

## Introduction

Understanding multiphase fluid flow in porous media is critical for subsurface energy applications as well as hydrocarbon production and recovery. Shale caprocks are essential for limiting fluid leakage and preserving long-term containment. In this work, laboratory core-flooding experiments using a CO<sub>2</sub>-water-CO<sub>2</sub> injection sequence were conducted to determine relative permeabilities, and numerical models were used to investigate the impact of heterogeneity on multiphase flow in shales.

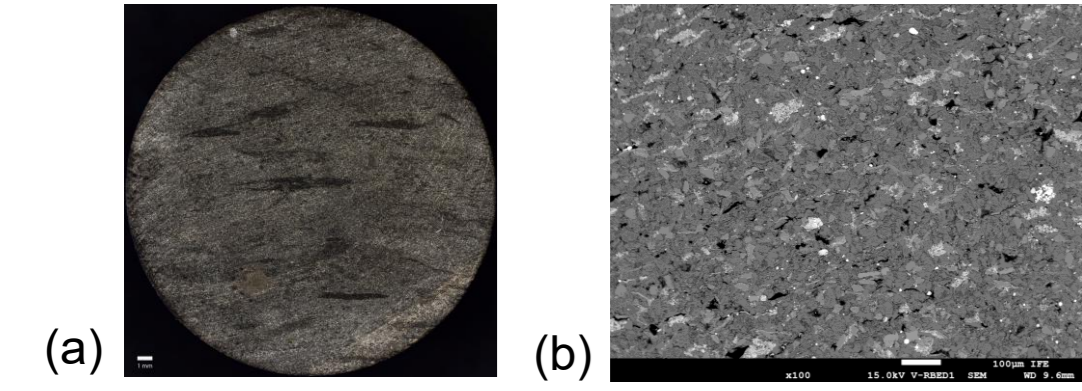


Figure 1. Shale sample a) high-resolution picture b) SEM

## Methods

- Sample preparation:** Shale core plug assembled with end pistons and placed inside a core-flooding cell under controlled confining pressure.
- CO<sub>2</sub> injection 1:** CO<sub>2</sub> injected into the dry sample to measure baseline CO<sub>2</sub> flow response and apparent permeability.
- Water injection:** Water injected to evaluate water flow response and permeability.
- CO<sub>2</sub> injection 2:** CO<sub>2</sub> reinjected after water flooding to monitor breakthrough, water displacement, and changes relative to the initial CO<sub>2</sub> baseline.
- Monitoring:** Inlet/outlet pressure, differential pressure, were recorded throughout the experiment.

### Experimental injection sequence:

dry sample → CO<sub>2</sub> injection → water injection → CO<sub>2</sub> reinjection

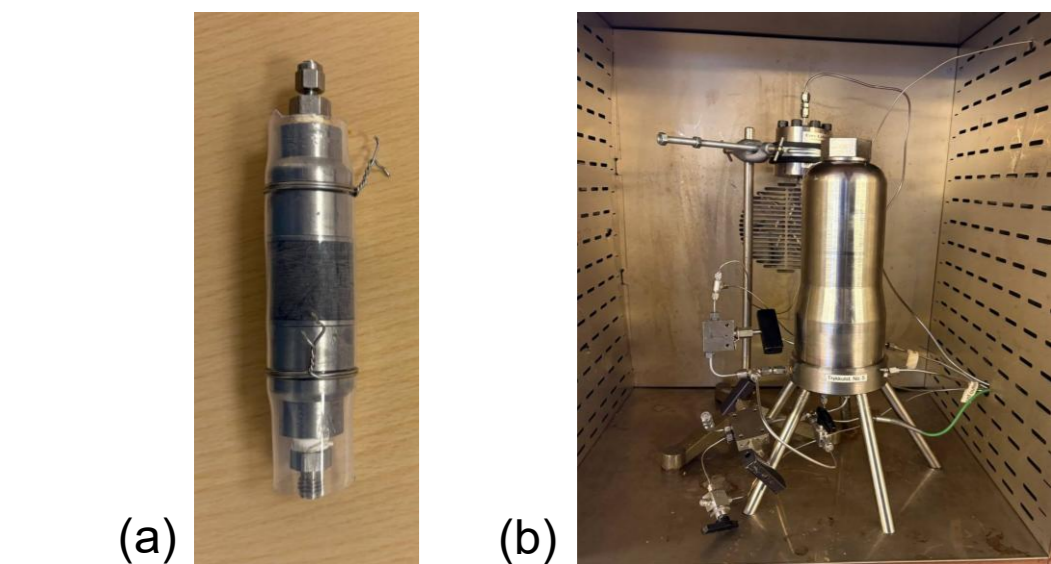


Figure 2. a) shale core plug assembly b) the experimental core-flooding cell.

