

# Geological Storage of CO<sub>2</sub>: Sensitivity and Risk Analysis

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April 10, 2014



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## Section 1

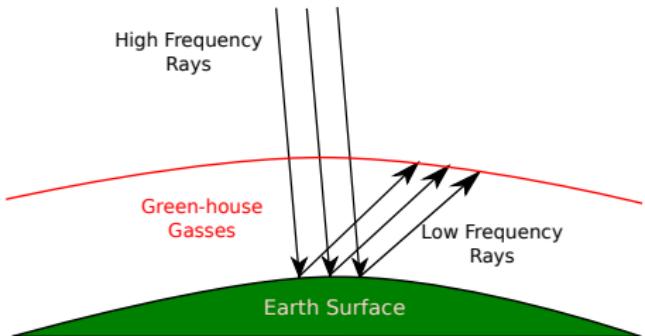
### Introduction

# Underlying Goal



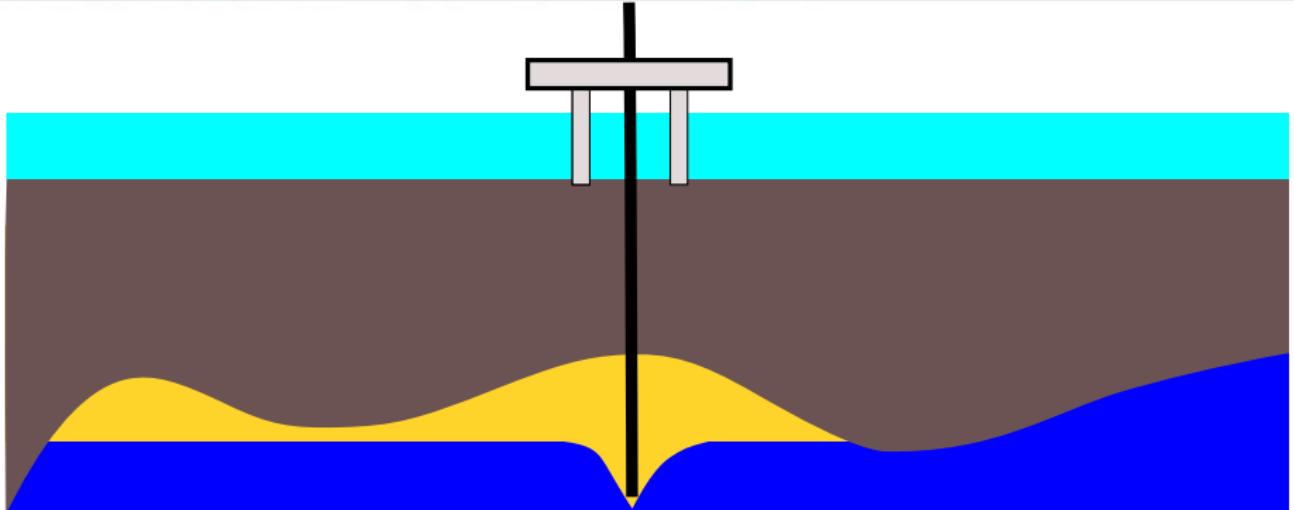
To study the impact of geological uncertainty on the success of CO<sub>2</sub> storage operation, and demonstrate the value of realistic geological modeling.

