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Investigating stress path hysteresis in a CO_2 injection scenario using coupled geomechanical-fluid flow modelling

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Abstract

A successful CO_2 storage project will require large volumes of CO_2 to be injected into storage at industrial rates in a reliable and secure manner, the operators of the project must also be able to demonstrate the accuracy of modelling predictions for storage to both the regulators and public. Leakage from storage will compromise both the capacity estimates of the storage capacity, and the perceived security of the project even if the leakage is transient. Fluid induced fractures caused by injection of CO_2 above the fracture pressure of the formation will control the volume of CO_2 a storage reservoir can hold, and will control the rate of CO_2 injection; therefore the estimation of the pressure at which a formation will fracture is a key consideration in the modelling of a storage project. Field evidence of fracture pressures from reservoirs in the North Sea show evidence that the fracture pressure upon reinjection into a field is often lower than predicted by conventional approaches. This study presents a coupled geomechanical-fluid flow model modeling injection into a depleted field, the model exhibits hysteretic stress path behavior demonstrating a case of potential overestimation of fracture pressure. This study is the initial stage in a full sensitivity analysis of the material model parameters controlling stress path hysteresis including model geometry effects.

Keywords: Coupled modelling; geomechanics; hysteresis; stress path; numerical modelling; fracture pressure

1. Introduction

The risk of CO_2 leakage through fractures is one of the primary risks for secure containment of CO_2 in geological storage and is also a key control on the capacity and injectivity of any CO_2 storage formation,

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the generation of re-activation of fractures in a storage reservoir may have multiple causes, but one of the least widely researched is stress path hysteresis. The reservoir stress-path is the way in which stresses throughout the reservoir vary as a function of fluid pressure; the stress path controls the fracture pressure and thus leakage pressure in the reservoir. In the literature the stress path is generally discussed in terms of reservoir depletion scenarios, and the general assumption is that the stress path is non-hysteretic; in which case the fracture pressure of the reservoir and caprock should be easily calculable upon reinjection into the reservoir. However, there is little discussion of stress paths in terms of injection (particularly CO_2) in the literature, and the available field evidence from some fields indicates evidence of hysteretic stress paths in some situations.

1.1. Stress path hysteresis

The reservoir stress path is the change in the total stress field in a reservoir during depletion or injection; there are two aspects to the stress path in reservoirs that must be considered. Firstly, the reservoir stress path is often considered to be controlled by the minimum horizontal total stress changes resulting from pore pressure fluctuations, sometimes referred to as (oil field scale) pore-pressure/stress coupling [1]. Secondly, the reservoir stress path can be affected by the change in total vertical stress (usually assumed to be the weight of the overburden) during compaction and expansion of the reservoir resulting from stress arching. Stress arching occurs when the weight of the overburden is supported by the material at the sides of the reservoir (sideburden) rather than the reservoir itself, this has the effect of changing the total vertical stress [3].

It is common to represent the pore pressure changes in the subsurface in association with a constant total stress distribution, which leads to the familiar representation on a Mohr circle diagram of the stress state translating horizontally based on the magnitude of pore pressure change as in Figure 1 (a). However, as discussed by Hillis [1] over the shorter timescales under consideration in reservoir operations pore pressure/stress coupling is the more general case, in this case the total stress distribution is not constant and pore pressure reduction (hydrocarbon depletion) is associated with a reduction in the minimum horizontal total stress, this leads to an expansion of the Mohr circle which represents the development of deviatoric stresses, this is illustrated in Figure 1 (b) and (c). The extent to which stress arching occurs also affects the stress path in the reservoir, if stress arching occurs then the effective stress evolution in the reservoir is negligible, and stress changes mostly occur in the overburden [3].

Thus far the description of the stress path has been in terms of pore pressure reduction, i.e. depletion, and this is the case for much of the literature (e.g. Segura et al, Hillis) the implication in the literature is that injection after depletion would follow a non-hysteretic path and that pore pressure increase should return the reservoir back to the initial stress state before production. However, there is little evidence to support this case in the literature, in fact most field evidences tends to suggest that upon re-injection into a reservoir the stress path follows a hysteretic path [4, 5], causing the Mohr circle representation to translate towards the tensile region, but without a reduction in deviatoric stress, this increases the risk of failure, and can be illustrated schematically with the Mohr circle representation in Figure 1(d).