## Numerical models

- Incompressible, immiscible flow
- Capillary forces are negligible
- Permeability is heterogeneous

### Mathematical model

Saturation constraint, porosity, relative permeabilities:

$$S_w + S_o = 1 \quad \frac{\partial \phi}{\partial t} = 0$$

$$k_{rw} = S_w^2, \quad k_{ro} = (1 - S_w)^2$$

Saturation equation:

$$\phi \frac{\partial S_w}{\partial t} + \frac{\partial}{\partial x_j} \left( -\kappa \frac{k_{rw}}{\eta_w} \frac{\partial P_f}{\partial x_j} \right) = 0$$

Pressure equation:

$$\frac{\partial}{\partial x_j} \left( -\kappa \sum_{\alpha=w,o} \frac{k_{r\alpha}}{\eta_\alpha} \frac{\partial P_f}{\partial x_j} \right) = 0$$

### Numerical method

- Newly developed Julia code
- Water saturation is solved using a conservative first-order explicit upwind method
- The pressure equation is treated implicitly using a pseudo-transient iterative approach
- Algorithm is GPU ready



## Buckley-Leverett benchmark

To validate the accuracy of the numerical model, we simulate 1D two-phase flow in a homogeneous porous medium and compare the results against the analytical Buckley-Leverett solution. The numerical solutions closely match the analytical shock front location and pressure profile.

To assess the effect of coupling, we tested four configurations:

- Analytical pressure + explicit saturation update
- Pseudo-transient pressure + explicit saturation update
- Analytical pressure + implicit saturation update
- Pseudo-transient pressure + implicit saturation update