# Green-House Gas Effect



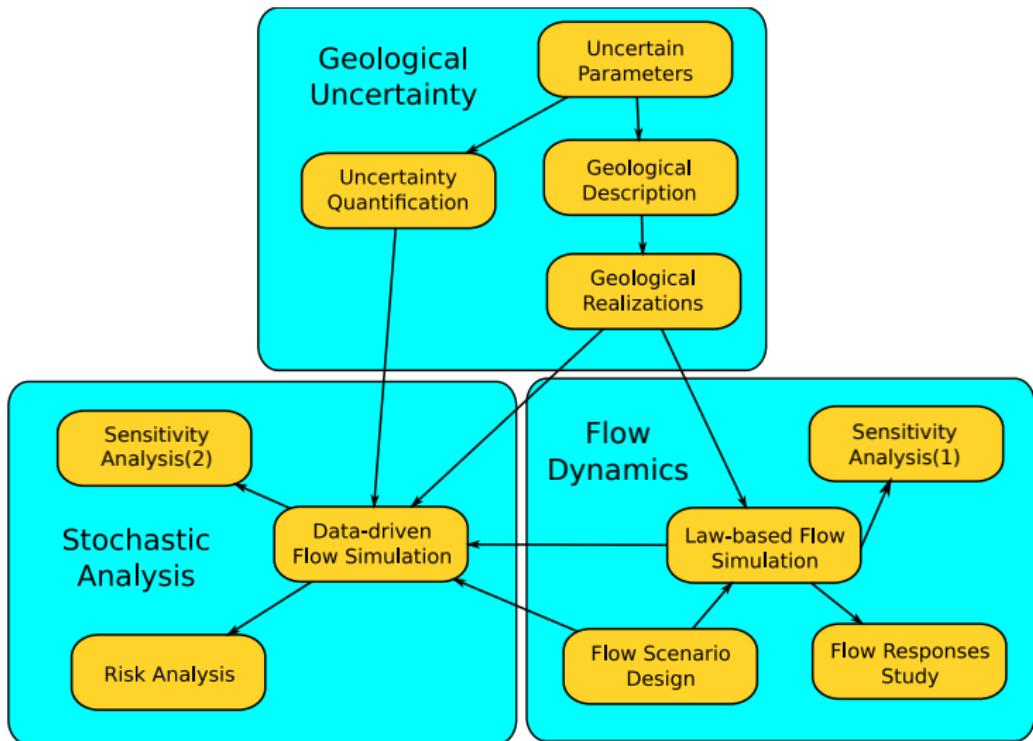
The theory of green-house effect relates the earth climatic change to the trapping of heat energy by the green-house gases, and mainly carbon dioxide.

# Geological CO<sub>2</sub> Storage



- Key technology to reduce the CO<sub>2</sub> emission into atmosphere
- Objectives for a successful storage:
  - To maximize the storage volume.
  - To maximize the injection rate.
  - To minimize the risk of leakage.

# Modeling Procedure





## Section 2

### Geological Modeling

# The SAIGUP



- SAIGUP stands for *sensitivity analysis of the impact of geological uncertainties on production forecasting in clastic hydrocarbon reservoirs*'.
- The interdisciplinary SAIGUP study was initiated to increase the understanding of the influence of geological uncertainties on the prediction of oil field recoveries.

