# Effect of injection strategy on Induced Seismicity risk during $CO_2$ storage

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# Effect of injection strategy on Induced Seismicity risk during $CO_2$ storage

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## INTRODUCTION

The Government of India has identified $CO_2$ storage in depleted oil and gas fields as the primary pathway to advance carbon capture and storage (CCS) in the country. Recently, Vishal et al. (2021) have estimated more than 2 Gt of effective $CO_2$ storage capacity in depleted oil fields in India.

However, numerous studies in $CO_2$ sequestration sites have shown that $CO_2$ injection can cause significant geomechanical changes, depending on the injection pressure and site-specific geomechanical conditions (Verma et al 2021). The importance of geomechanics has been highlighted in the past decade due to increased incidences of induced seismicity from $CO_2$ and other fluid injections globally (Vilarrasa et al., 2019). Even if significant seismicity is not observed, the fluid injection can induce local stress changes, which can permeate further away and can lead to geomechanical complications far from the injection area (Goebel and Brodsky, 2018).

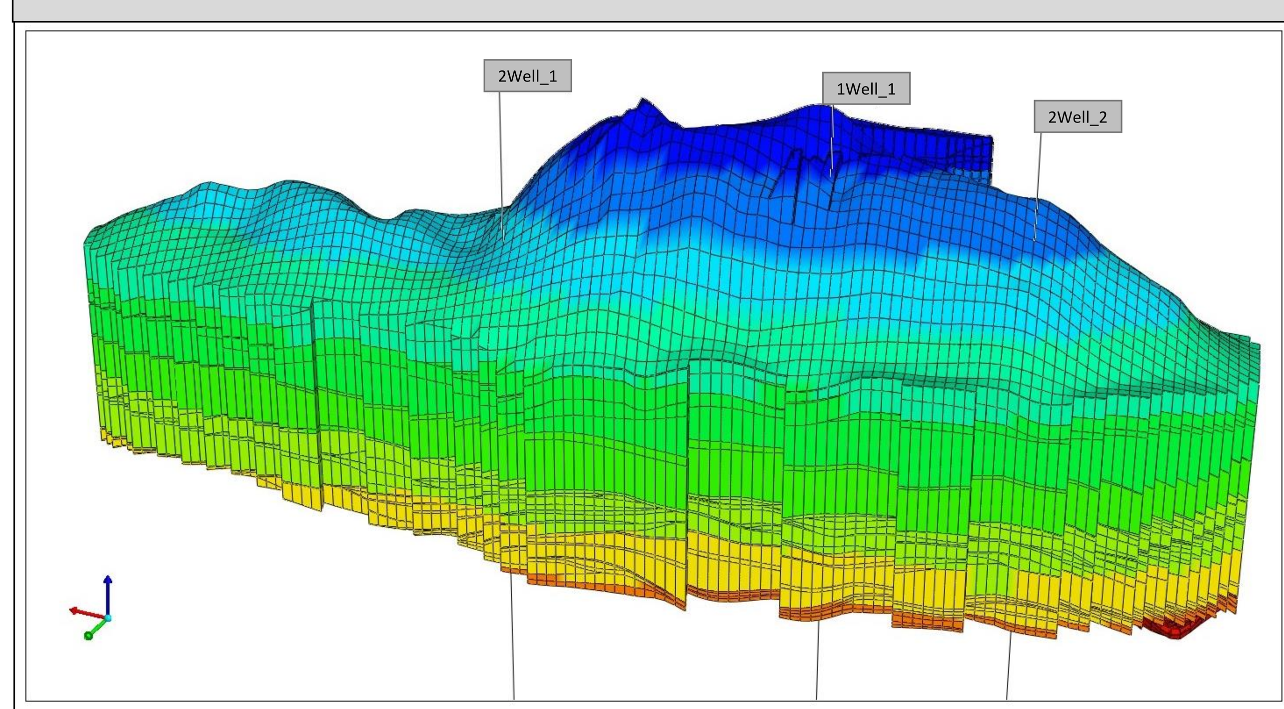
Thus, studying the effects of $CO_2$ injection in the subsurface and assessing the risks before proceeding with a storage project becomes paramount.