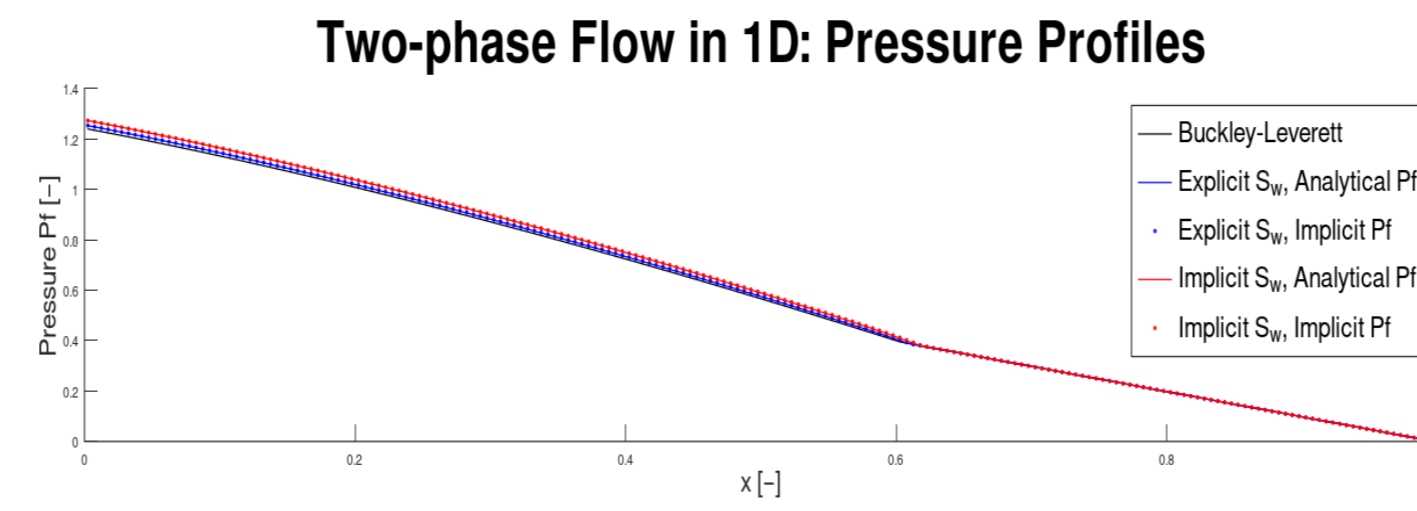
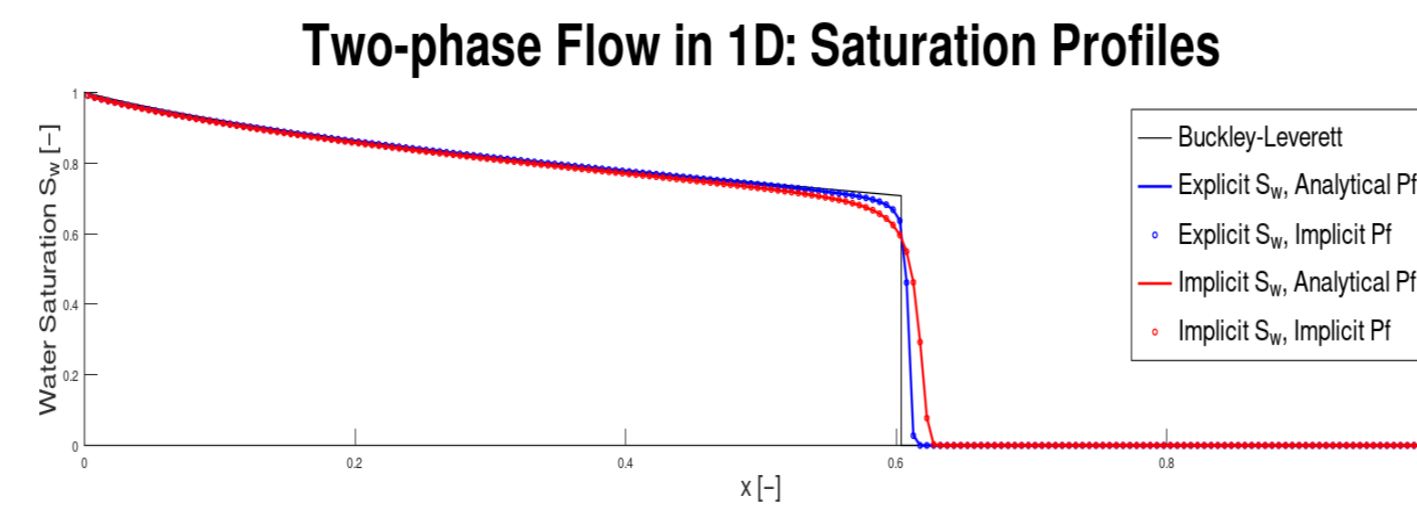


Figure 3. Buckley-Leverett benchmark for 1D

## Results

- CO<sub>2</sub>-water-CO<sub>2</sub> injection sequence was performed.
- During the first CO<sub>2</sub> injection into the dry shale sample, inlet and outlet pressures were monitored to establish the baseline CO<sub>2</sub> flow response.