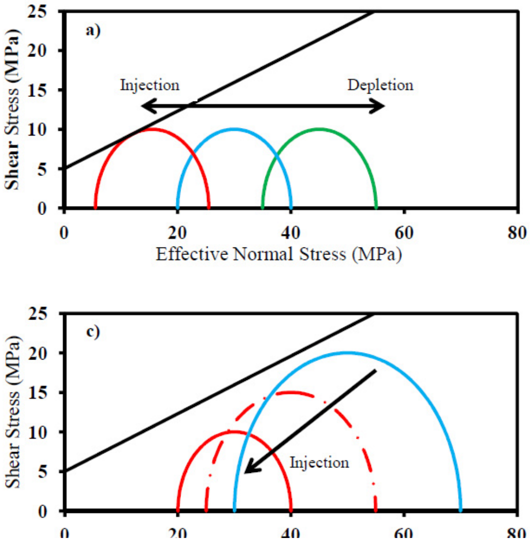

Figure 1 Based on [1](a) Mohr circle evolution with pore pressure with no change in total stress distribution. (b) and (c) Mohr circle evolution with pore pressure reduction and increase due to field scale pore pressure/stress coupling. Deviatoric stresses are generated due to pore pressure decrease, and are recovered upon reinjection of fluids. (d) Mohr circle evolution due to stress path hysteresis, deviatoric stress are generated due to depletion of pore fluid, deviatoric stresses are only partially recovered during fluid injection which leads to Mohr circle translation towards failure.

1.2. Field Evidence

The most significant piece of work from the literature relating to hysteretic effects in the stress path evolution is that of Santarelli, Tronvoll et al. [4] and the extension of this work by Santarelli, Havmøller et al. [5].

The work relates to injection operations in an oil field complex in the North Sea, where fracture pressures, a function of minimum horizontal stress, were measured during re-injection into the field after depletion. During re-injection it would be expected that an increase in the pore pressure in the field would lead to a reversal of the decrease in total horizontal stress, this would lead to a reduction in the effective horizontal stress, and the Mohr circle would indicate a reduction in differential stress. In theory this would not lead to failure as the Mohr circle would move to the left, but also decrease in size, approximately parallel to the failure envelope. Observations of fracture pressure from these studies show that upon pressurization the fracture pressure, a proxy of total horizontal stress, did not increase, this suggests that as pore pressure increases the effective horizontal stress would change (decrease) at a higher rate than on depletion, and differential stress would not be reduced [4, 5].

On a Mohr circle representation of this state, the circle would undergo translation rather than shrinkage and would meet the failure criterion at lower pore pressures than predicted from the existing theory, this would indicate lower fracture pressures than predicted upon reservoir re-pressurization (as in Figure 1 (d)). Santarelli, Havmøller et al, also discuss similar evidence from the Ekofisk field, first presented by [6, 7] and another unspecified North Sea field which supports their initial observations, they also suggest that there is no published data that contradicts the behavior they have observed in comparable depletion/injection scenarios.

Cleary this situation is highly applicable to carbon capture and storage scenarios, where the majority of early storage reservoirs are likely to be depleted oil and gas reservoirs, prediction of the correct fracture pressure during injection will control the final volume of CO_2 that can be injected, and the rate that injection can occur safely, and will be a critical parameter in planning CO_2 storage projects. This work attempts to simulate stress path hysteresis using a coupled geomechanical-fluid flow model of a generic reservoir, in order to perform a sensitivity analysis on the parameters controlling stress path hysteresis. The ability to determine the propensity for stress path hysteresis will improve the prediction of fracture pressures during injection of CO_2 and improve the accuracy of injection simulations.

2. Modelling Methodology

2.1. Modelling workflow

Initial work on stress path hysteresis has been carried out using coupled methodologies as part of the IPEGG (Integrated Petroleum Engineering, Geophysics and Geomechanics) JIP undertaken by the University of Leeds, the University of Bristol and Rockfield Software Limited, (sponsored by BG group, BP, Eni and StatoilHydro), for example Segura, Fisher et al. [3] examined the effect of reservoir geometry and material properties on reservoir stress path. The coupled approach used in this study was developed and tested extensively as part of the IPEGG project for production related problems, and has been adopted for use in CO2 injection studies.

