~~ potential induced earthquakes is a concern because of the damage and fear that they could generate. The magnitude of earthquakes, *M*, is proportional to the rock shear modulus, the rupture area and the mean shear slip (Stekettee, 1958). Thus, the magnitude is controlled by the pressurized area of the fault. In this way, the orientation of the injection well affects the magnitude of potential induced seismicity because ~~horizontal~~ wells that are parallel to strata pressurize a larger area than vertical wells, but take a longer time to exceed the critical pressure at the fault (Rinaldi et al., 2015). The magnitude of induced seismic events is also controlled by the brittleness

of the fault. While brittle faults with a slip-weakening behavior can induce large earthquakes (M>4) (Rutqvist et al., 2016), ductile faults give rise to progressive ruptures in which shear slip progressively accumulates, giving rise to aseismic slip or a swarm-like seismic activity (Vilarrasa et al., 2017b).

Another aspect that controls fault stability as a result of fluid injection is fault offset. Figure ~~7~~ 6a represents a typical scenario that can be encountered in a normal faulting stress regime setting, i.e., a steep fault in which the hanging wall has slid downwards with respect to the footwall. The fault is considered to have an offset equal to half of the storage formation thickness~~. The fault is composed by~~ and consists of a ~~low-permeable~~low permeability core (10^{-19} m^2) and ~~a~~ damage zones on ~~each side of~~ the core sides. ~~The p~~Properties of the damage zone depend on the material it is in contact with, becoming more permeable and less stiff than the intact rock as a result of fracturing (Table A2). Thus, the damage zone is of high permeability next to the storage formation, but of relatively low-permeability and high entry pressure next to the caprock and base rock ~~(Vilarrasa et al., 2016)~~. The caprock and base rock are more deformable than the storage formation (Table A3). The model is plane strain, with a constant vertical stress equal to 29.3 MPa acting on the top boundary and no displacement perpendicular to the other boundaries. The top of the storage formation in the hanging wall is placed at 1.5 km depth. CO_2 is injected at a constant mass flow rate of $2 \cdot 10^{-3}$ kg/s/m in the hanging wall, 1 km away from the fault, which leads to the pressurization of the storage formation.

~~After 1 year of injection, t~~The ~~P~~pressure ~~buildup in~~ the hanging wall of the storage formation, where CO_2 is being injected, ~~is of~~reaches increases by up to 10 MPa after 1 year of injection (Figure 6b). The ~~low-permeable~~low permeability fault core acts as a flow barrier, causing a rapid reservoir pressurization. This pressure increase expands the storage formation~~. In particular, the pressurized storage formation~~ pushinges the fault

towards the right-hand side. ~~This expansion~~While overpressurization is quite uniform ~~along the whole thickness of~~across the storage formation, the resistance to displacement~~but the deformation of the rock~~ on the other side of the fault depends on the stiffness of the ~~surrounding~~ rock. Since the storage formation is stiffer than the base rock, it absorbs~~contracts less than the base rock, but induces~~ larger stresses. As a result, the induced horizontal stresses in the in-plane direction are high where the storage formation is present on both sides of the fault, but it is low where the base rock is on the other side of the fault (Figure 6c).

These stress changes have a direct implication on~~f~~ fault stability. Figure ~~8~~ 7 displays the changes in the mobilized friction angle around the fault as a result of CO_2 injection. The most destabilized region is the lower half of the pressurized storage formation. Thus, an induced microseismic event would be initiated in that region of the fault, but slip ~~may become~~would be arrested below the caprock because fault stability improves within the damage zone of the storage formation on the side that is not pressurized. Thus, large magnitude induced events are unlikely in geological settings comparable to this simulated scenario. This difference in fault stability can be easily appreciated by representing Mohr circles in these zones (see inset in Figure ~~8~~7). Mohr circles shift to the left, getting close to failure, both at the top and bottom of the storage formation due to overpressure. But, ~~W~~while the deviatoric stress is maintained in the lower portion of the pressurized storage formation because the horizontal stress in the in-plane direction does not increase (see red circle in Figure ~~8~~7), the size of the Mohr circle decreases in the upper portion of the pressurized storage formation because of the increase in the horizontal stress in the in-plane direction where the storage formation is placed on both sides of the fault (see green circle in Figure ~~8~~7). This fault stability analysis highlights the fact that the accurate

assessment of fault stability changes in geologic carbon storage sites completely depend on proper site characterization.

~~7.~~9. CHARACTERIZATION TECHNIQUES

Site characterization has ~~traditionally~~ been traditionally considered as an activity that should be performed for ~~before a~~ project~~s~~ design and, therefore prior ~~enters in~~to operation. ~~Though necessary, such previous~~This kind of characterization tests are limited in time and ~~thus, they~~ can only characterize a small volume of rock around the injection well (Niemi et al., 2017). ~~However, t~~The size of the region affected by injection grows with the square root of time and since geologic carbon storage projects are planned to last several decades, full characterization can only be achieved by considering operation as a continuous characterization~~. This continuous characterization approach is~~, which we deem necessary to reduce ~~surface~~ uncertainty in predictive models of felt seismicity.

To assess whether CO_2 injection may induce felt seismicity, it is necessary to characterize the geological media in order to build a ~~conceptual~~ model of the site. ~~This~~ The conceptual model should include the geological layers (at least the caprock, potential secondary caprocks, the storage formation and subjacent layers down to the crystalline basement) and faults. Apart from the geometry, the hydraulic (permeability and porosity), thermal (thermal expansion coefficient, thermal conductivity and heat capacity) and geomechanical (stiffness and strength) properties are required. Additionally, the initial conditions should be determined, i.e., the fluid pressure profile (if pressure is hydrostatic or if there are pressure anomalies), the geothermal gradient, Gutenberg-Richter law and, especially for induced seismicity purposes, the stress state. Determining the magnitude and orientation (and their variability) of the stress tensor is critical, because fault stability

depends on the orientation of a given fault with respect to the stress tensor (Morris et al., 1996). ~~These~~ Hydraulic, thermal and geomechanical properties of each model layer~~rock~~ can be measured in the laboratory from core samples or in the field. While laboratory measurements allow a tight control of test conditions, they usually test only the rock matrix and fail to acknowledge scale effects associated to spatial variability of the above properties and the impact of discontinuities (e.g., Sanchez-Vila et al., 1996; Ledesma et al., 1996; Zhang et al., 2006; Cai et al., 2007). Thus, interpretation of field ~~measurements~~ tests leads to parameters that are~~is~~ more representative of operation conditions than laboratory experiments.~~.~~

To obtain estimates representative at the field scale of the hydraulic and geomechanical properties, Vilarrasa et al. (2013c) proposed a hydro-mechanical characterization test for CO_2 storage sites (Figure ~~9~~8). The test consists in injecting water at a high flow rate until microseismic events are induced. Ideally, the same brine from the storage formation should be injected to avoid geochemical reactions around the injection well that may alter rock properties. However, injecting brine would imply having a large ~~surface~~ facility on surface to store the brine from the storage formation that would have been pumped previously. The test has to be closely monitored with pressure, temperature, deformation and microseismicity monitoring. The hydraulic properties of the storage formation and caprock can be determined from the interpretation of injection as a hydraulic test (Cooper and Jacob, 1946; Hantush, 1956). If heterogeneities are present in the storage formation, their effect is only detectable for a limited period of time (Wheatcraft and Winterberg, 1985; Butler and Liu, 1993). For this reason, it is extremely important to continuously measure pore pressure changes during injection. As for the geomechanical properties of the storage formation and caprock, they can be derived from the interpretation of the vertical displacement at the top of the storage formation and the caprock. Additionally,

measuring the pressure evolution in the caprock, which undergoes a pressure drop in response of the pressure buildup in the storage formation (Hsieh, 1996), also gives information on the geomechanical properties. The magnitude of this reverse-water level fluctuation is inversely proportional to the storage formation stiffness (Vilarrasa et al., 2013c). Injection should be maintained until microseismic events are induced in the caprock, which gives an initial estimate of the maximum sustainable injection pressure that should not be exceeded during CO_2 injection to avoid compromising the caprock sealing capacity. This test is valuable to characterize storage sites in a pre-operation stage, but it should be complemented by a continuous site characterization during operation to characterize geological features present in the far field and reduce subsurface uncertainty.