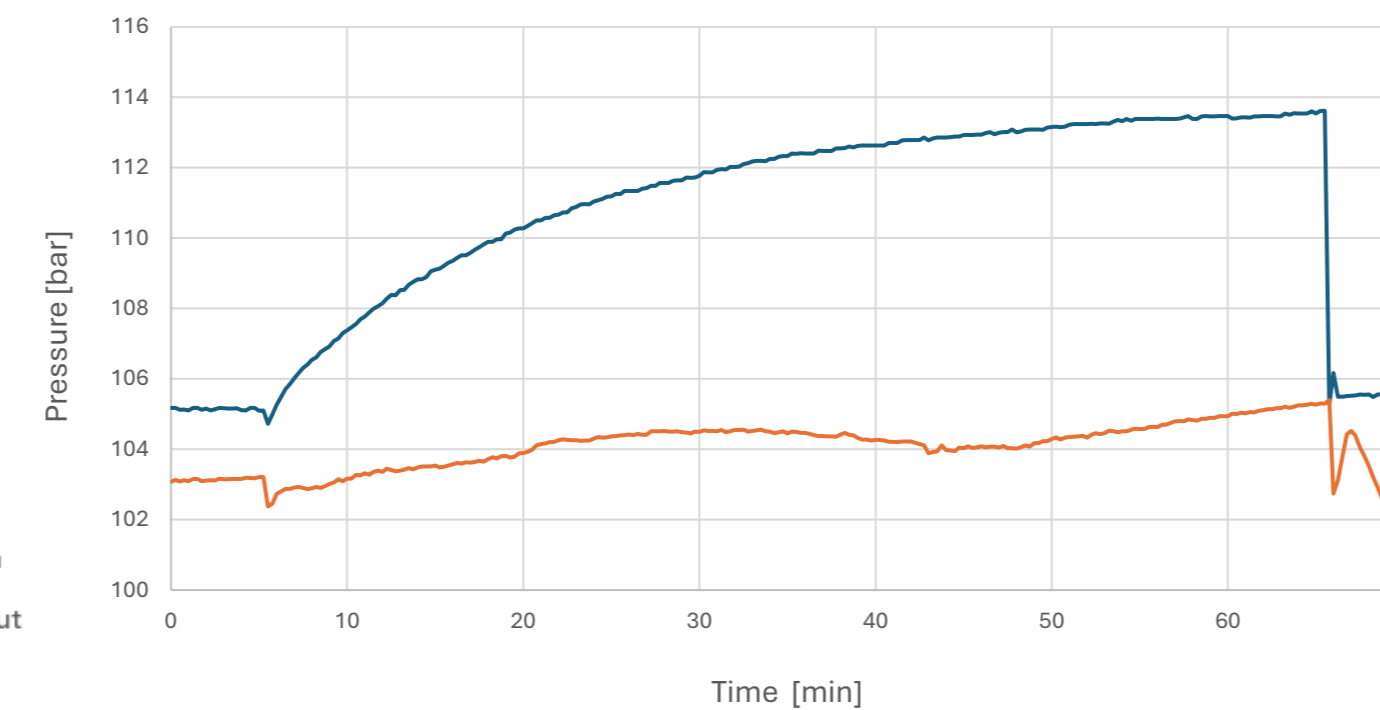


Figure 4. Pressure response during CO<sub>2</sub> injection into dry shale

- Apparent permeabilities were calculated from the measured pressure difference, flow rate, and sample geometry.
- The results highlight the importance of saturation history and multiphase flow effects on shale caprock permeability.