## METHODS

The present study utilizes a reservoir model of a depleted oil field in the Cambay basin in India for the simulation of $CO_2$ injection in a porous media. We developed the reservoir model based on the inputs provided by the operator to perform $CO_2$ injection and study the hydromechanical impact due to increased pore pressure in the subsurface. The model represents the major pay zone of the reservoir from Cambay basin.

We conducted petrophysical analysis and built 1D geomechanical models using the well logs available for the field. We studied the 3D geomechanical response of $CO_2$ injection combined with a fault-slip assessment to identify the risk of induced seismicity in $CO_2$ storage in the depleted oil field.

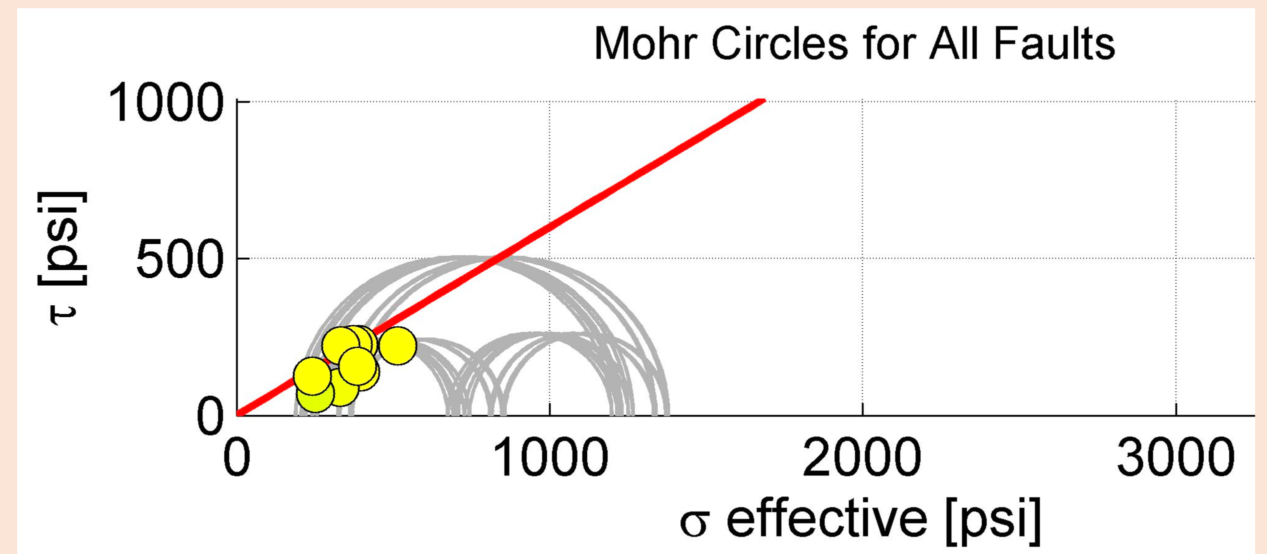
## RESERVOIR MODEL



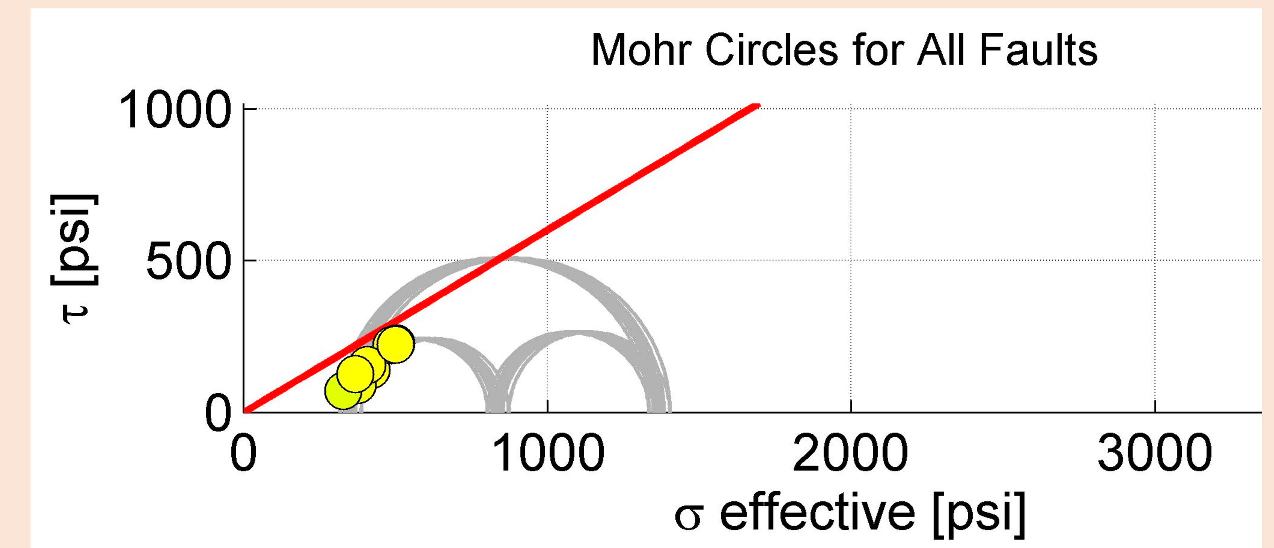

- The geometry, well positions, depth and grid system of the 3D conceptual reservoir model of the selected oil field.
- Coupled fluid-flow simulation conducted for $CO_2$ injection in a depleted oil field for 50 years (2005-2055) in single well and dual well injection scenarios.