An example of a continuous characterization technique that permits detecting and locating ~~low permeable~~low permeability faults is that proposed by Vilarrasa et al. (2017c). The idea is to use diagnostic plots, i.e., plots that include the fluid pressure evolution together with the derivative of the fluid pressure with respect to the logarithm of time (Bourdet et al., 1983; Renard et al., 2009), to detect faults significantly before (in the order of days) than if only fluid pressure evolution interpretation would be used (Figure ~~10a~~9a). This early identification of faults should permit decision makers to perform pressure management if necessary to mitigate future induced seismicity. This methodology only detects faults that are at least three orders of magnitude less permeable than the storage formation. However, this should not be a problem in terms of induced seismicity because faults that do not act as a flow barrier induce relatively small changes in fault stability (Vilarrasa et al., 2016). ~~Low permeable~~Low permeability faults generate an additional pressure ~~buildup~~ increase that differs from the expected pressure evolution in an aquifer that would not contain that fault. Thus, by comparing the measured pressure evolution, and its derivative with respect to the logarithm of time, with the predicted one,

~~low-permeable~~low permeability faults can be detected. This additional pressurization also affects the CO_2 dynamics because CO_2 is pushed away from the direction of the fault, leading to an asymmetric CO_2 plume (Figure ~~10b~~9b). Such asymmetry could be detected at monitoring wells, suggesting the presence of a low permeability fault, but it could also be due to reservoir heterogeneity (Chen et al., 2014). Once a fault is detected and located from the interpretation of pressure evolution (Figures 9c and 9d), it should be incorporated into the conceptual model of the site. Additional characterization techniques may be necessary to obtain a precise information on the detected faults. Then, field measurements should be compared with the updated conceptual model, which will permit identifying and locating new faults (Figure ~~10c~~9c) from the determination of the divergence time and the use of type curves (Figure ~~10d~~9d).

These characterization techniques entail a number of challenges. To begin with, the drilling of a network of monitoring wells is not yet ~~a~~ common practice ~~yet~~. Additionally, monitoring techniques also present challenges. Pressure is usually measured at the well-head, but calculating the bottom-hole pressure from the well-head pressure is not straightforward given the non-linearities of the injected fluid, especially for CO_2 injection (e.g., Lu and Connell, 2014). Unfortunately, pressure measurements in wells different than the injection well are almost inexistent. Temperature measurements receive even less attention because thermal effects are usually neglected. As for deformation measurements, ground surface can be measured with InSAR data, but for characterization tests that last a few days, the deformation of the ground may not be detectable given the great depths of suitable storage formations. Thus, deformation should be measured at depth within the boreholes. These measurements pose the question of whether the measured deformation refers to that of the rock or to that of the well. Since the casing of wells is stiffer than rock, the rock may deform more than the well and sliding could even

occur between the rock and the cement surrounding the well casing, making accurate measurements difficult. Fiber optics may solve part of these monitoring challenges, but the way how this monitoring should be performed is still not crystal clear for the moment. As far as microseismicity monitoring is concerned, arrays of geophones should be placed at depth. Otherwise, the signal-to-noise ratio is too high, which complicates detecting microseismic events. Additionally, multi-sensor arrays with a wide aperture coverage are necessary to accurately locate the events. Despite the existing challenges, ~~S~~such continuous characterization techniques are needed in order to minimize the risk of inducing seismicity in geologic carbon storage projects.

~~8.~~10. MINIMIZING THE RISK OF INDUCING FELT SEISMICITY

The issues discussed in the previous sections make it apparent that it is possible ~~T~~to effectively minimize the risk of inducing ~~large~~ earthquakes that are sufficiently large to be felt on the ground surface and may damage structures. We propose here a workflow consisting of~~,~~ the following steps ~~should be followed~~:

1) performing a detailed initial site characterization, with especial emphasis on the geological formations relevant to the site (at least of the storage formation, the caprock, ~~and~~ base rock and faults), including the determination of:
   - ~~the~~ geomechanical properties (Young's modulus, Poisson ratio, cohesion and friction angle) ~~of the geological formations relevant to the site (at least of the storage formation, the caprock and base rock)~~;
   - ~~the~~ hydraulic properties (permeability and porosity) ~~of the geological formations relevant to the site (at least of the storage formation, the caprock and base rock)~~;

- ~~the~~ thermal properties (thermal expansion coefficient, thermal conductivity and heat capacity) ~~of the geological formations relevant to the site (at least of the storage formation, the caprock and base rock)~~;
- the seismic velocities v_p and v_s from the surface to the crystalline basement. An accurate determination of these velocities is important not only for proper interpretation of geophysics, but also to locate the hypocenters of the induced seismicity with precision;
- the baseline of natural seismicity to establish the initial *a* and *b* values of the Gutenberg-Richter law in order to ~~discriminate~~ distinguish induced from natural seismicity;
- the initial pressure, temperature and stresses profiles with depth from the surface to the crystalline basement. The determination of the stress state is particularly important to perform a fault stability analysis of the identified faults and determining the strike and dip of critically oriented faults;
- characteristics of geological formations and faults and their location and orientation through 3D seismic data;

2) putting in place proper monitoring for performing continuous characterization, including:

- an array of geophones at depth to measure and locate induced microseismicity;
- a network of geophones on surface or in shallow wells with adequate spatial distribution, covering the whole footprint of the storage site to accurately locate induced seismicity. Induced events should be located in quasi-real time, together with their focal mechanisms to detect potentially unidentified faults that may induce large earthquakes. Inversion of the stress tensor is also important to detect possible local rotations of the stress tensor (Martinez-Garzon et al., 2013, 2014),

which could be induced by pressure ~~buildup~~increase, cooling and/or shear slip stress transfer (De Simone et al., 2017a). This seismic continuous characterization is particularly important when CO_2 is injected in the basal aquifer (Verdon, 2014; Will et al., 2016);

- monitoring wells measuring pressure, temperature and CO_2 saturation in the storage formation, caprock and secondary aquifer above the storage formation. Monitoring in secondary aquifers is useful for detecting brine and CO_2 leakage (e.g., Chabora and Benson, 2009; Zeidouni et al., 2014). Pressure measurements ~~can be used~~are necessary for ~~a~~ continuous characterization techniques as the one described in Section ~~7~~9;

3) carrying out pressure management:

- ~~based on the thermo-hydro-mechanical-seismic (THMS) monitoring and characterization, predictive models of induced seismicity that consider coupled THMS processes should be applied to identify the injection scenario that minimizes future induced seismicity. The continuous characterization will permit updating the fault stability analysis by incorporating newly detected faults. The range (taking into account the uncertainty on faults properties) of pressure buildup that makes faults become critically oriented for shear failure can be determined from the initial stress state, the strike and dip of faults, and the stress changes induced by CO_2 injection. Pressure management should be applied to avoid exceeded hazardous levels of pressure buildup around faults. To limit pressure, the injection rate may need to be lowered or pressure may need to be released in the vicinity of critically oriented faults (Birkholzer et al., 2012);~~
- storage alternatives to the conventional concept of storing CO_2 in deep saline aquifers may be used to have a better control on pressure ~~buildup~~increase. For

example, injection of CO_2 dissolved into brine is achieved by creating dipoles of wells in which brine is extracted from the storage formation and reinjected together with CO_2 in the same formation (Burton and Bryant, 2009; Jain and Bryant, 2011; Pool et al., 2013). The dipoles of wells limit pressure ~~buildup~~ increase and allow to have a better control on it. Similarly, geothermal energy production using CO_2 as a working fluid permits lowering pressure ~~buildup~~ increase and additionally extract geothermal energy (Randolph and Saar, 2011). Despite the promising potential of this technology, the only pilot site that has tried using CO_2 as a working fluid yielded a low performance because the thermosyphon that should permit circulating CO_2 with a negligible energy consumption ~~was not formed~~did not develop properly (Freifeld et al., 2016). Nevertheless, future research should enable a successful deployment of this technology~~;~~.