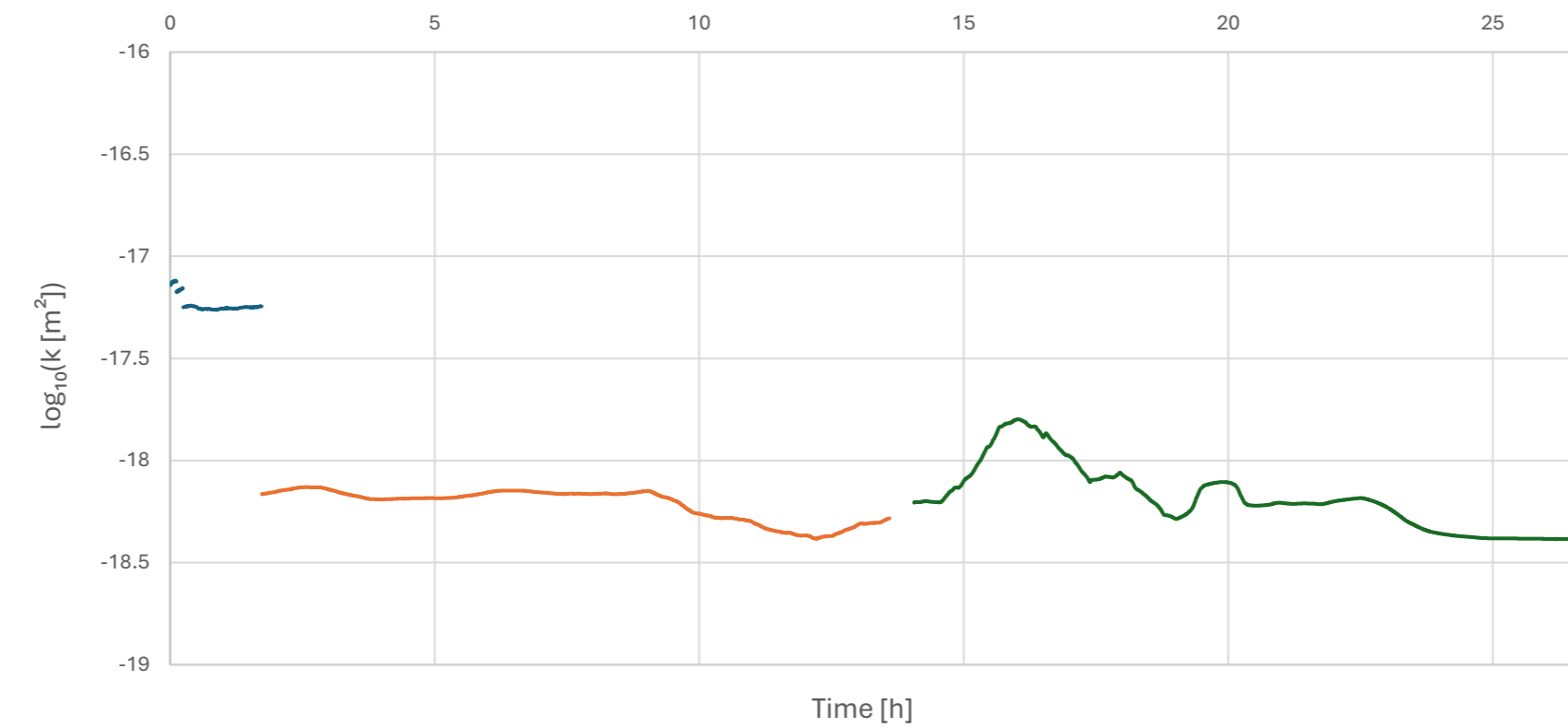


Figure 5. Permeability evolution during CO<sub>2</sub>-water-CO<sub>2</sub> injection.

In the numerical simulations, four heterogeneous permeability geometries were evaluated under different flow directions, resulting in eight simulation cases.