## RESULTS

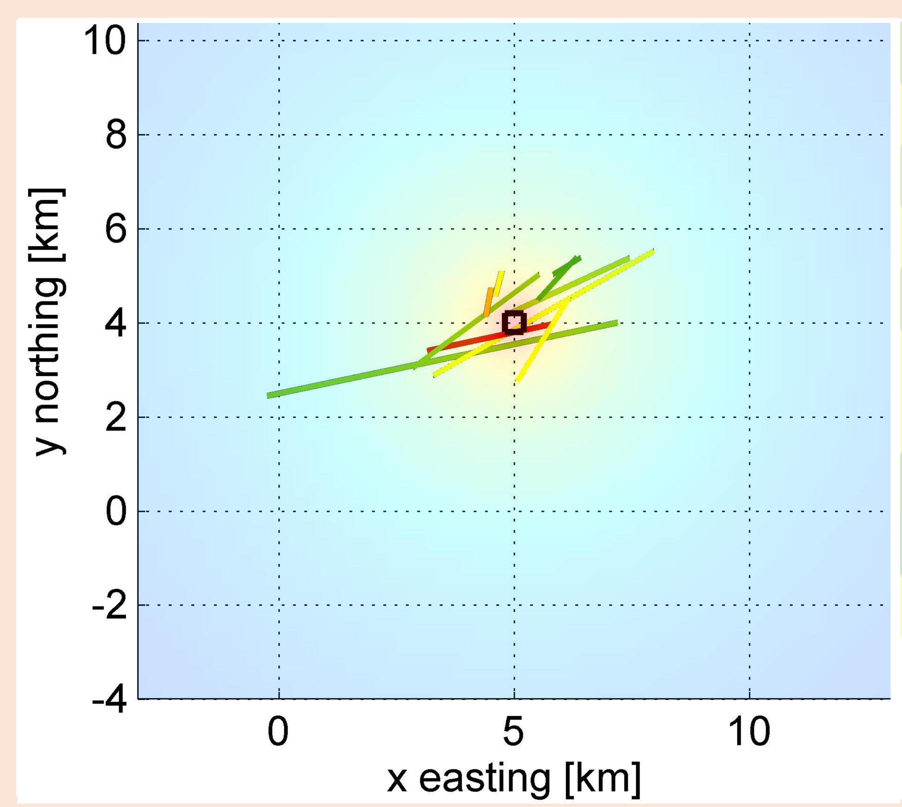
### Single well injection



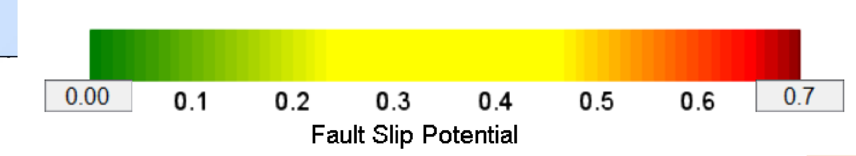

### Dual well injection

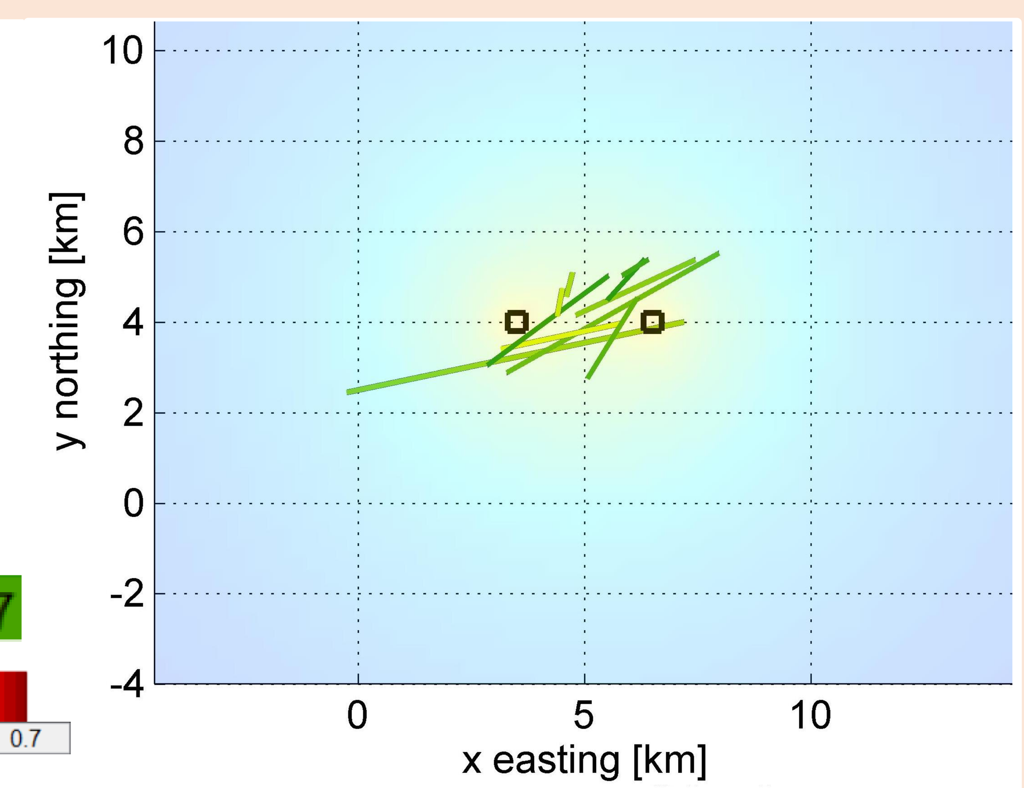



**(Deterministic)** Risk of fault slip in different injection scenarios represented through **Mohr diagrams**.
Two faults slip in single well injection while no fault slips in dual well injection, even though some faults are close to failure.




| Single well | Dual well |
|---|---|
| Fault #1, 0.13 FSP | Fault #1, 0.15 |
| Fault #2, 0.43 FSP | Fault #2, 0.09 |
| Fault #3, 0.16 FSP | Fault #3, 0.13 |
| Fault #4, 0.66 FSP | Fault #4, 0.21 |
| Fault #5, 0.13 FSP | Fault #5, 0.03 |
| Fault #6, 0.52 FSP | Fault #6, 0.19 |
| Fault #7, 0.46 FSP | Fault #7, 0.16 |
| Fault #8, 0.06 FSP | Fault #8, 0.02 |
| Fault #9, 0.05 FSP | Fault #9, 0.05 |
| Fault #10, 0.36 FSP | Fault #10, 0.07 |