- in any case, predictive models of induced seismicity that consider coupled thermo-hydro-mechanical (THM) processes should be applied to identify the injection scenario that minimizes future induced seismicity. These predictive models should be based on the THM monitoring and continuous characterization. The continuous characterization will permit updating the fault stability analysis by incorporating newly detected faults (recall Figure 9). The range (taking into account the uncertainty on faults properties) of pressure increase that makes faults become critically stressed for shear failure can be determined from the initial stress state, the strike and dip of faults, and the stress changes induced by CO_2 injection. Pressure management should be applied to avoid exceeding hazardous levels of pressure increase around faults. To limit

pressure, the injection rate may need to be lowered or pressure may need to be released in the vicinity of critically oriented faults (Birkholzer et al., 2012).

~~9.~~11. CONCLUSIONS

Geologic carbon storage can successfully store gigaton~~e~~ scale of CO_2 at a low level of induced seismicity provided that proper site characterization, monitoring and pressure management are performed. There are several factors of geologic carbon storage that favor ~~the~~ a low induced seismicity risk. First, sedimentary formations where CO_2 is planned to be stored are, in general, not critically stressed, which permits generating a certain pressure ~~buildup~~ increase without reaching shear failure conditions. Special care should be taken if CO_2 is injected in the basal aquifer, because the crystalline basement is generally critically stressed and may contain unidentified faults that are critically oriented for shear slip. Additionally, CO_2 pressure evolution is relatively easy to control because pressure stabilizes after an initial sharp pressure ~~buildup~~increase, becoming practically constant afterwards. Despite this favorable pressure evolution, if ~~low-permeable~~low permeability faults are present, an additional pressure ~~buildup~~ increase may cause large stress changes ~~in~~ around the fault, leading to its reactivation. To prevent this situation, a detailed site characterization, both before the start of operation of projects and continuously during the whole operational stage, monitoring and pressure management should permit minimizing the risk of inducing large (felt) earthquakes.

APPENDIX

All the presented numerical simulations are performed with the fully coupled finite element code CODE_BRIGHT (Olivella et al., 1994; 1996), which solves non-isothermal two-phase flow in deformable porous media.

Table A1. Material properties used in the model of cold CO_2 injection shown in Figures 4 and 5

Property	Reservoir	Caprock and baserock
Permeability (m^2)	10^{-13}	10^{-18}
Relative water permeability (-)	S_l^3	S_l^6
Relative CO_2 permeability (-)	$(1-S_l)^3$	$(1-S_l)^6$
CO_2 entry pressure (MPa)	0.02	0.6
van Genuchten shape parameter (-)	0.8	0.5
Porosity (-)	0.15	0.01
Young's modulus (GPa)	10.5	5.0
Poisson ratio (-)	0.3	0.3
Cohesion (MPa)	0.01	0.01
Friction angle (-)	30.0	27.7
Thermal conductivity (W/m/K)	2.4	1.5
Solid specific heat capacity (J/kg/K)	874	874
Linear thermal expansion coefficient ($^oC^{-1}$)	10^{-5}	10^{-5}

S_l is the liquid saturation degree

Table A2. Properties of the materials forming the fault of the model shown in Figures 6 and 7

Property	Fault core	Damage zone reservoirs	Damage zone confinement layers	Damage zone basement
Permeability (m^2)	$1 \cdot 10^{-19}$	$2 \cdot 10^{-13}$	$1.5 \cdot 10^{-19}$	$1 \cdot 10^{-16}$
Relative water permeability (-)	S_l^6	S_l^3	S_l^6	S_l^4
Relative CO_2 permeability (-)	$(1-S_l)^6$	$(1-S_l)^3$	$(1-S_l)^6$	$(1-S_l)^4$
CO_2 entry pressure (MPa)	4.0	0.02	5.0	1.0
van Genuchten shape parameter (-)	0.3	0.8	0.3	0.5
Porosity (-)	0. 10	0.25	0.09	0.07
Young's modulus (GPa)	1.0	7.0	1.4	42.0
Poisson ratio (-)	0.30	0.35	0.42	0.30

S_l is the liquid saturation degree

Table A3. Material properties of the intact rock types included in the model shown in Figures 6 and 7

Property	Storage formation	Caprock	Base rock	Upper aquifer	Crystalline basement
Permeability (m^2)	$4 \cdot 10^{-14}$	$8 \cdot 10^{-20}$	$5 \cdot 10^{-20}$	$1 \cdot 10^{-14}$	$4 \cdot 10^{-20}$
Relative water permeability (-)	S_l^3	S_l^6	S_l^6	S_l^3	S_l^6
Relative CO_2 permeability (-)	$(1-S_l)^3$	$(1-S_l)^6$	$(1-S_l)^6$	$(1-S_l)^3$	$(1-S_l)^6$
CO_2 entry pressure (MPa)	0.02	10.0	10.0	0.20	12.0
van Genuchten shape parameter (-)	0.8	0.3	0.3	0.8	0.3

Porosity (-)	0.23	0.05	0.05	0.13	0.01
Young's modulus (GPa)	14.0	2.8	3.0	28.0	84.0
Poisson ratio (-)	0.31	0.40	0.39	0.21	0.18

S_l is the liquid saturation degree

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TABLES

Table 1. Stress state (maximum principal stress, σ_1, intermediate principal stress, σ_2, minimum principal stress, σ_3, and pore pressure, P) and mobilized friction coefficient (μ_{mob}) at several CO_2 injection sites

Site	Depth (m)	σ_1 (MPa)	σ_2 (MPa)	σ_3 (MPa)	P (MPa)	μ_{mob} (-)
In Salah, Algeria[1]	1800	49.9	44.5	30.8	18.2	0.48
Weyburn, Canada[2]	1450	34.0	26.0	22.0	14.5	0.50
Otway, Australia[3]	2000	58.0	44.0	31.0	8.6	0.41
Snøhvit, Norway[4]	2683	65.0	60.6	43.0	29.0	0.49
Tomakomai, Japan[5]	2352	53.8		43.8	33.7	0.35
St. Lawrence Lowland, Canada[6]	1200	48.0	30.7	24.6	11.8	0.54
Decatur, Illinois[7]	2130	98.0		50.6	21.9	0.51
Pohang, Korea[8]	775	18.2	15.1	13.8	7.6	0.27

References: [1] Morris et al. (2011), [2] White and Johnson (2009), [3] Nelson et al. (2006); Vidal-Gilbert et al. (2010), [4] Chiaramonte et al. (2013), [5] Kano et al. (2013), [6] Konstantinovskaya et al. (2012), [7] Bauer et al. (2016), [8] Lee et al. (2017)