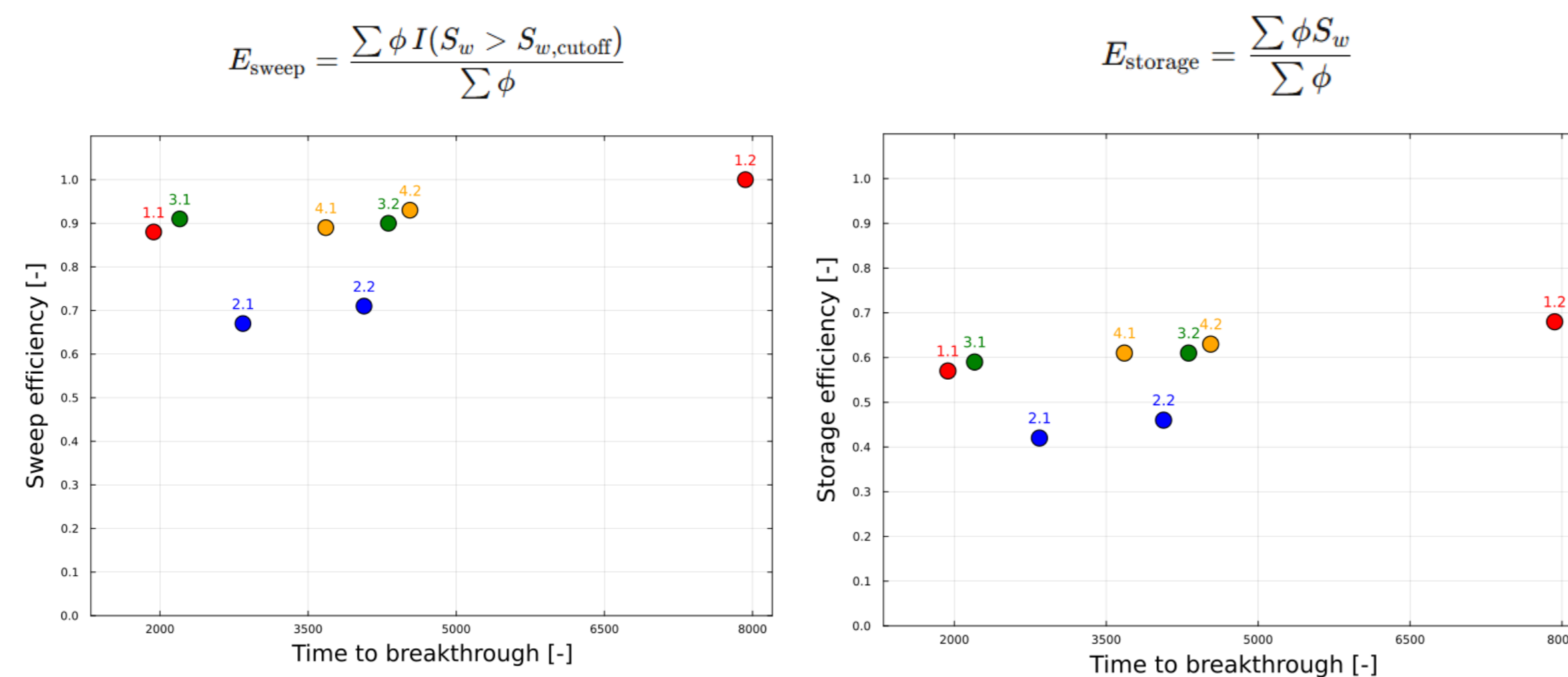
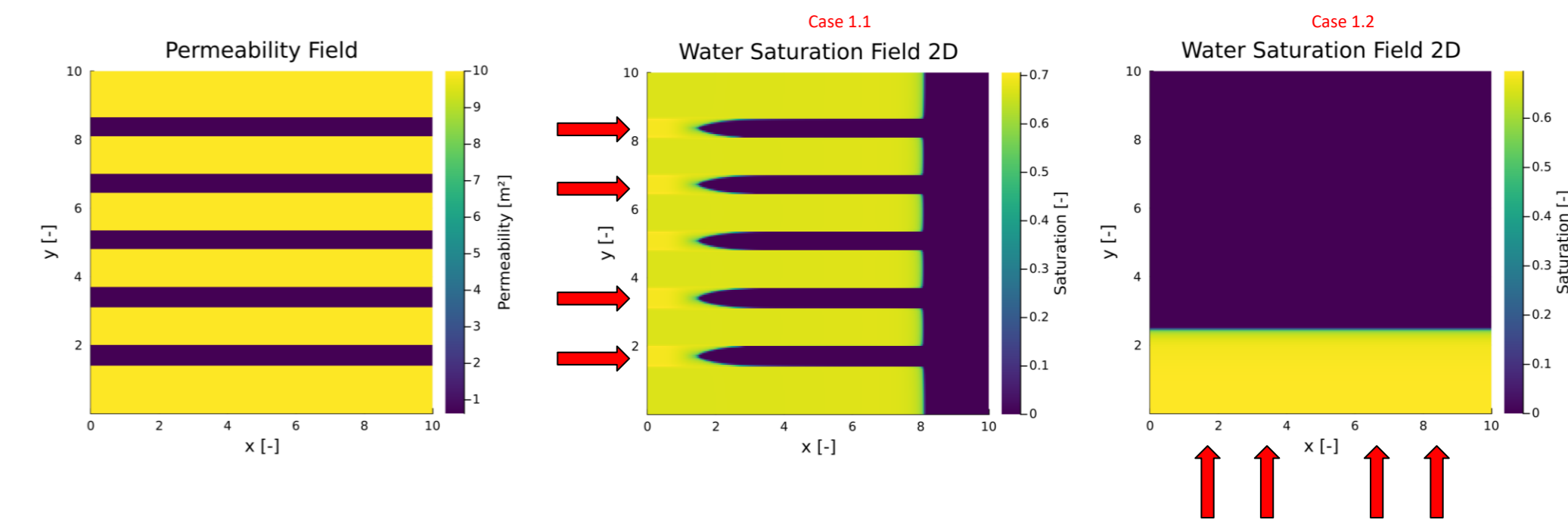