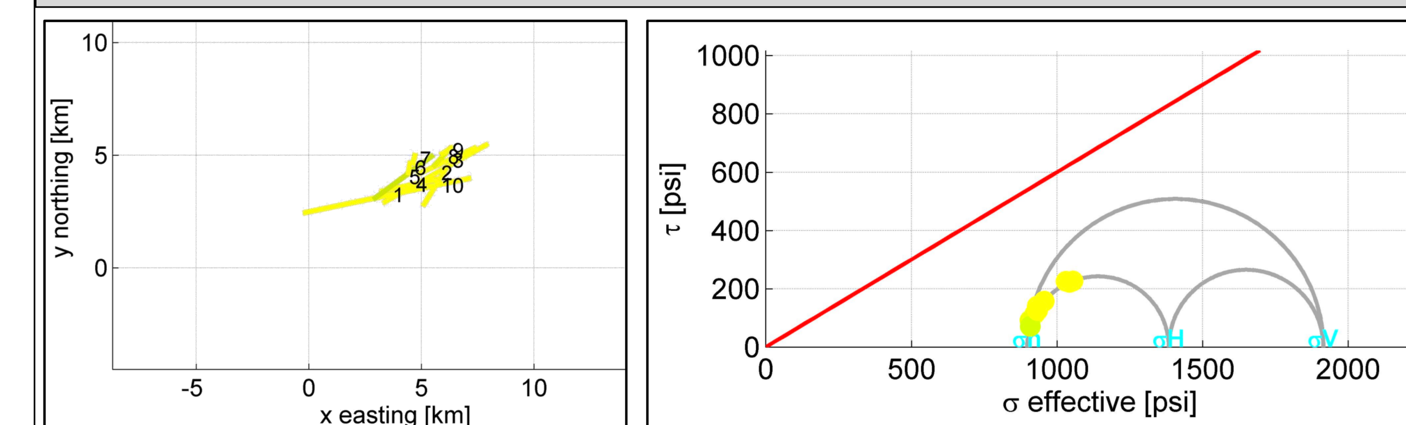

**(Probabilistic)** Fault slip potential (FSP) in different injection scenarios.
The highest FSP value is 0.66 (Fault#4) followed by 0.52 (Fault#6) and 0.46(Fault#7) during single well injection.
The corresponding FSP values are reduced to less than one-third in dual well injection, where the highest FSP value is 0.21.

- Proximity of faults to injection site and the orientation of faults with respect to the maximum horizontal stress are the primary factors in determining the fault slip potential.
- Length of the fault correlates negatively with the FSP.
- **Single-well injection** leads to localization of stress buildup leading to **high FSP** (average: **0.3**).
- **Dual well injection**, even with same amount of $CO_2$ injected, leads to much **lower FSP** (average: **0.11**).