FIGURES

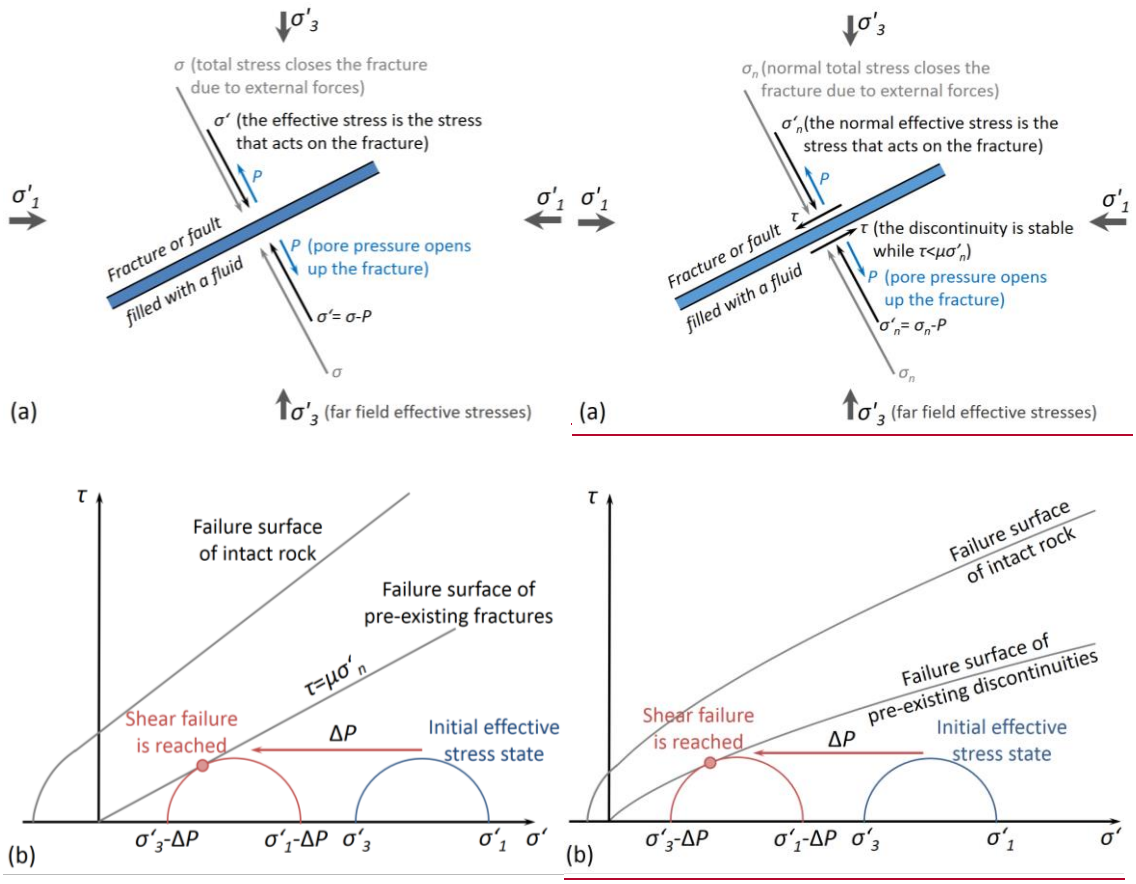


Figure 1: (a) Initial stress state of a fracture or fault of arbitrary orientation with respect to the far field effective stress and (b) Mohr circles showing how the reduction in effective stresses as a result of pressure buildup, ΔP, may induce shear failure in pre-existing discontinuities, i.e., fractures or faults. σ'_1 and σ'_3 are the maximum and minimum principal effective stresses, respectively, τ is tangential stress, σ'_n is normal effective stress to the fracture or fault, and μ is the friction coefficient. The failure surface has been plotted considering non-linear ~~fault strength~~failure criterion (Barton, 1976).

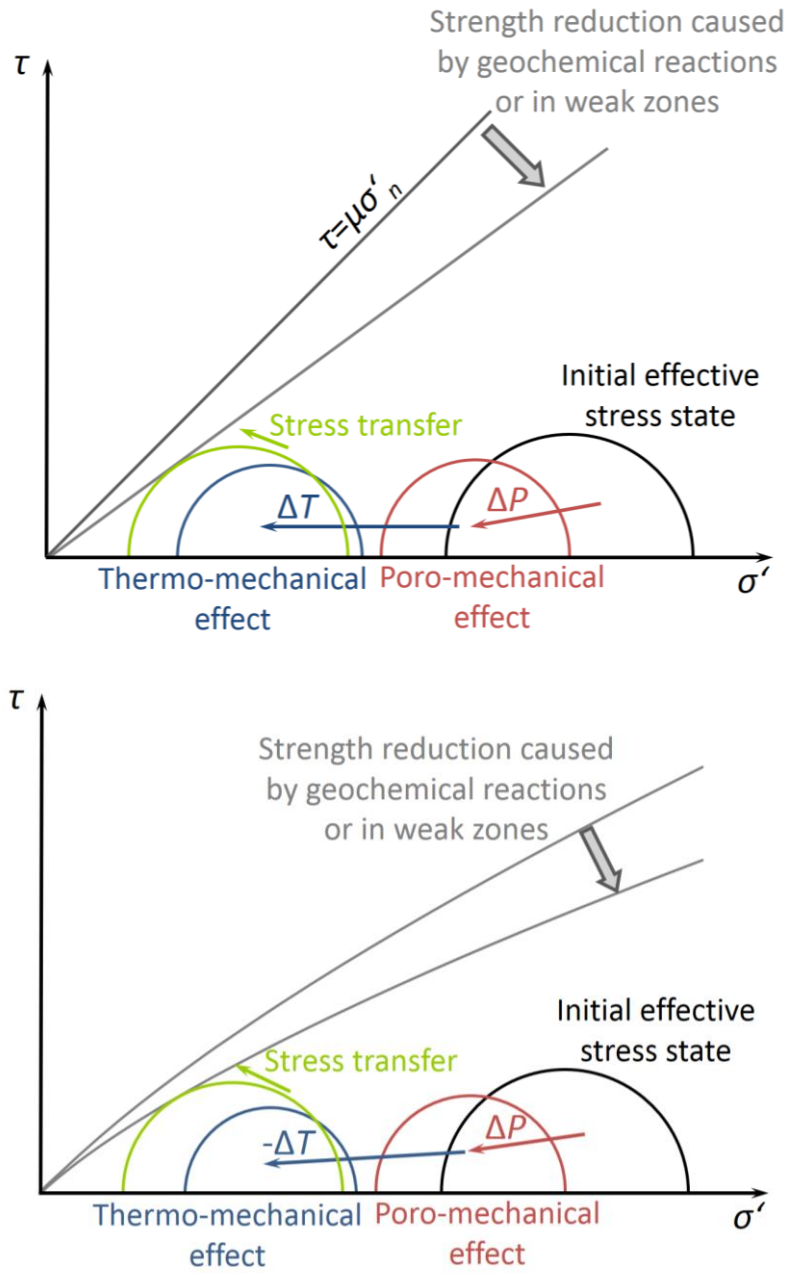
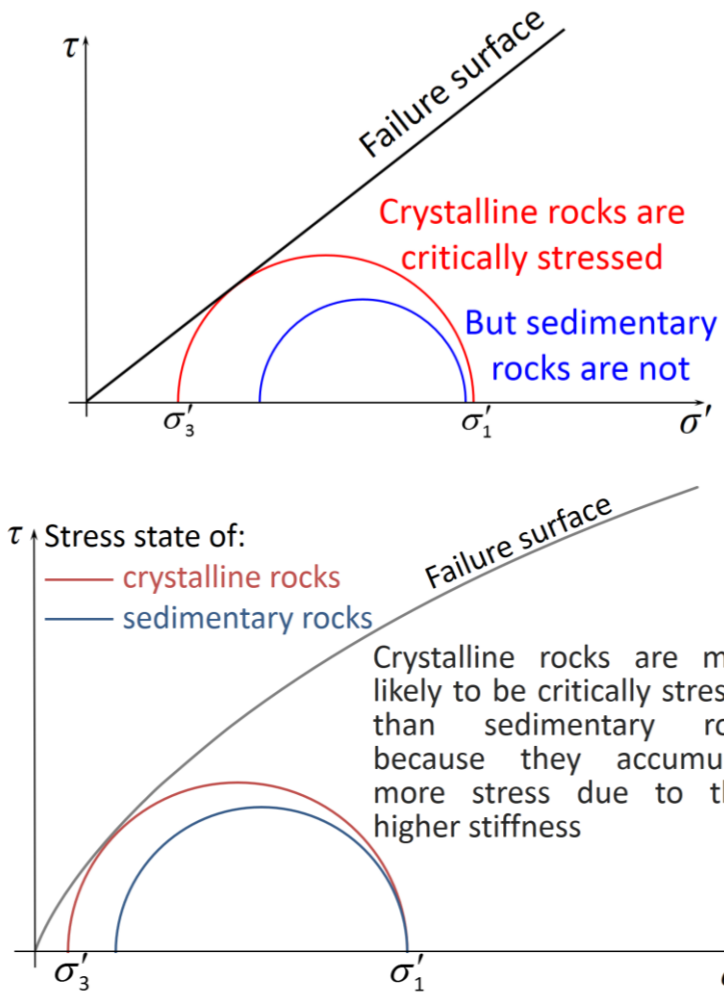


