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CO_2 Storage in Gulf Coast Saline Aquifers
and
Pilot Case Study of Wellbore Leakage Mitigation for CO_2 Storage Projects

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CO_2 Storage in Gulf Coast Saline Aquifers

Project Overview

Contributors:

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ExxonMobil: Gary Teletzke, Ganesh Dasari, Ben Jennette, Steve Davis, Rodrick Myers, Joe Patterson, Martin Lacasse, Nathan Way, Mike Braun, Robert Wenger, Eric Druppel, et al.

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Geology

Estimation of Storage Efficiency at Different Scales and Environment of Deposition

Simulation

Modeling and Simulation of Dynamic Storage Capacity

Geomechanics

Laboratory Measurements of Geomechanical Properties of the Formation

Geomechanics

Numerical Estimation of the Sealing Capacity of the Formation

Key Questions – Set A

How to model and predict CO_2 plume propagation?

1. What is the relationship between architecture, stratigraphy, and fluid migration pathways?

2. What is the best practice for incorporating the key stratigraphic features in compositional simulation models?

3. What are the costs and benefits of high-resolution models?

4. What is the controlling force: gravity or pressure?

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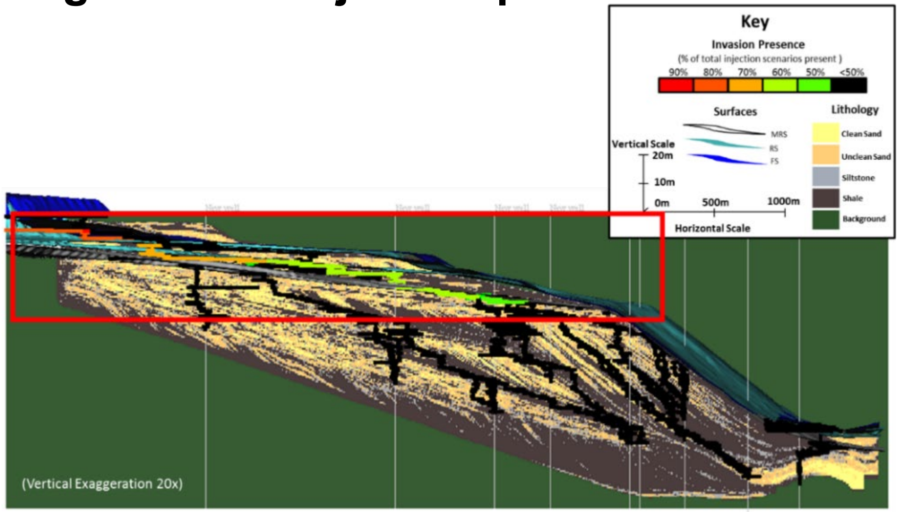
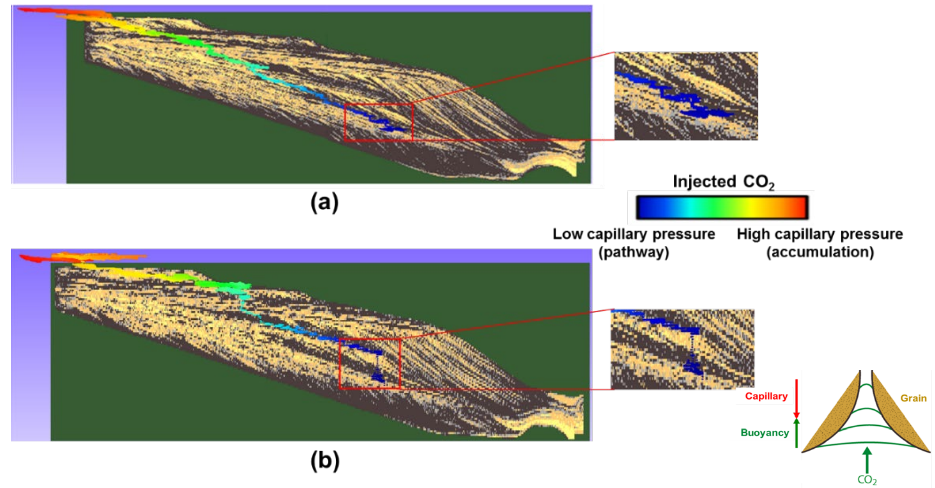
Identification of key architectural surfaces using different injection points