The coupling technique used is an explicitly or iteratively coupled scheme using a 2-way algorithm to pass information between the fluid flow simulator and the Elfen Geomechanical Software Suite (Rockfield Software Ltd.). The reservoir model used for the study is a simple sandstone graben structure surrounded by a bounding shale geomechanical model developed as part of the IPEGG project (e.g. [8]), the geomechanical reservoir rock properties used represent a soft rock, typical of many reservoirs in the North Sea, and likely to be similar to the reservoirs discussed by Santarelli, Tronvoll et al [4] and Santarelli, Havmøller et al. [5]. The geomechanical model uses the SR3 model which is a modified version of the critical state Cam-Clay model, and thus it is particularly suitable for modelling soft rocks, this is especially appropriate for the work on stress path hysteresis and temperature coupling, as the main field observations of these effects arise in soft rock reservoirs in the North Sea. The SR3 model is capable of predicting pressure dependent rock deformation associated with volume and shape change, and can account for strain hardening and strain softening (residual strength) behavior, and non-linear dependence of volumetric strain on effective mean stress. The SR3 model is described more fully in Crook et al 2006 and Angus et al 2010 [8, 9].

Current work is focusing on carrying out a full sensitivity analysis of the parameters of the SR3 model in relation to stress path hysteresis for a production-injection cycle, this work is based on an initial study of a limited number of parameters by Segura, Skachkov et al. [2]. A further aim of the study is to include an

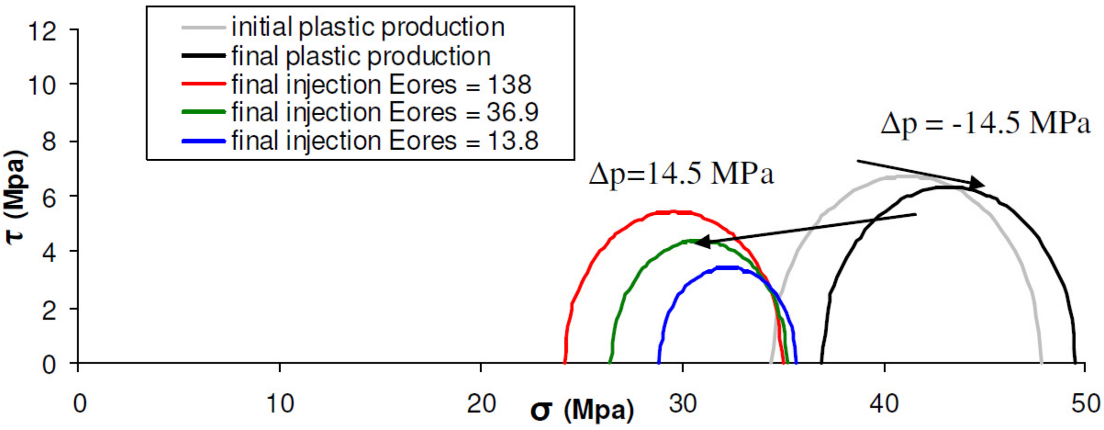

Figure 2 - Initial stress path hysteresis results from the IPEGG project, investigating stress path hysteresis in simple rectangular reservoirs. A production-injection scenario was investigated, and a sensitivity analysis performed on the reservoir stiffness. The results show effective stresses (incorrectly labelled on original diagram) on the Mohr circle, and show translational behaviour of the Mohr circle for a pressure depletion and re-injection of +/- 14.5 MPa, the scenario involved significant stress arching and the case with the stiffest reservoir exhibited the largest hysteresis [2].

analysis of the impact of production (and injection) induced reservoir temperature changes on stress path using temperature coupling in the model. Figure 2 shows initial results from Segura, Skachkov et al. [2] for an plastic loading (production) and elastic unloading (injection) cycle demonstrating stress path hysteresis.

2.2. Model geometry and modeling scenario

The model consists of a sandstone reservoir at depth, bounded by a shale overburden, sideburden and underburden, the reservoir is faulted and forms a graben structure with three compartments. The faults persist in the overburden and underburden and are represented by contact elements in the finite element model, the discretization of geomechanical model and the reservoir model are shown in Figure 3.

The geomechanical model is 18.6 km x 9.3 km x 3.72 km (from the surface), the reservoir is 76 m thick and located at 3.048 km depth, the horizontal dimensions of the reservoir are 7 km x 3.5 km. A second model with the reservoir 2.048 km from the surface has also been constructed to investigate surface deformation and stress path hysteresis.