Figure 2: Schematic representation of several coupled effects on fracture/fault stability. Pressure buildup, ΔP, decreases the effective stresses and may cause~~s~~ poro-mechanical stresses that change the size of the Mohr circle; ~~temperature variations~~cooling, $-\Delta T$, induces thermal stress~~es~~ reduction; seismic and aseismic shear slip and interactions between geological layers with different rock properties produce total stress changes; and geochemical reactions may alter the strength of fractures and/or faults.



~~Figure 3: Stress state of crystalline and sedimentary rocks, showing that sedimentary rocks, which are the rocks where CO_2 will be stored, are usually not critically stressed.~~

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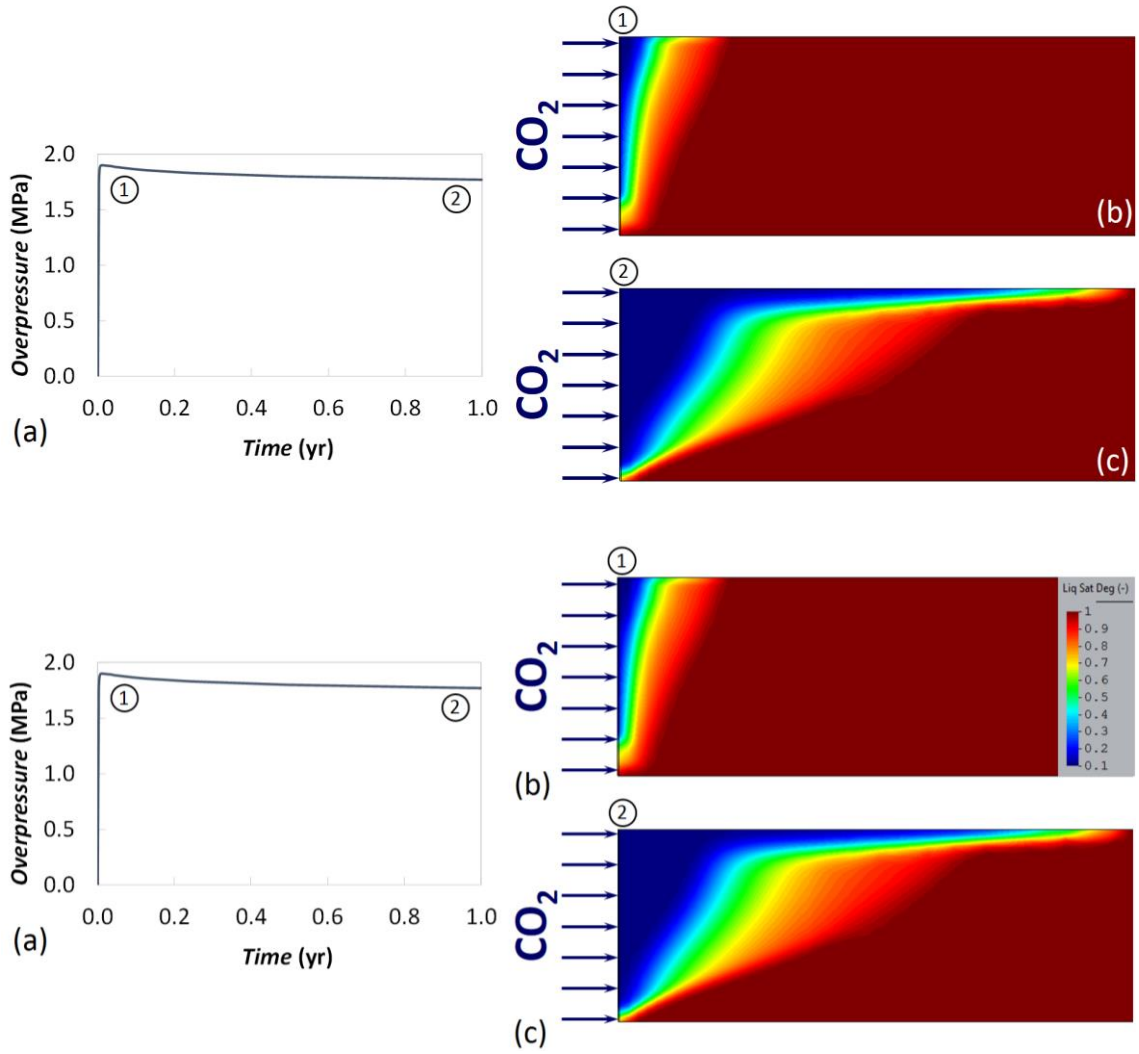

Figure ~~4~~3: (a) CO_2 ~~injection~~ pressure evolution when injecting 1 Mt/yr of CO_2 through a vertical well in a 100-m thick aquifer with an intrinsic permeability of 10^{-13} m^2 and a radius of 100 km, (b) ~~showing~~ the CO_2 plume shape at the beginning of injection, coinciding with the peak in injection pressure (see number 1 in (a)), and (c) the CO_2 plume once gravity override dominates and the capillary fringe has been developed, leading to a slight pressure drop (see number 2 in (a)). The color bar displaying the liquid saturation degree in (b) applies for both (b) and (c).