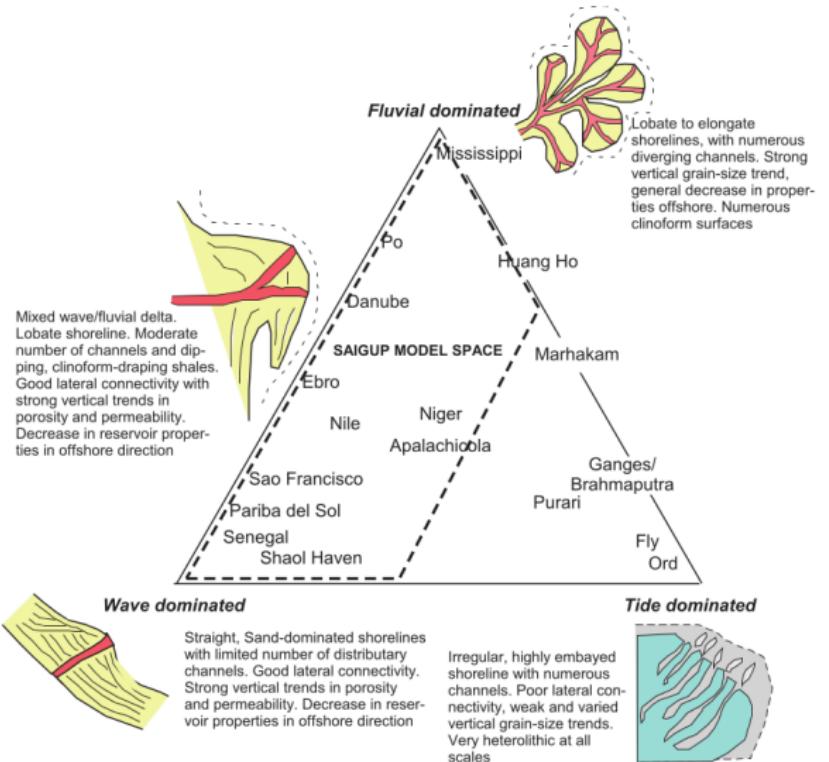
# Depositional Systems



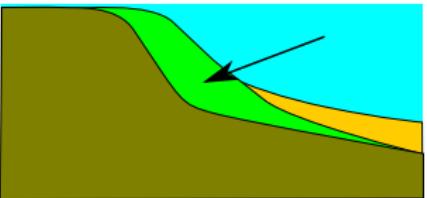
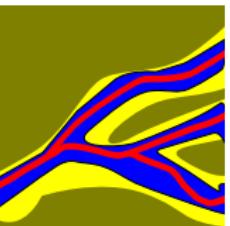
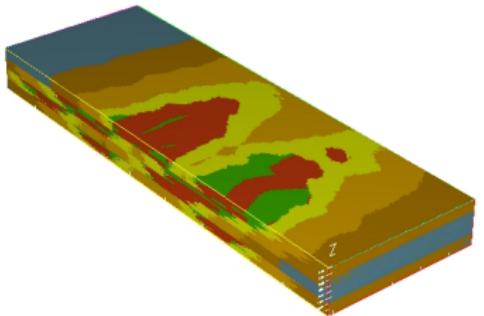
# Depositional Systems



Howell et al., Petroleum Geoscience, Vol. 14 2008, pp. 17–34

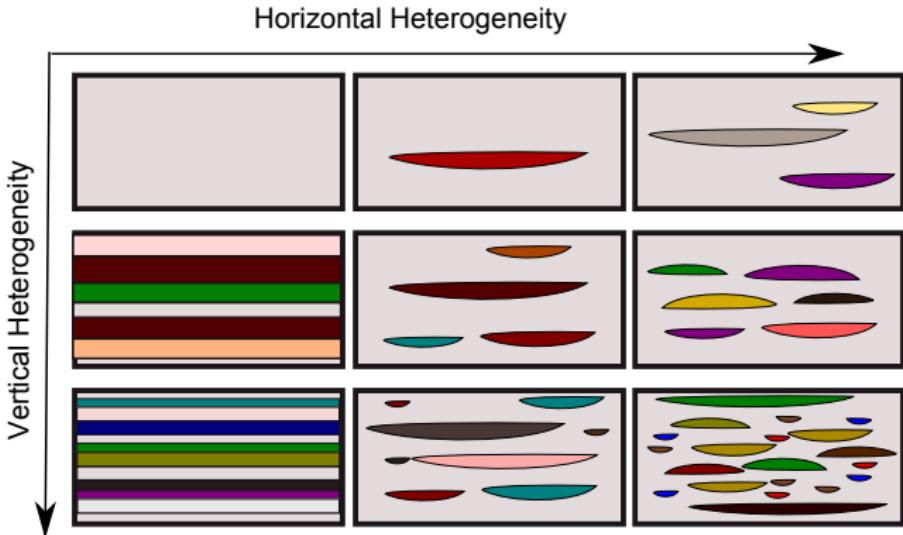


# Geological Realizations



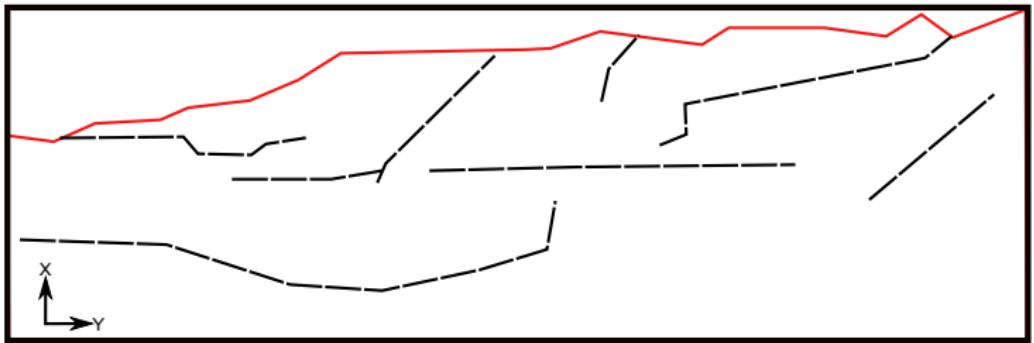
- Shallow-marine systems are considered.
- 160 realizations from the SAIGUP setup are used.
- Structural and sedimentological parameters are examined.