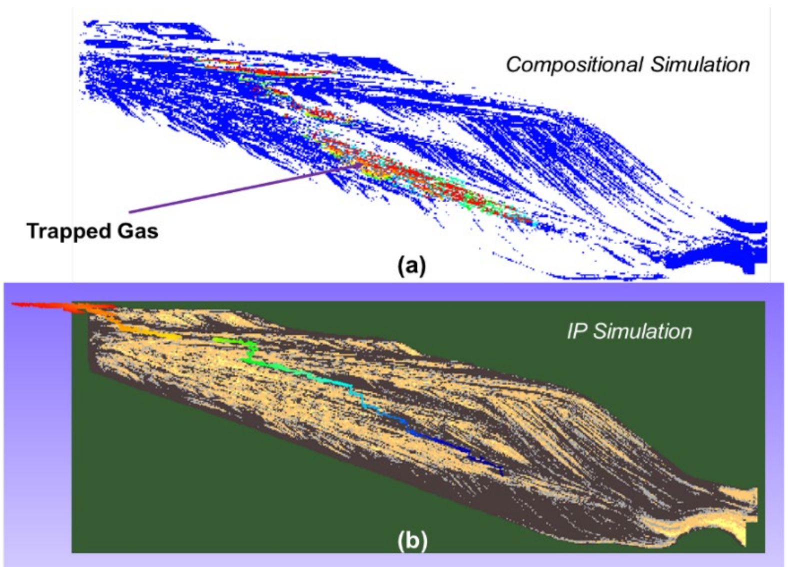


Upscaling – Maintain key features



Invasion percolation vs. Reservoir simulation

Property	Invasion Percolation	Compositional Reservoir Simulation
Time-dependence, dynamics	✗	✓
Buoyancy driven flow	✓	✓
Pressure gradient	✗	✓
Capillarity	✓	✓
CO_2 solubility	✗	✓
Comprehensive physics (consideration of all trapping mechanisms)	✗	✓
Higher resolution geological model with faster simulation run time	✓	✗



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Key Questions – Set B

How much CO_2 can we store?

1. What are the storage mechanisms?
2. What is the fate of CO_2 over the years?
3. What are the geomechanical effects of storage?
4. What is the maximum sustainable injection pressure?
5. What are the worst case scenarios?

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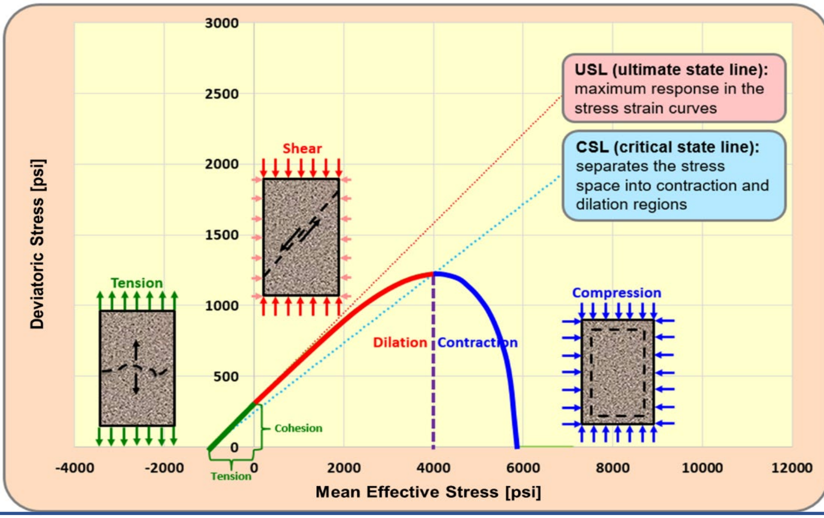
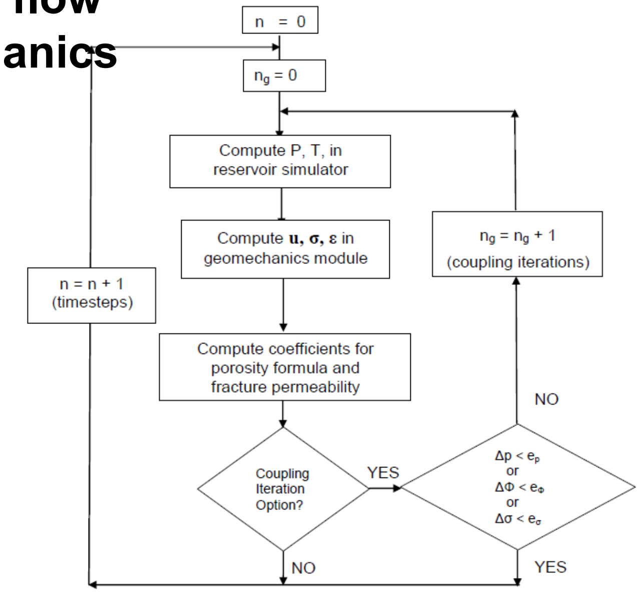
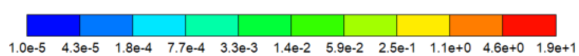
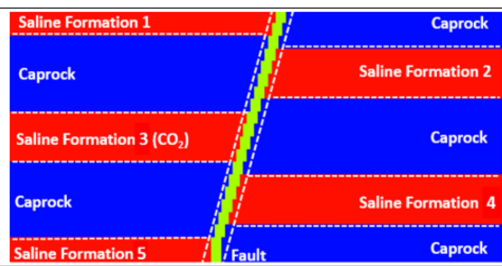
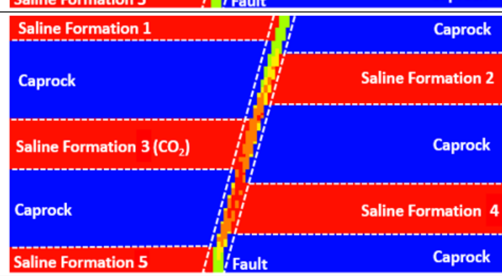
Capture strain softening/hardening and post yield behavior