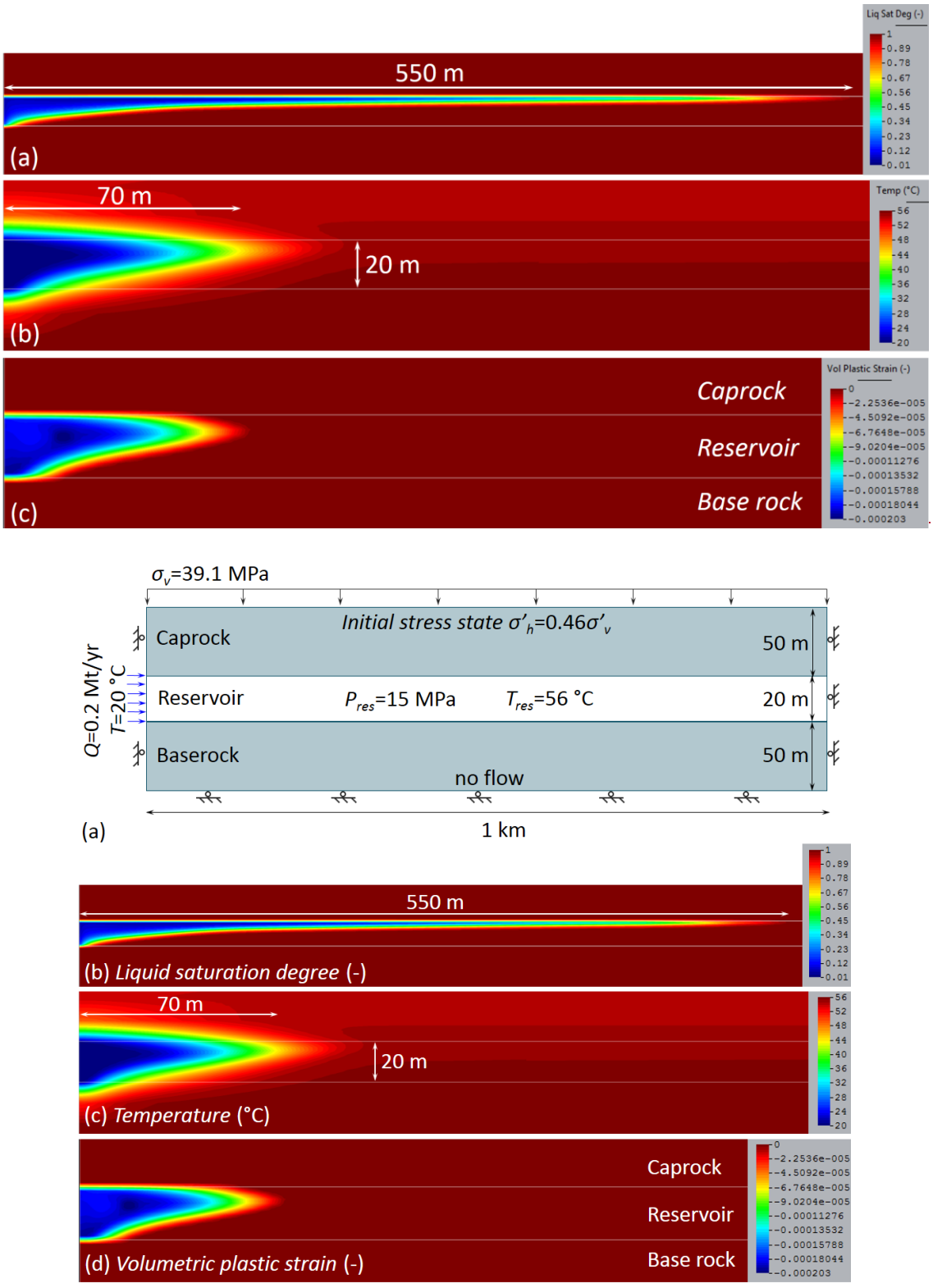

Figure ~~5~~4: (a) Model setup, (b~~a~~) l~~L~~iquid saturation degree, (c~~b~~) temperature distribution and (d~~c~~) volumetric plastic strain after 2 years of injecting ~~1~~ 0.2 Mt/yr of CO_2 at 20 ºC through a vertical well. While (~~b~~c) and (~~c~~d) are plotted at the same scale, (~~a~~b) is plotted at a smaller scale.

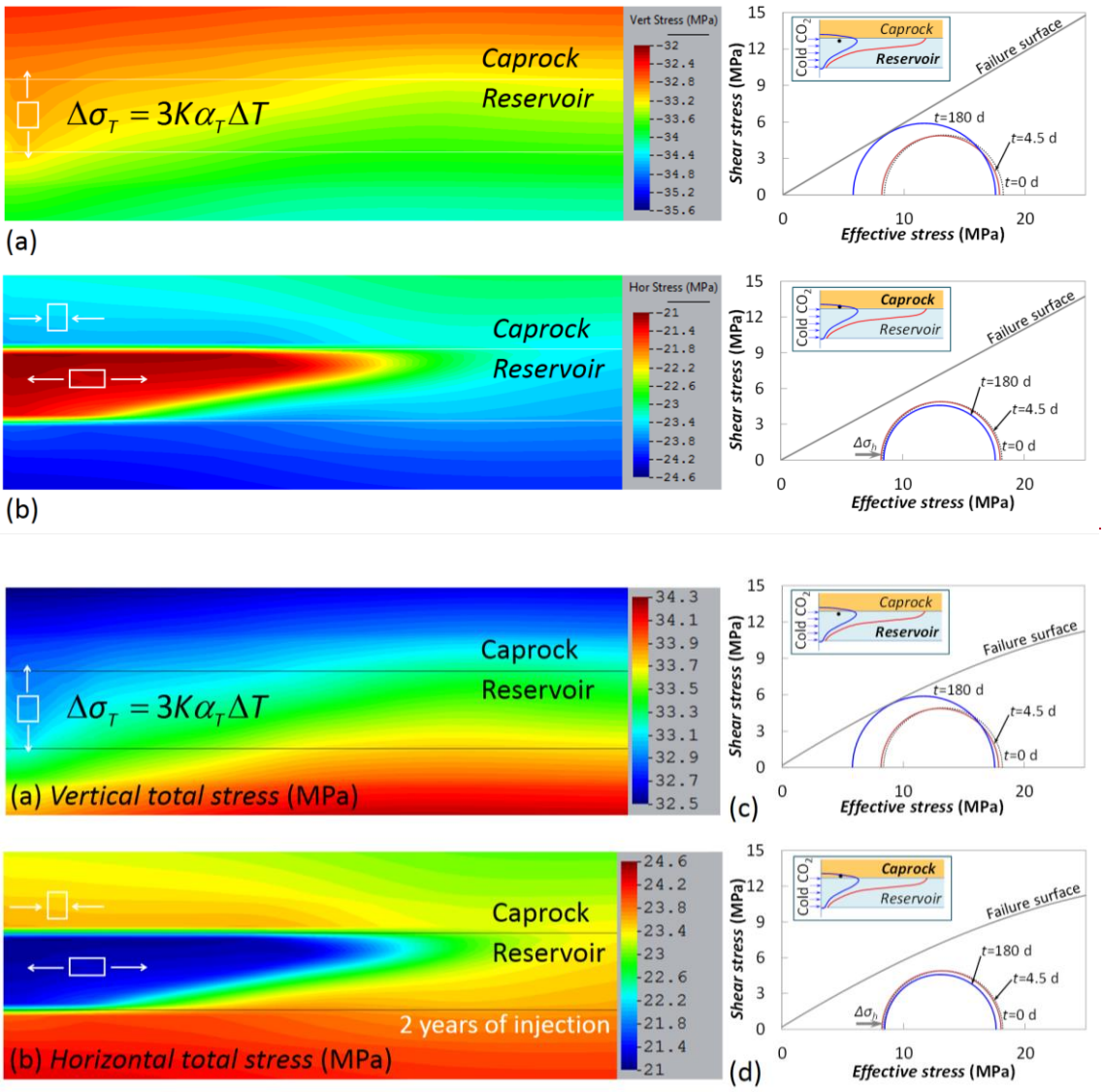

Figure 5~~6~~: Total stresses in the (a) vertical and (b) horizontal direction after ~~half a~~2 years of injecting ~~1~~ 0.2 Mt/yr of CO_2 at 20 ºC through a vertical well, indicating the sign of the induced stresses. Thermal stresses, $\Delta\sigma_T$, are proportional to the bulk modulus, K, the thermal expansion coefficient, α_T, and the temperature difference, ΔT. The changes in the Mohr circles at a point placed 25 m away from the injection well in (~~a~~c) the reservoir (2 m below the reservoir-caprock interface) and (~~b~~d) the caprock (2 m above the reservoir-caprock interface) are ~~is~~ also represented.