Four coupled flow–geomechanical scenarios are used in this model, representing the structural/fault parameters that may be varied. The fault transmissibility is altered to model sealing and non-sealing flow behavior across the fault, the fault transmissibility multiplier set at a high value - 0.98 (non-sealing) and value close to zero - 0.00001 (sealing). The friction between the contact elements on the fault is also varied to represent faults that are reactivated/no-reactivated. The friction coefficient between the contact elements on the fault set to Mohr-Coulomb friction and the coefficient of friction is set at a high value - μ =0.750 to restrict movement and a low value - μ=0.375 to promote fault movement..

For the depletion-reinjection scenario the CO_2 injection is rate controlled, with a maximum bottom hole pressure equal to the initial reservoir pressure, so that pre-depletion and post-injection states are comparable in terms of pressure. For this study the injection well was placed in one of the compartments, and is a vertical well, the reservoir is depleted from 30 MPa to 0.5 MPa, and then re-injected to the same pressure, the cycle takes ~20 years.

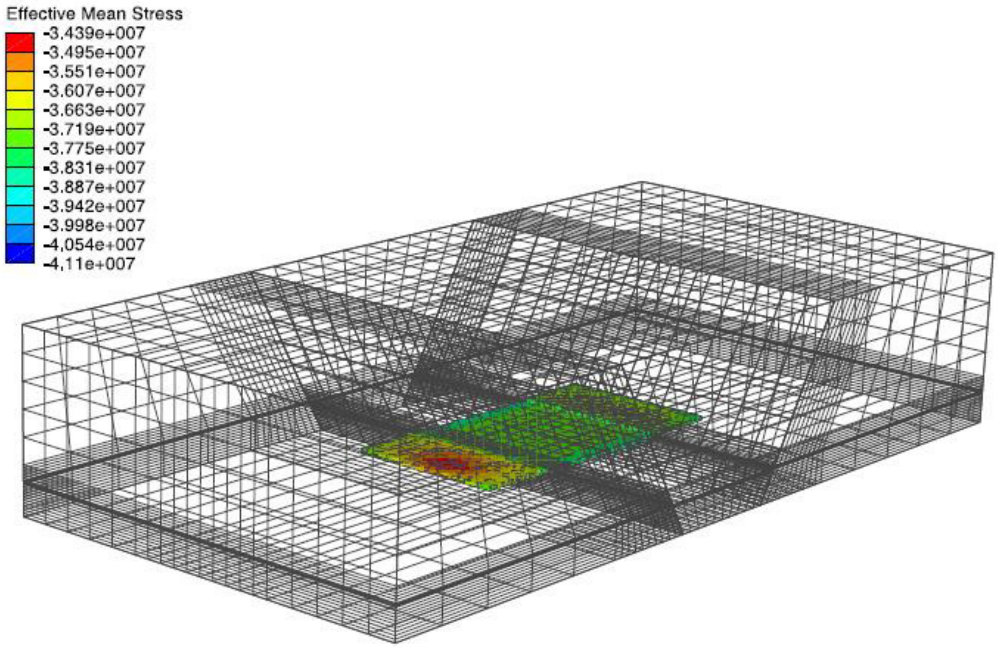

Figure 3 - Geomechanical grid showing position of reservoir model and bounding geomechanical model. Model shows region of increased pressure in reservoir model for injection stage of the modelling.

3. Results and Discussion

Initial results for the high transmissibility, low fault friction coefficient are presented in Figure 4, as in the case of the previous work from the IPEGG project results were analyzed for the cell located at the well injection point, and this location is represented in the figure.

The diagram shows Mohr circles for the maximum and minimum principal effective stresses, the green circles represent initial (light green) and depleted (dark green) stages of the scenario, and the injection stage (light to dark red). The results show a similar trend to those in Figure 2, depletion from the initial state follows predicted behavior based on field scale pore pressure coupling, as shown in Figure 1 (b). Upon reinjection into the reservoir the Mohr circle it would be expected that the Mohr circle would shrink back to the original initial depletion state, however in this case there is clear evidence of stress path hysteresis as illustrated in Figure 1 (d). The circles representing the material state during re-injection show growth and significant translation compared to the initial depletion state, at a lower fluid injection pressure than the initial reservoir state ~14 MPa the shear stresses are already greater than those prior to depletion at similar horizontal stresses, and upon reaching the final injection pressure the Mohr circle has shown significant translation. In this case the reservoir modeled was unrealistically stiff and matches the case with the stiffest reservoir in Figure 2 (138 GPa), in this case the ratio of horizontal stress to pore pressure will be low and will lead to greater Mohr circle translation [2].