# Geological Depositional Description



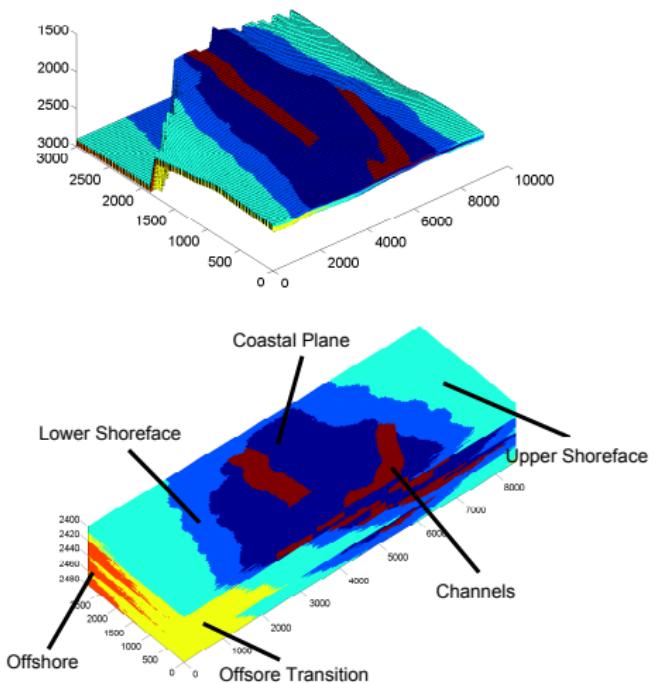
- Sedimentological variability is modeled in small and large scales.
- All models are considered in a progradational sedimentary environment.

# Geological Structural Description



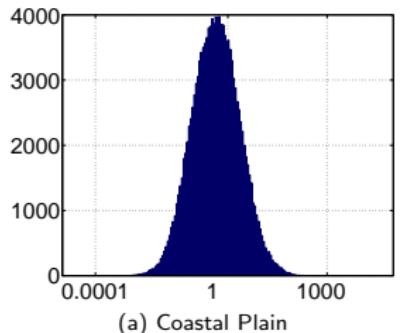
Structural aspects are modeled via fault modeling. Within the SAIGUP setup, faults are considered with different levels of **intensity**, **orientation**, and **transmissibility**. The orientations may vary in both lateral directions, and *we consider a grid that contains faults in both directions*.

# Facies Modeling

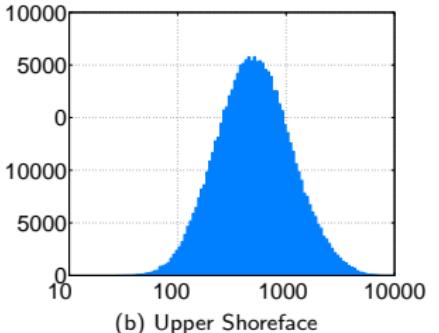


# Facies Modeling

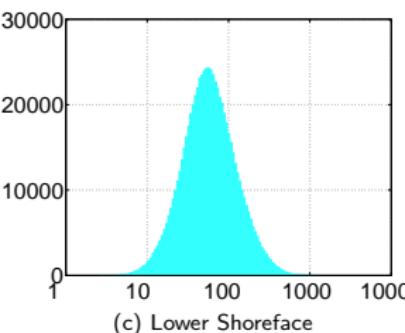
Lateral Transmissibility,  $\text{cP} \cdot \text{m}^3 / \text{day/bar}$