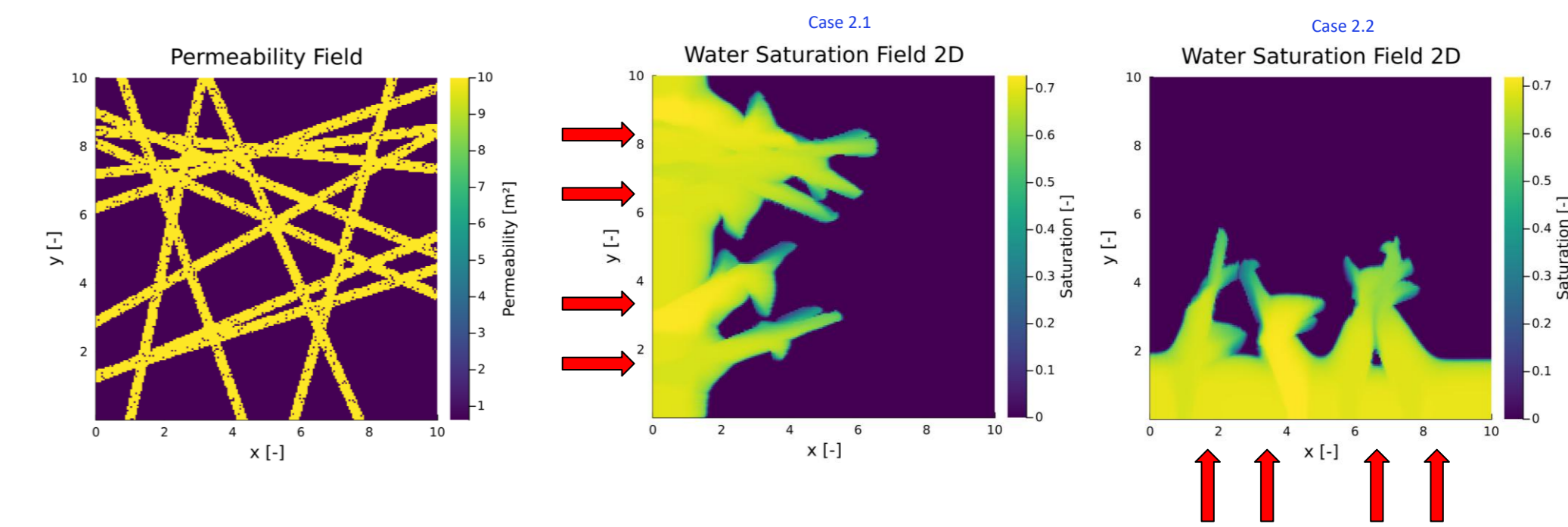
Figure 6. Sweep and storage efficiencies at first breakthrough