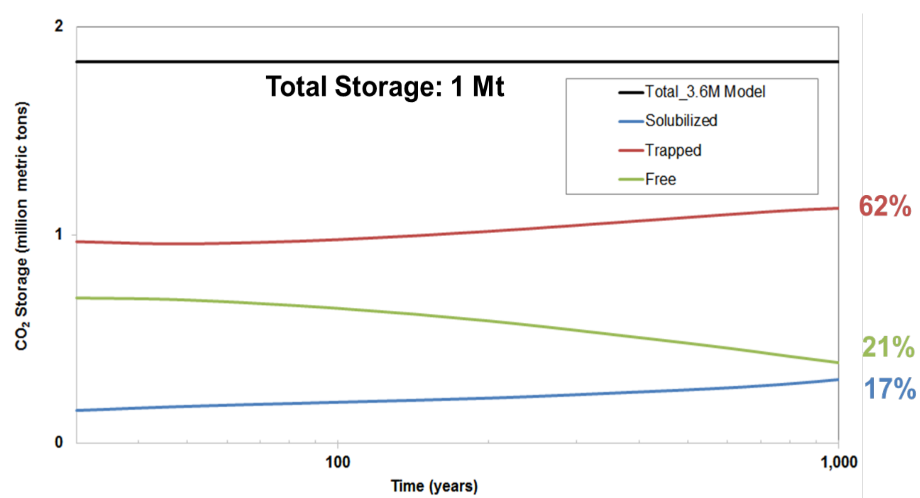


Coupled fluid flow and geomechanics simulation



Permeability – log scale [mD]	
Initial state: Permeability along the fault is homogeneous at the given value of 0.1 mD.	
End of 5 years: Large permeability increase occurs along the storage formation, particularly near the bottom of the storage formation due to its proximity to the injector.	

Storage mechanisms per Mt injected



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Pilot Case Study of Wellbore Leakage Mitigation for CO_2 Storage Projects

Contributors:

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ETHZ: James Patterson

Project funded by CCP

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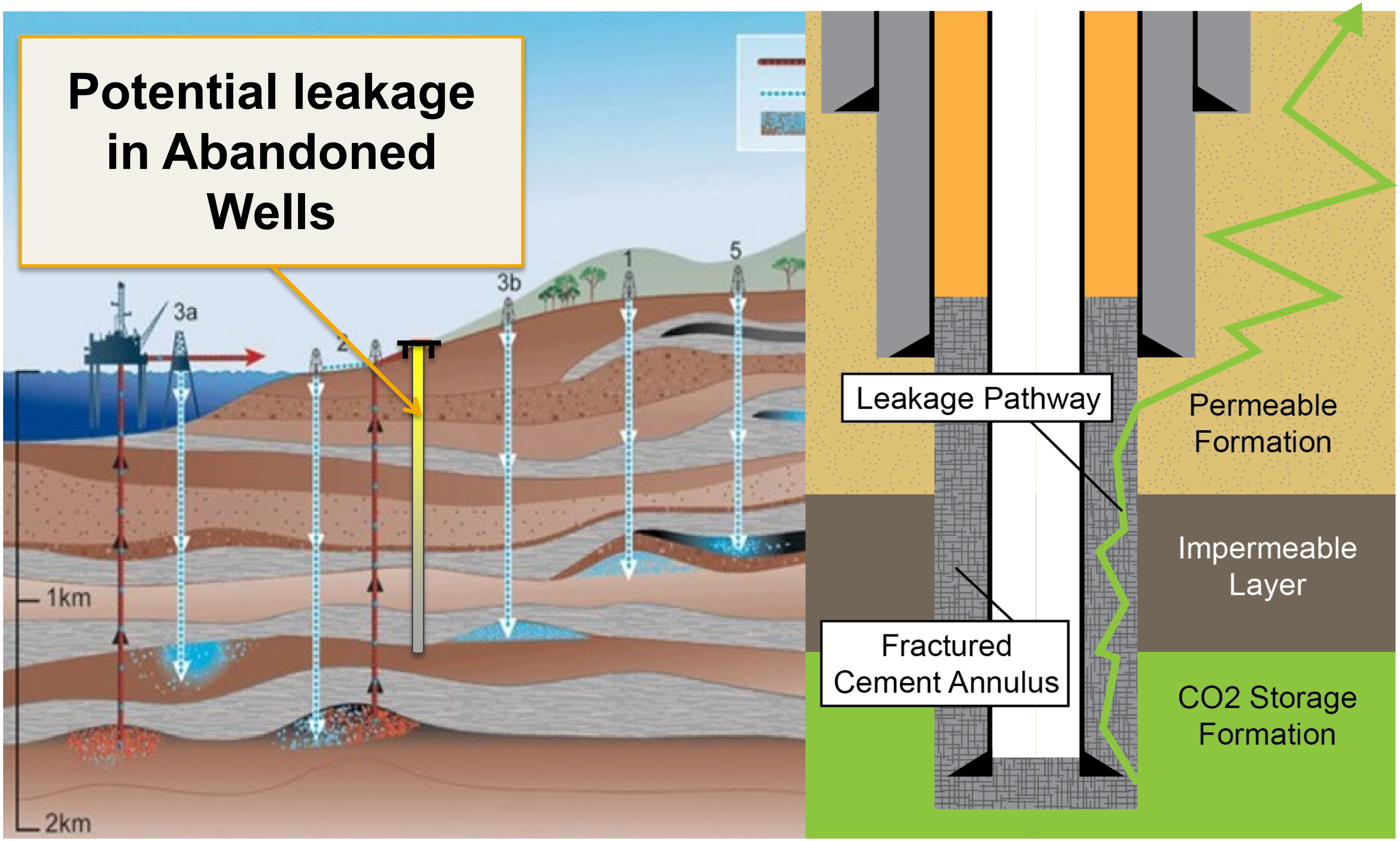
Leakage in Wellbore Cement