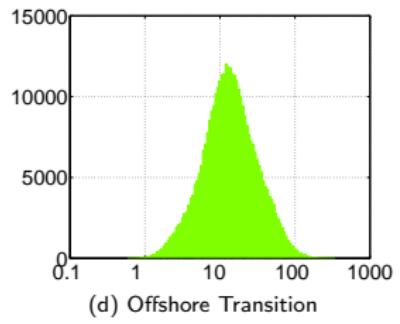
(a) Coastal Plain



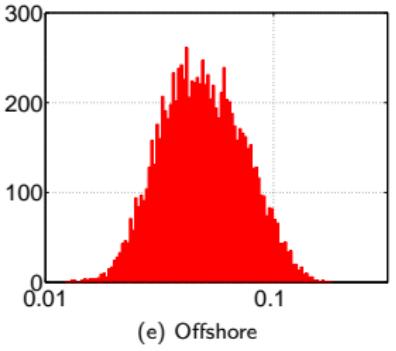
(b) Upper Shoreface



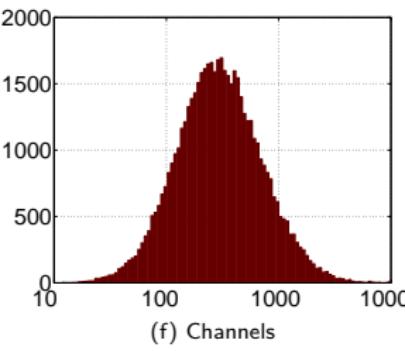
(c) Lower Shoreface



(d) Offshore Transition



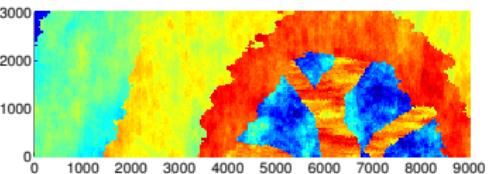
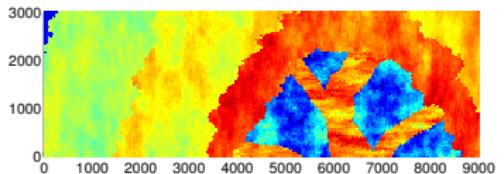
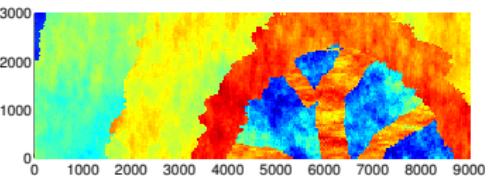
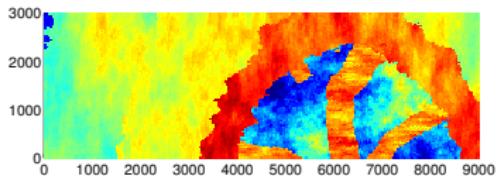
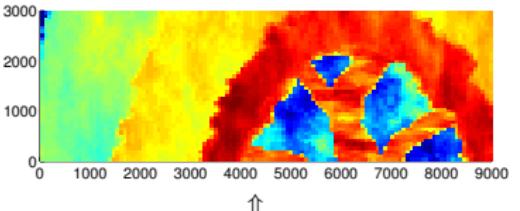
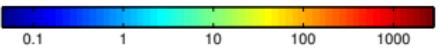
(e) Offshore



(f) Channels

# Upscaling

Logarithmic of Lateral Transmissibility,  $\text{cP} \cdot \text{m}^3 / \text{day/bar}$



# Geological Parameters



## Depositional:

- Lobosity
- Barriers
- Aggradation
- Progradation

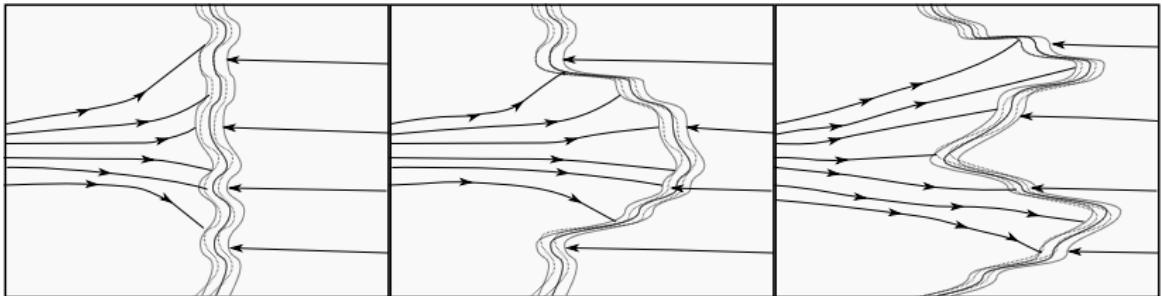
## Structural:

- Unfaulted
- Faulted

## Other:

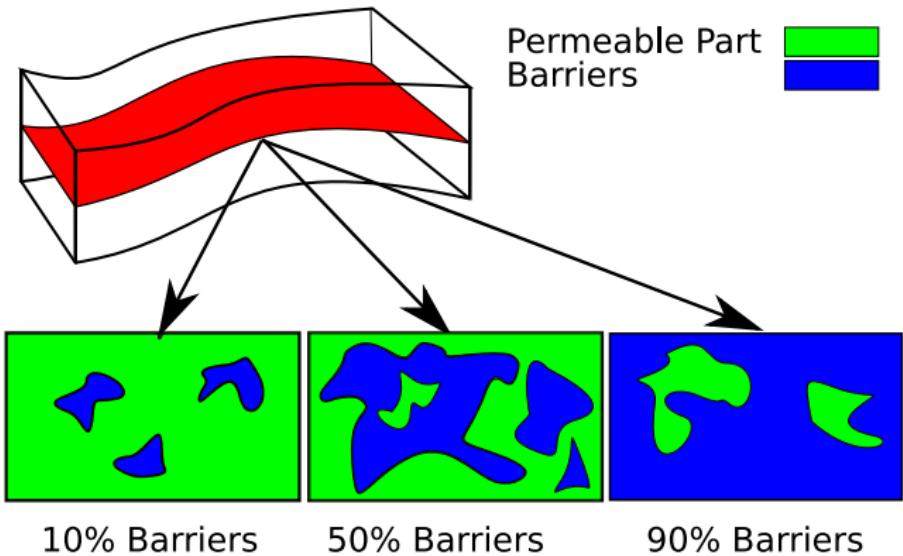
- External Aquifer

# Lobosity



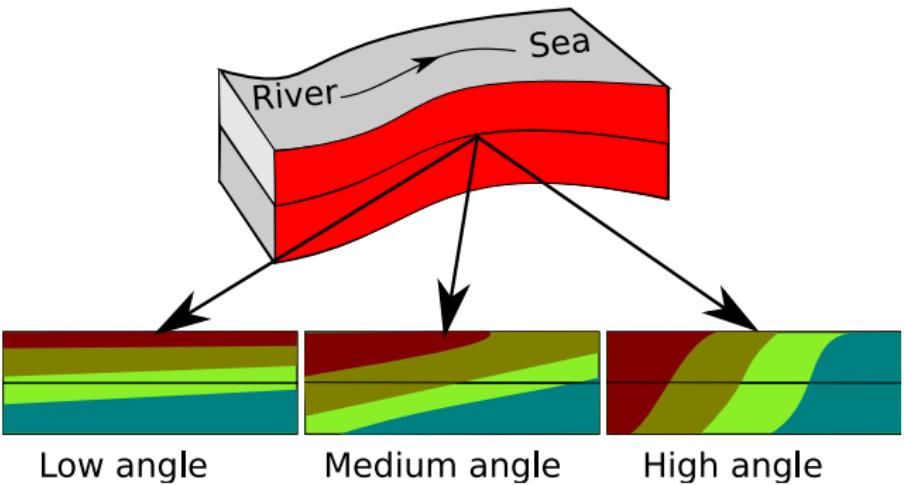
*Lobosity* levels are defined based on the shoreline shape, which is caused by the interplay between fluvial and wave forces.

# Barriers



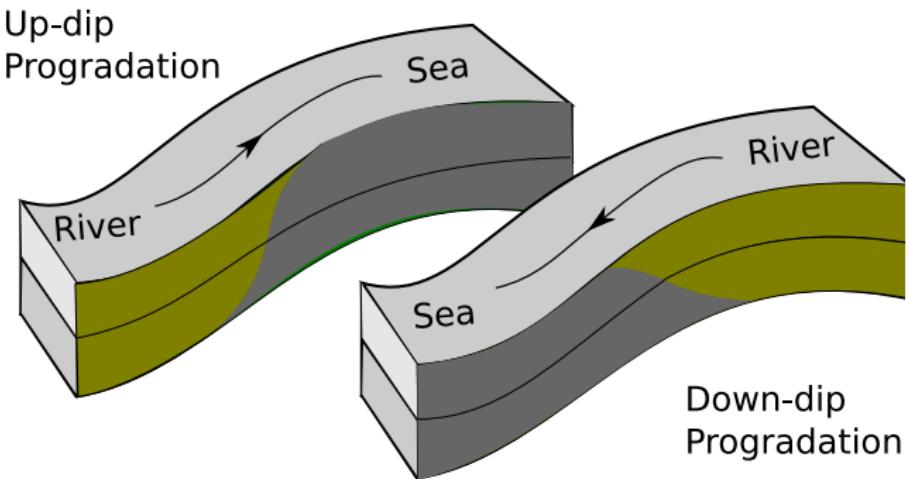
Periodic floods and fluctuations in fluvial system can result in shale draped surfaces. These surfaces act as *barriers* to flow in both vertical and horizontal directions.