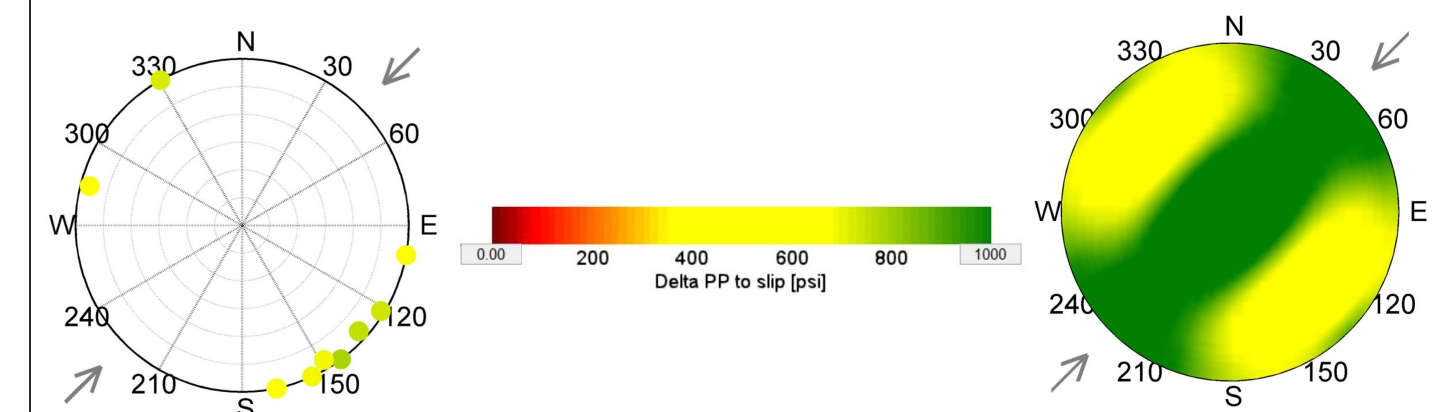
## Fault Slip Potential analysis

- We use the Fault Slip Potential (FSP) program (Walsh et al., 2017), to run a fault slip simulation using hydrologic and geomechanical parameters acquired from well logs as well as 3D seismic-based fault information.
- FSP employs both deterministic and probabilistic (stochastic) techniques.
- The deterministic technique uses the Mohr-Coulomb failure criterion to estimate the risk of fault slip.
- The probabilistic technique performs a Monte Carlo simulation on the model parameters, allowing for uncertainty using the tornado plot as input.

## Initial Stress State

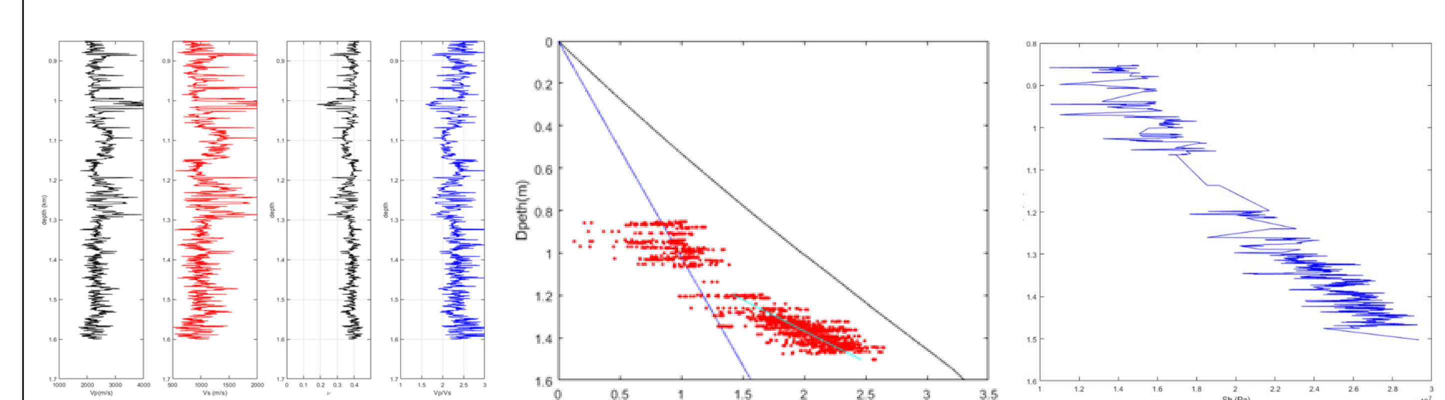



The location and initial stress state of the faults in the reservoir condition. The colour represents the pore pressure required for the fault to slip in Mohr-Coulomb failure




The orientation of the faults as shown in the stereonet diagrams. The arrows represent the direction of maximum horizontal stress.

## Geomechanical model



1D geomechanical model of the reservoir developed through the well log data including Poisson's ratio, pore pressure, and horizontal stress.

## CONCLUSION

A multi-well injection strategy reduces the probability of fault slipping considerably. Thus, they can be quite effective in cases where the reservoirs are highly fractured or where the faults are closer to their critically stressed state.

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