Introduction

In the context of Carbon Capture and Storage (CCS) site appraisal procedures, the assessment of geomechanical risks associated with injection tests is important. Assessments can calculate injection pressure thresholds and guard against formation fracturing and solids production during fall-off tests or due to unplanned shut-in occurrences. A robust and field calibrated geomechanical model is the key component of risk evaluation for both injection tests and long-term injection phases. Common reservoir and wellbore integrity risks include induced tensile fracturing, cap rock integrity, and potential fracture and fault reactivation. The analysis involves assessing changes in rock mechanical properties and near-wellbore stresses triggered by temperature and pressure variations caused by water or carbon dioxide (CO_2) injection.

Formation solids are normally stationary during steady injection. However, rock failure and the consequent solids production can be initiated during shut-in due to transient flow effects such as back-flow or during fall-off tests. Nunez et al., 2010 conducted comprehensive data analyses and suggested that solids production, due to the phenomena of backflow, crossflow and water hammer effects, leads to major integrity problems in several injection wells. This is especially the case with solids and fines migration and accumulation inside the lower completion during sudden or prolonged well shut in. Hansen et al., 2005 reported initial injection problems due to sand influx in a CO_2 injection site. Problems were solved by re-perforation of the injection interval and installation of sand screens and gravel packs. Sand influx in injection wells results in high bottom hole injection pressures, diminished or loss of injectivity, screen plugging and erosion of downhole equipment.

Thermally induced fracturing is often observed during water injection, especially when there is a large temperature difference between the (cold) injection water and the (hot) reservoir. In such instances, the typical response is a sudden increase in injectivity after a significant period of stable injection because of induced fracturing (Svendsen et al., 1991). The reservoir rock shrinks due to cooling and eventually the minimum stress is reduced to a level below the injection pressure. This results in the creation of a fracture which provides a much larger contact area with the formation. This process is normally referred to as thermally induced fracturing (Fjær et al., 2008). During matrix (water) injectivity tests, the aim is to maintain the injection pressure below the tensile fracture initiation pressure and the minimum horizontal stress to reduce the risk of formation fracturing.

The CCS site is a monoclinal dipping saline aquifer, with the sandstones of the Early to Middle Jurassic Formation representing the primary storage reservoir target. The primary objectives of appraisal drilling and evaluation encompass a holistic characterisation of the storage site, with a focus on confirming storage reservoir and cap rock continuity and properties along with the assessment of matrix injectivity within the storage reservoir. This paper summarises the reservoir geomechanical studies to evaluate the sand influx and fracturing risks associated with an upcoming water injection test in the CCS appraisal well.

Method and/or Theory

A field calibrated geomechanical study has been conducted to assess the risk of formation fracturing and sanding during a water injection test planned for one of the appraisal wells. A geomechanical model was used to assess the sanding risks during fall-off tests, or due to unplanned shut-in occurrences, by estimating the critical drawdown. Additionally, thermally induced tensile fracture initiation pressures were assessed in order to establish injection pressure rate boundaries to reduce the risk of formation fracturing during the injection test.

Considering the temperature difference between the storage formation and the injection fluid, the cooling effects lead to a reduction of almost 15% in fracture initiation pressure (FIP). Notably, the FIP for perforations aligned with the maximum horizontal stress direction are lower than the minimum horizontal stress.

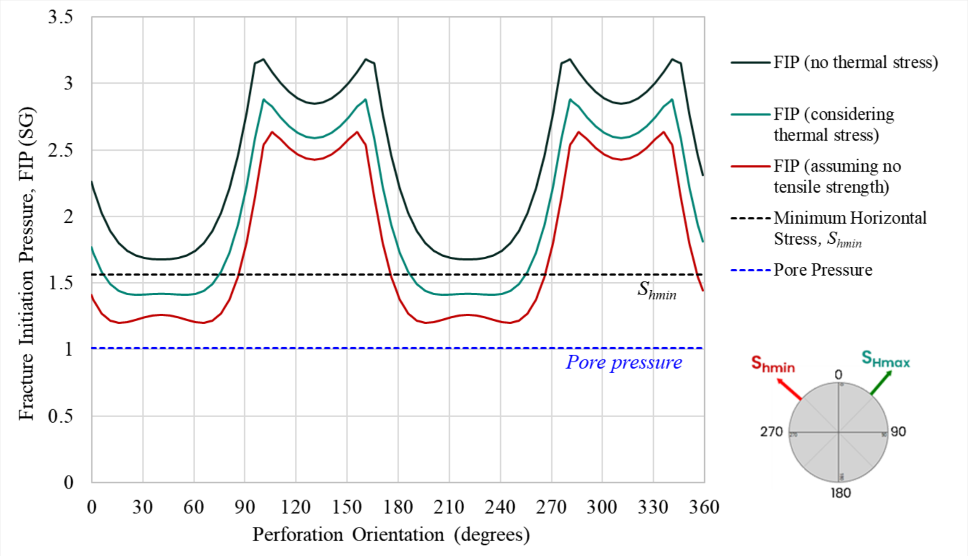

Figure 1 *Calculated fracture initiation pressure (FIP) at mid perforation injection depth in three different scenarios: (1) without thermal stress, (2) with thermal stress and (3) with thermal stress assuming zero tensile strength.*

Conclusions

This result signifies that:

- While injection pressures surpassing FIP might trigger tensile fracturing in specific perforations, fracture propagation from the wellbore remains unlikely if injection pressure remains below the minimum horizontal stress.
- The pressure requirements for current envisaged matrix injection rates fall below the estimated FIPs. Consequently, the risk of formation fracturing during the injection test is deemed low.
- The propensity of sanding during flowback, considering a range of rock weakening and thermal effects of water injection, is also found to be low.
- The study predicts that all perforations are poised to remain free of sand during flowbacks, even in the presence of applied or inadvertent drawdowns.

References

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