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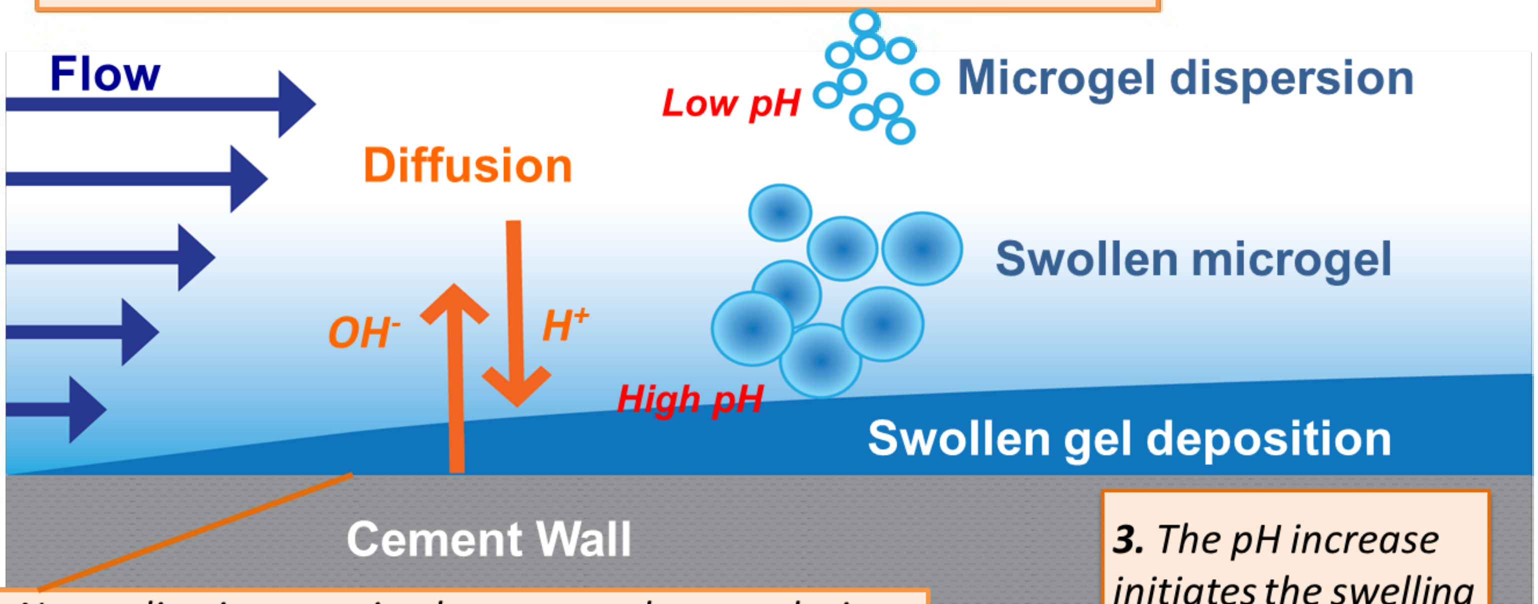
pH Triggered Gelling Mechanism

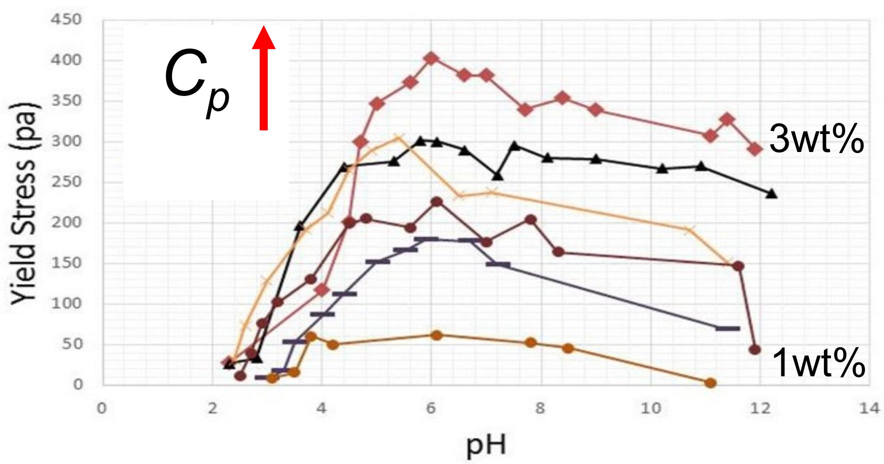
1. The reactive polymer solution enters the cement fracture flushing the alkaline brine that was originally in the fracture.