# Aggradation



The change in the fluvial flux results in a shift in the depositional rock types from the river to the sea. We consider the angle between transitional deposits as the *aggradation angle*.

# Progradation



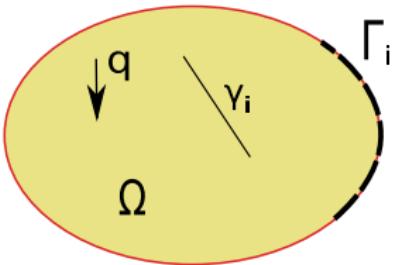
Tectonic activities in shallow marine systems can result in various orientations of river to sea depositions that is considered as *progradation* direction in the SAIGUP study.



## Section 3

### Flow Modeling

# Two-Phase Flow Equations



**Mass balance:** For phase  $\alpha = \{\text{Water, CO}_2\}$ , we have:

$$\frac{d}{dt} \int_{\Omega} \phi \rho_{\alpha} S_{\alpha} d\tau + \int_{\Gamma} \rho_{\alpha} v_{\alpha} \cdot n d\sigma = \int_{\Omega} q_{\alpha} d\tau \quad (1)$$

for phase saturation  $S_{\alpha}$ , phase flux  $v_{\alpha}$ , and the source/sink term for the phase mass rate  $q_{\alpha}$ .  $\rho_{\alpha}$  is the phase density.

# Two-Phase Flow Equations

**Darcy law:**

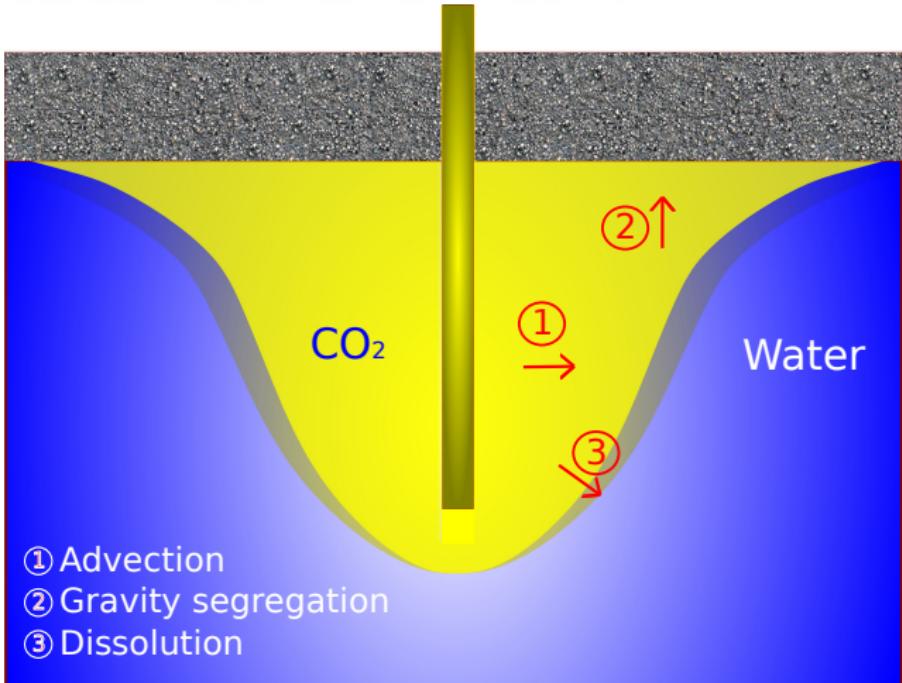
$$v_\alpha = -\frac{K_{e\alpha}}{\mu_\alpha} \cdot (\nabla P_\alpha + \rho_\alpha g \nabla Z) \quad (2)$$