## Numerical results

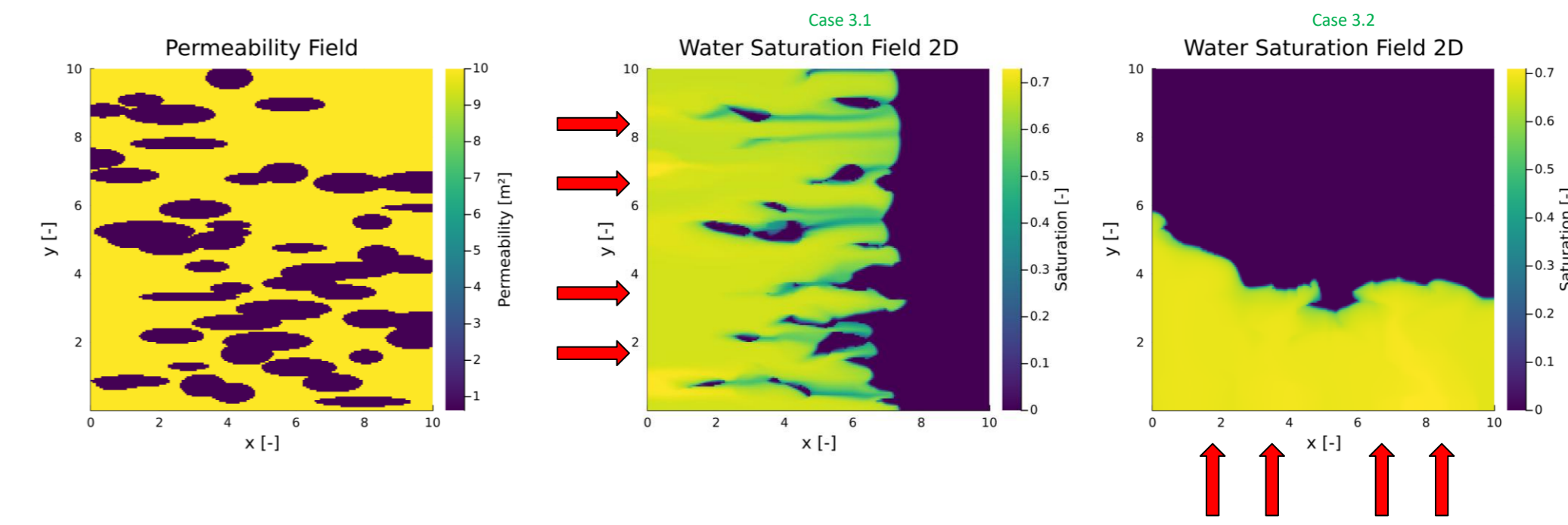
### Case 1: Layered porous medium



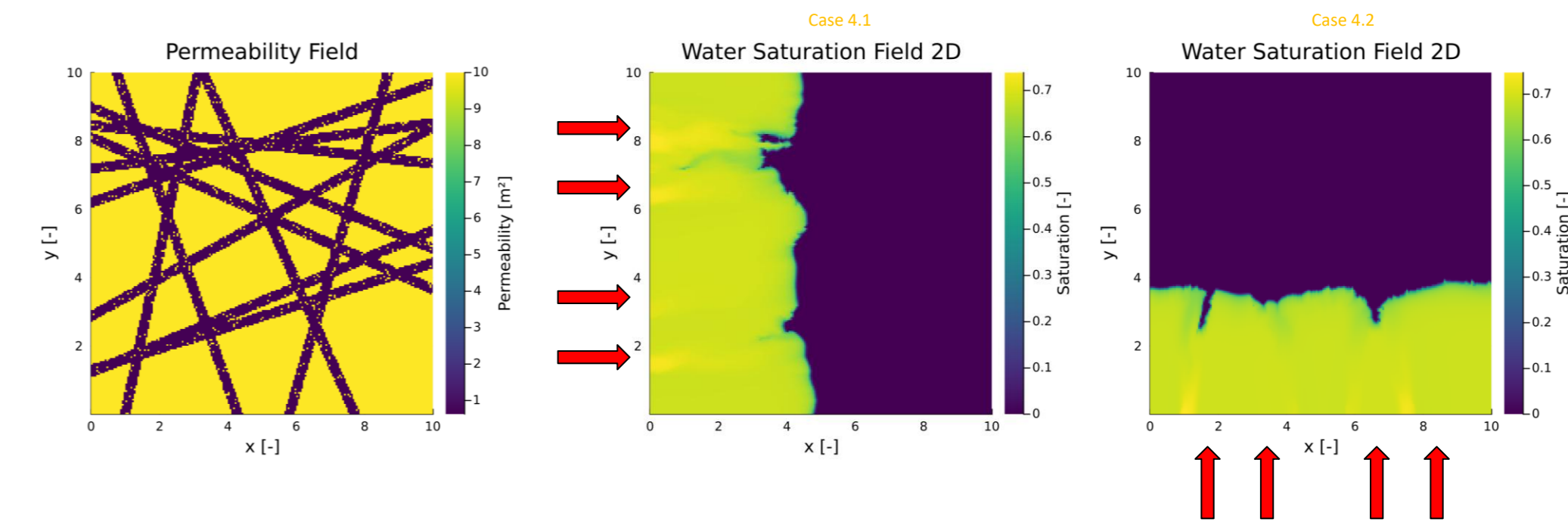
### Case 2: Fractured porous medium



### Case 3: Lenses-type porous medium



### Case 4: Porous medium with sealing fractures



## Conclusions

- CO<sub>2</sub>-water-CO<sub>2</sub> experiments were used to investigate pressure response and apparent permeability in shale caprocks.
- After CO<sub>2</sub> reinjection, the apparent permeability remained low, close to the water-saturated state, indicating that water invasion continued to restrict CO<sub>2</sub> flow pathways.
- The numerical results show that heterogeneity strongly influences multiphase flow behaviour in shales. Different geometrical distributions of porosity and permeability lead to changes in preferential flow pathways, saturation distribution, and sweep efficiency. These results highlight the importance of accurately representing geological heterogeneity when assessing flow processes in shales.

## Future work

- Continue CO<sub>2</sub>-water-CO<sub>2</sub> injection experiments under controlled confining pressure to improve reproducibility and data quality, and identify conditions under which a breakthrough (sudden decrease in apparent CO<sub>2</sub>-permeability) may take place.
- Extend the models to represent more realistic shale heterogeneity and improve predictions of multiphase flow and caprock integrity during CO<sub>2</sub> storage.
- Coupling experiments and simulations will improve understanding of shale behavior during CO<sub>2</sub> injection and support caprock integrity assessment.

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