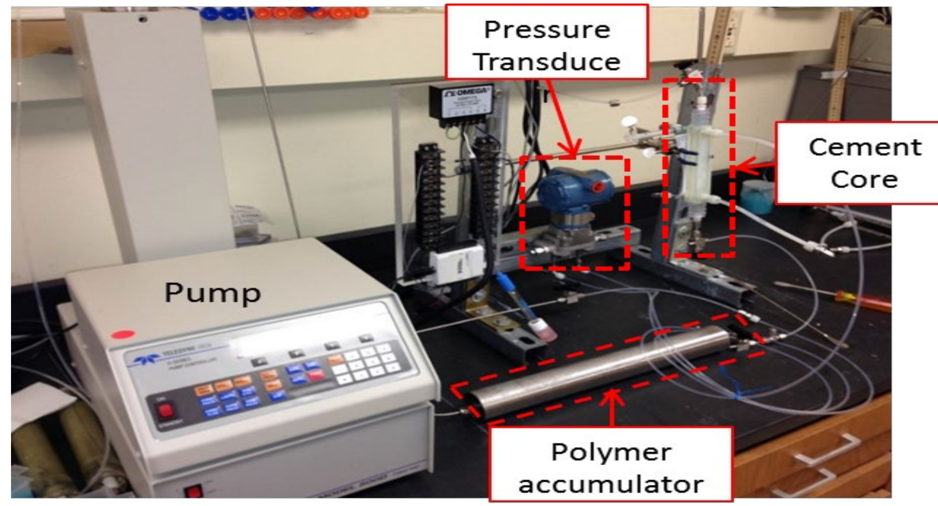
2. Neutralization reaction between polymer solution and cement surface causing the pH to increase.

3. The pH increase initiates the swelling of microgel resulting in the viscosification of the gel

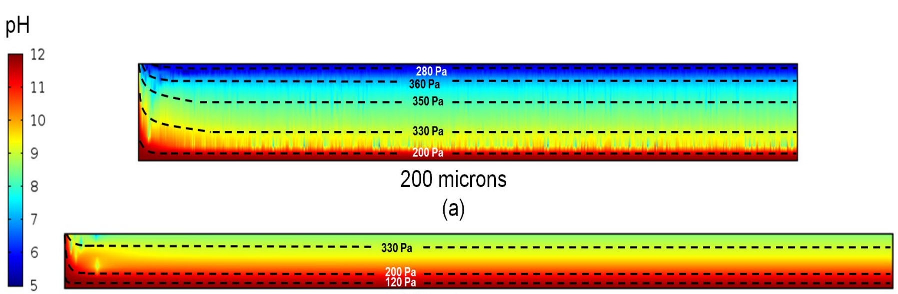
Rheology measurements



Cement corefloods



CFD modeling



200 microns
(a)

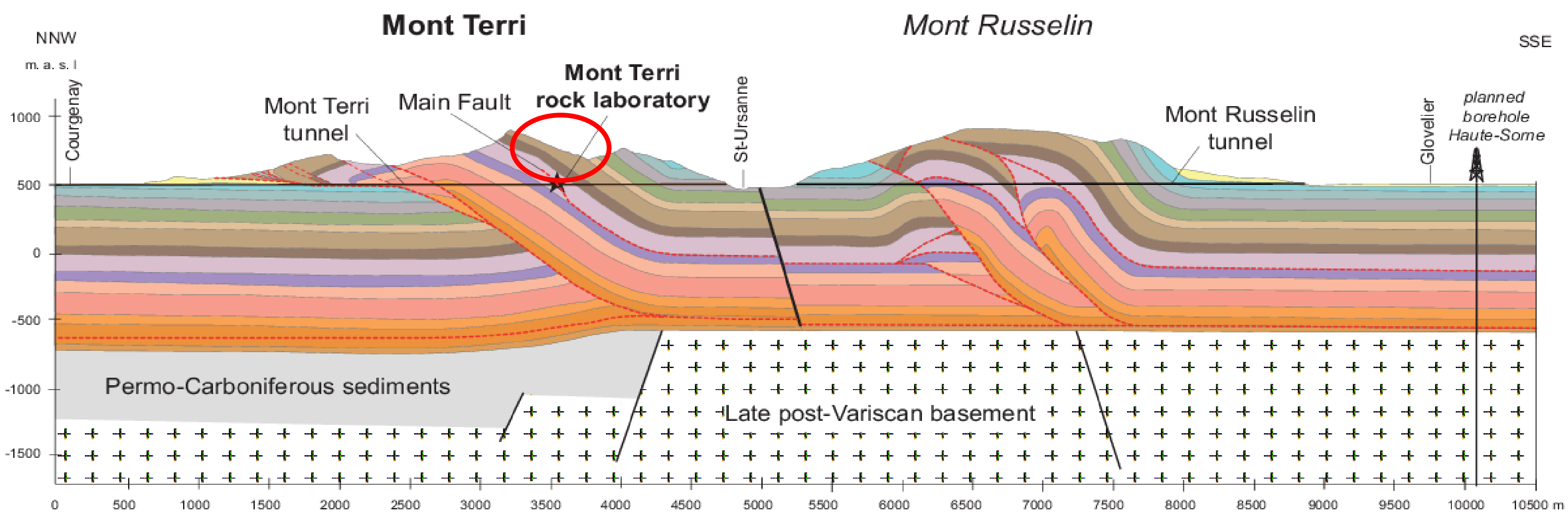
100 microns
(b)