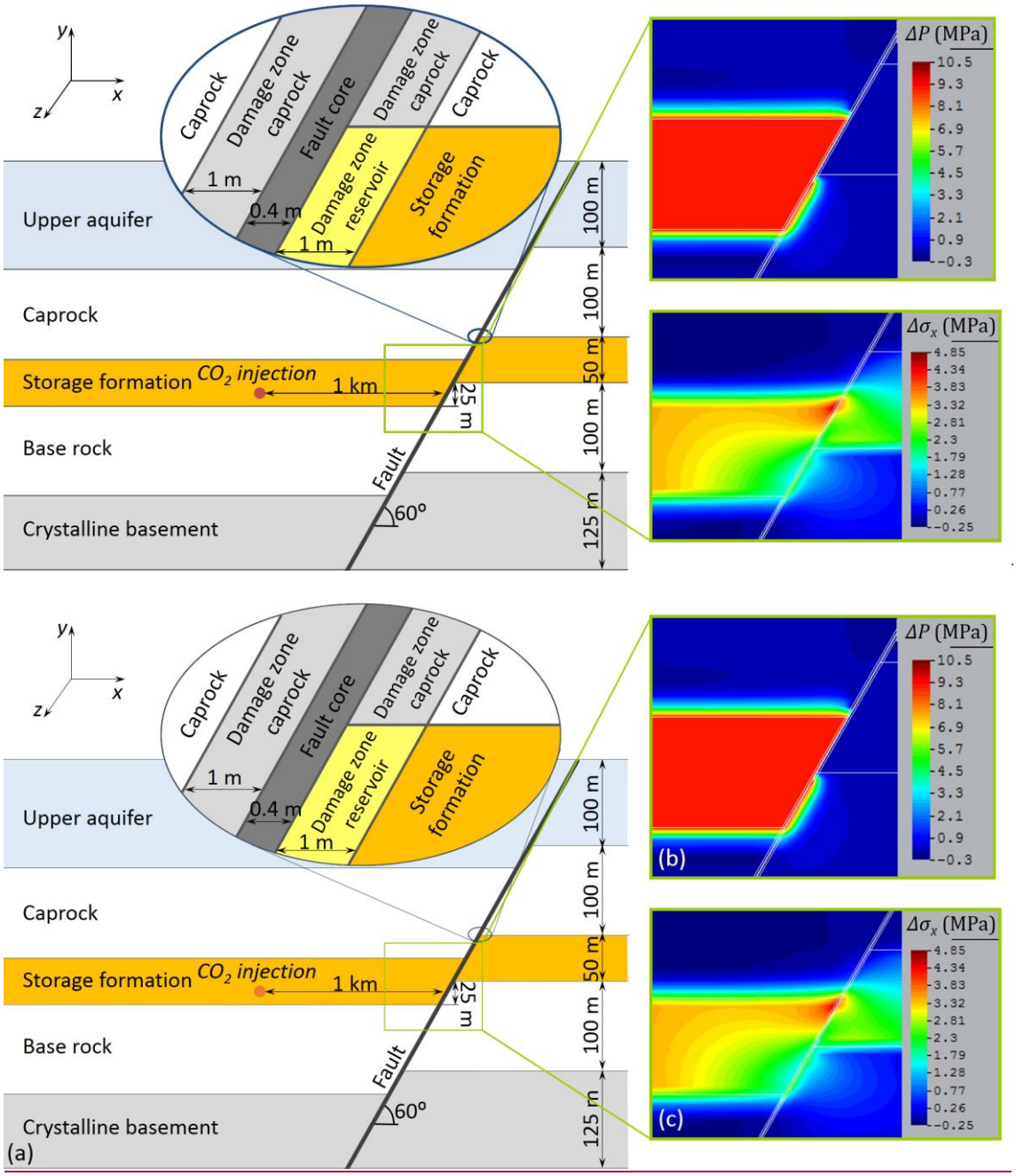

Figure ~~7~~6: (a) Geological setting in a normal faulting stress regime (plane strain model), including a ~~low-permeable~~low permeability fault that leads to (b) reservoir pressurization, ΔP, and (c) horizontal total stress changes in the in-plane direction, $\Delta\sigma_x$, when CO_2 is injected in the hanging wall at a rate of $2 \cdot 10^{-3}$ kg/s/m for 1 year.

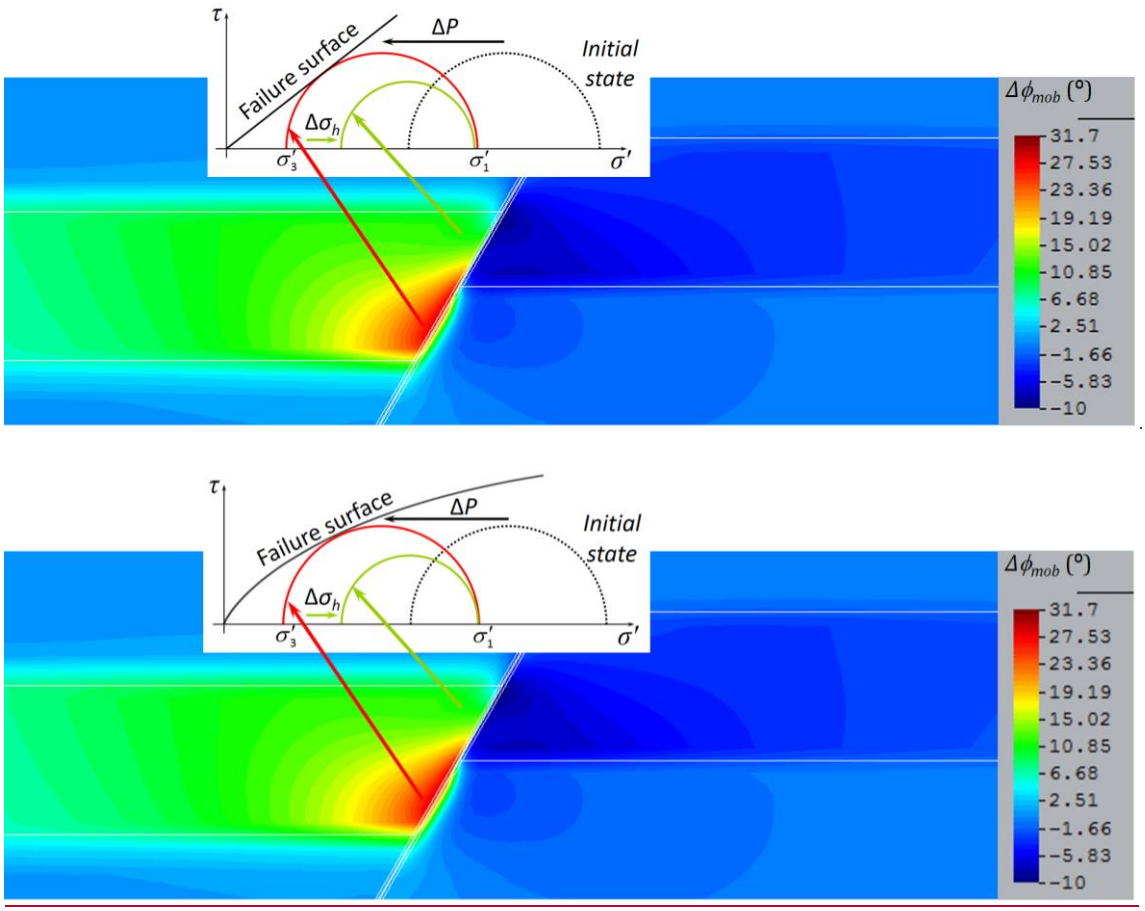

Figure ~~8~~7: Distribution of stability changes induced by the pressure and stress changes shown in Figure ~~7~~6, measured in terms of the mobilized friction angle changes, $\Delta\phi_{mob}$. The inset shows the Mohr circles before and after reservoir pressurization.