These initial results show that the behavior modeled in the previous study with simple reservoirs can be replicated in a more complex geometry, the results show that in this case the stress path behavior and the consequent fracture pressure predictions may deviate from classical predictions and could lead to a situation where CO_2 could be injected at pressures greater than the fracture pressure due to overestimation of allowable fracture pressures. This situation would lead to a reduction in storage capacity as fluid injection would have to be curtailed at a lower than predicted pressure, and injection rates would also have to be revised in order not to exceed the fracture pressure at the wellbore when injecting CO_2 in extreme cases this could require extra wells to be drilled to reduce the injection pressure – a significant project cost.

In this study there are numerous parameters that could affect the stress path, these include the material parameters input into the geomechanical model, the geometry of the model and the fault properties, the results presented here represent the initial stages of a full sensitivity analysis that will be carried out using a similar approach. The aim of the analysis is to determine the key parameters that control the stress path hysteresis behavior and determine potential causes for the observed behavior. In the review of the data relating to stress path hysteresis by Santarelli et al, 2008 a study on temperature of the injection fluids has also been included, and it is suggested that the injection of cold fluids into the reservoir may be a contributing factor to the observed stress path hysteresis [5]; work to incorporate the thermo-elastic stresses generated by temperature effects into the coupled geomechanical model is ongoing, and this will form another component of the sensitivity analysis.

4. Conclusions

This study has made a preliminary investigation of the potential for stress path hysteresis in CO_2 storage projects, the stress path hysteresis may lead to erroneous calculation of the fracture pressure of a reservoir which has the potential to compromise storage capacity calculations and injection rate targets, the potential for leakage from storage, however slight, also has the potential to impact upon public opinion which is likely to be a key factor in early demonstration projects.

Future work will focus on constraining the controlling parameters for stress path hysteresis, such as geometry and temperature effects, a future study after the initial sensitivity analysis will use a North Sea oil field to test the model in a realistic geometry with history matched production data.

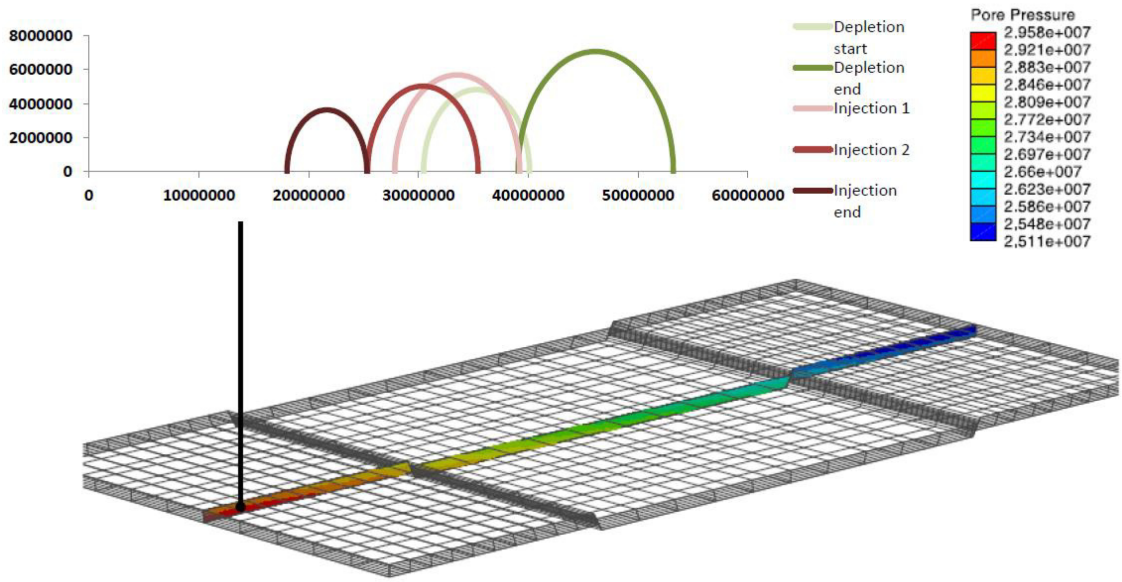

Figure 4 - Results from initial work analysing a depletion-reinjection cycle for the model with high fault transmissibility and low fault friction properties. Green Mohr circles represent the initial (light) and final (dark) depletion states, the red Mohr circles represent stages of injection, start (light) to end (dark). The model discretisation shows the location of the cell where the data was analysed, and the contours represent pore pressure.

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