Experimental procedure

No	*Stage*	*Chemicals*	*Details*	*Value*	*Duration*
1	Chelating agent preflush (pretreatment)	Sodium Triphosphate ($Na_5P_3O_{10}$)	12 wt% or saturated solution (water solubility = 14.5 g/100 mL)	454-549 g/gal.	1-3 FV* (3 FV recommended)
2	Soaking (pretreatment)	—	—	—	24 hr
3	Polymer flood	Carbopol® 934	Aqueous solution 1-3 wt%	114 g/gal. (3 wt% soln.)	Until steady-state reached
4	Shut in (gelation)	—	—	—	24 hr

Pilot Test of Polymer Gelant

- **Objective: to mitigate CO_2 leakage along wellbores used for injection of CO_2 below the minimum stress of the caprock** (Opalinus Clay).
- **Opalinus Clay:**
  - Incompetent, silty, sandy shales, acts as a geological barrier
  - Can be used for underground deposition of fluids and a long-term containment of CO_2.



Mont Terri anticline, Switzerland

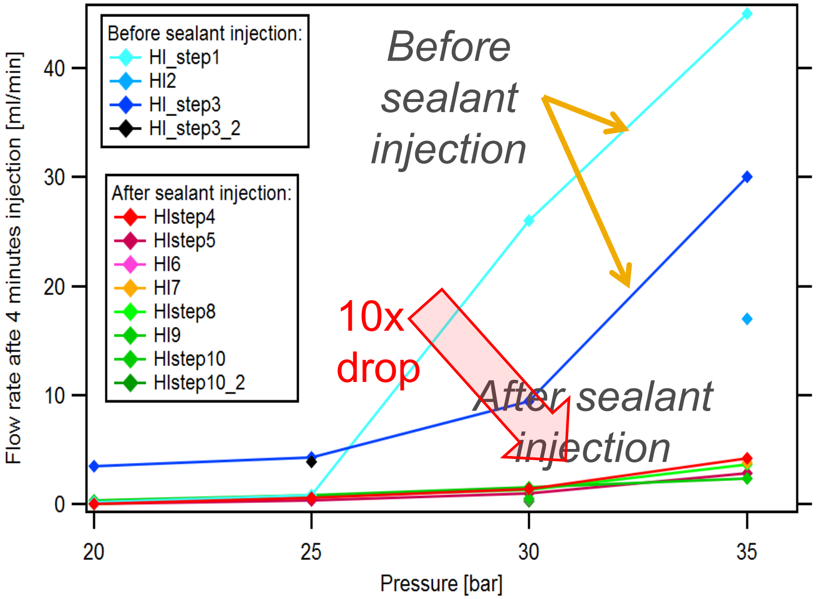
The Chronological Order of the Chemical Injection

- Chelating agent was injected into test interval (#5) for pretreatment
- Interval 5 was soaked with the chelating agent for 24 hr
- Polymer solution was mixed for 24 hr during injection and soaking time of pretreatment
- Polymer was injected into interval 5
- The first performance test with Pearson water (synthetic formation brine) was done 18 hr after polymer injection
- The second performance test with Pearson water was done 24 hr after the first performance test
- Additional short- and long-term performance tests with CO_2 were conducted subsequently.

Results – Performance Test

- The flow rates during constant head injection (HI) tests were measured after 4 min for each pressure step.
- The injection tests HI were performed before the sealant injection and showed high flow rates up to 45 ml/min at 35 bar.
- The injection tests after the sealant injections yielded much lower flow rates with a maximum of 4.2 ml/min at 35 bar.
- The long-term injection tests also show low flow rates (0.11-3.8) ml/min at 30-35 bar.

Recorded flow rates vs. applied pressures



Thank You!

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