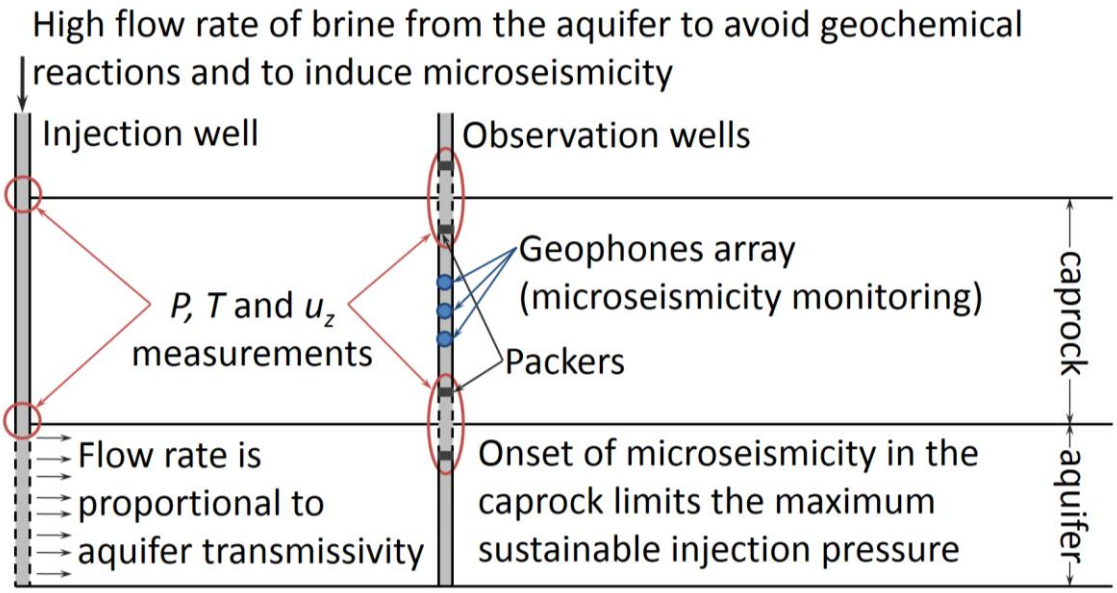

Figure ~~98~~8: Hydro-mechanical characterization test proposed by Vilarrasa et al. (2013c) to quantify the rock properties at the field scale and obtain an initial estimate of the maximum sustainable injection pressure. *P* refers to pressure, *T* to temperature and u_z to vertical displacement.

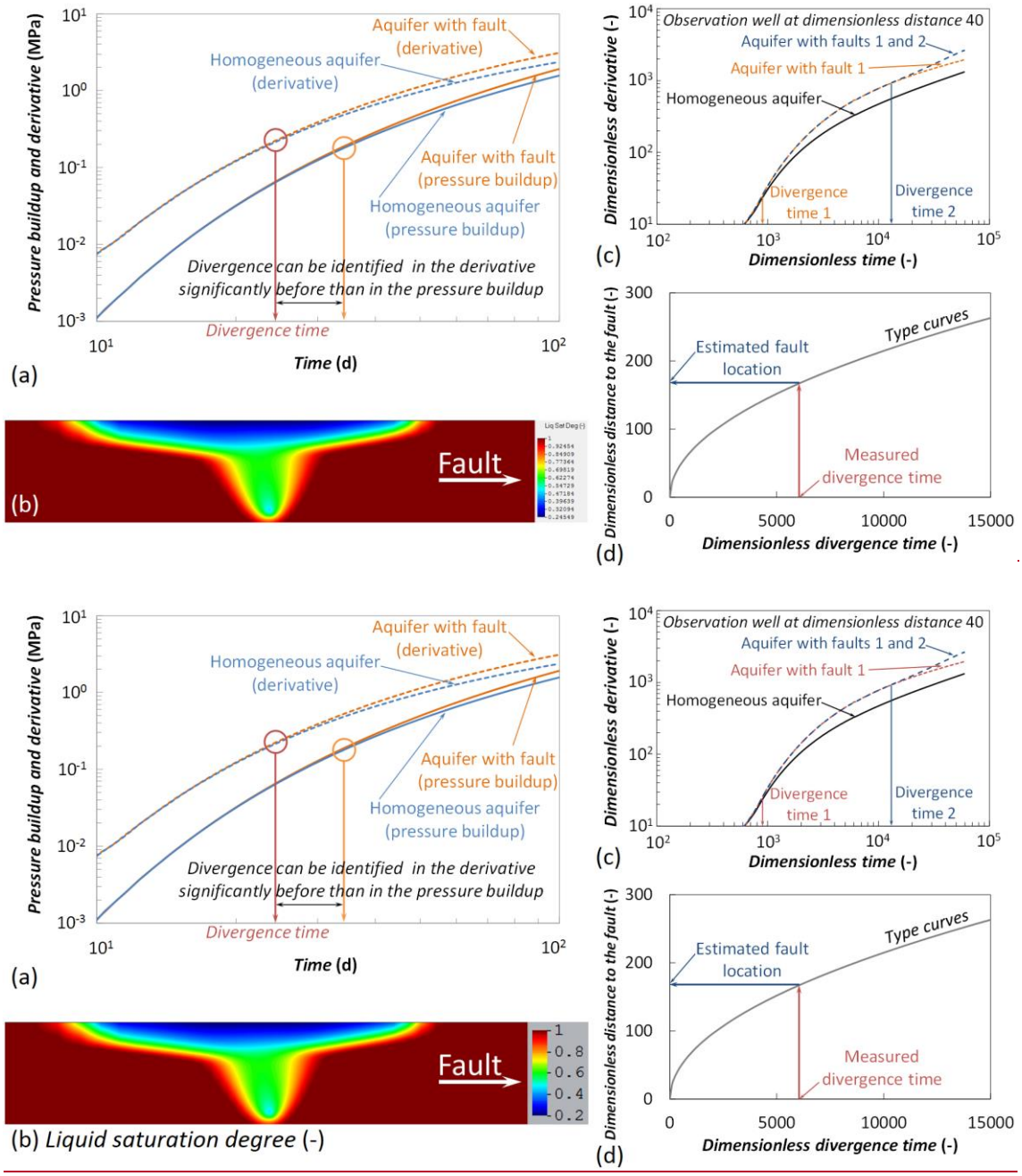

Figure ~~10~~9: (a) Concept of the continuous characterization technique proposed by Vilarrasa et al. (2017c) to detect and locate ~~low-permeable~~low permeability faults using diagnostic plots; (b) asymmetric CO_2 plume as a result of the additional pressurization caused by a low-permeability fault, which displaces CO_2 towards the opposite direction of the fault; (c) detection of multiple faults by updating the conceptual model of the site and comparing field measurements with predictive simulations; and (d) estimation of the

fault location from the measured divergence time in the derivative of the pressure evolution using type curves.