Here,  $K_{e\alpha}$  is the effective permeability for phase  $\alpha$  and can be calculated from:

$$K_{e\alpha} = K_{abs} K_{r\alpha}, \quad (3)$$

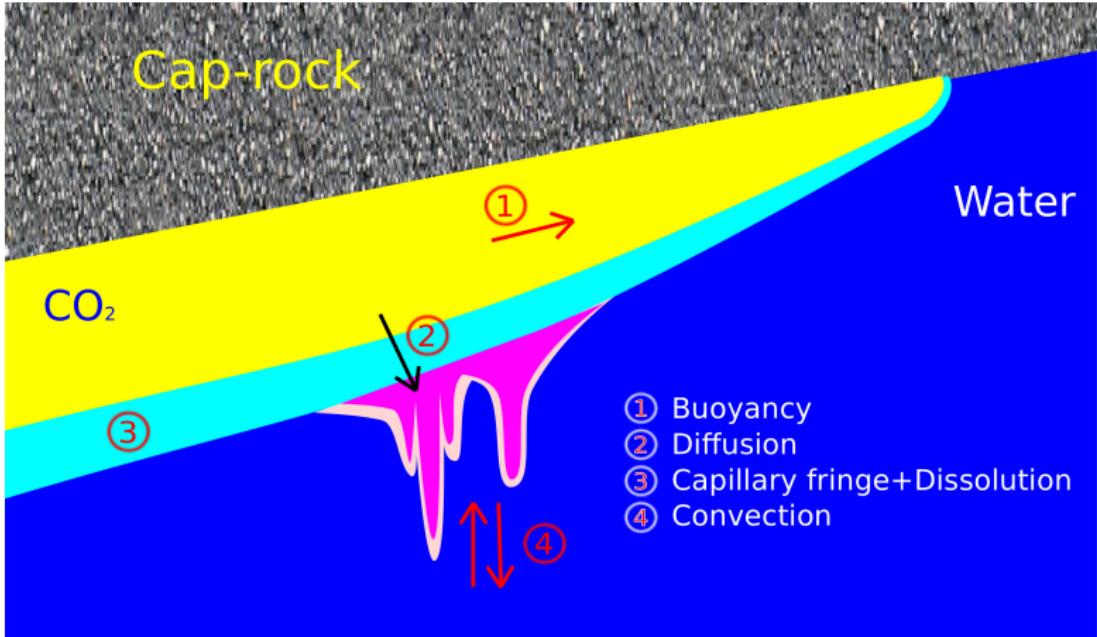
where  $K_{abs}$  is the absolute rock permeability and  $K_{r\alpha}$  is the relative permeability of phase  $\alpha$ .  $P_\alpha$  is the phase pressure,  $\rho_\alpha$  is the phase density,  $g$  is the gravitational acceleration, and  $Z$  is the elevation.

# Injection And Early Migration



Viscous and gravity forces are the two major forces acting on the region around the injector during injection.

# Long Term Migration



The injected CO<sub>2</sub> volume in the geological formation will travel below the sealing cap by buoyancy forces.

# Flow Solver



**Eclipse Black-Oil** flow solver is for the study:

The equation governing the flow into cell  $a$  from the neighboring cell  $b$  is as follows:

$$F_{ab\alpha} = T_{ab} M_{a\alpha} \Delta\psi_\alpha. \quad (4)$$

Here,  $\Delta\psi_\alpha$  is the potential term difference between two cell centers. The transmissibility is:

$$T_{ab} = \left( \frac{1}{T_a} + \frac{1}{T_b} \right)^{-1}. \quad (5)$$

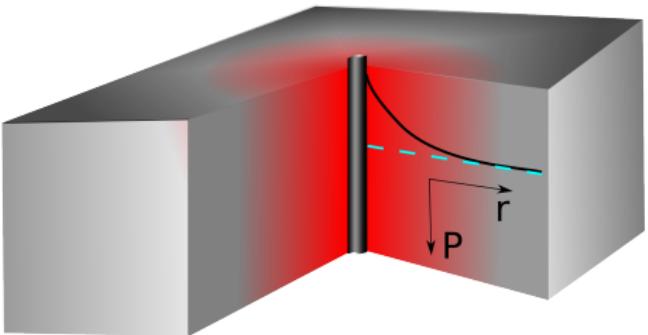
The mobility:

$$M_{a\alpha} = \frac{k_{r\alpha}}{B_\alpha \mu_\alpha}, \quad (6)$$

where  $B_\alpha$  is the formation volume factor:

$$B_\alpha = \frac{\text{Volume at surface condition}}{\text{Volume at formation condition}} = \frac{V_{s\alpha}}{V_{r\alpha}}. \quad (7)$$

# Well Modeling



Flow equation for phase  $\alpha$  through the well:

$$\eta_\alpha = T_w \cdot M_\alpha \cdot [P_w - P_i]. \quad (8)$$

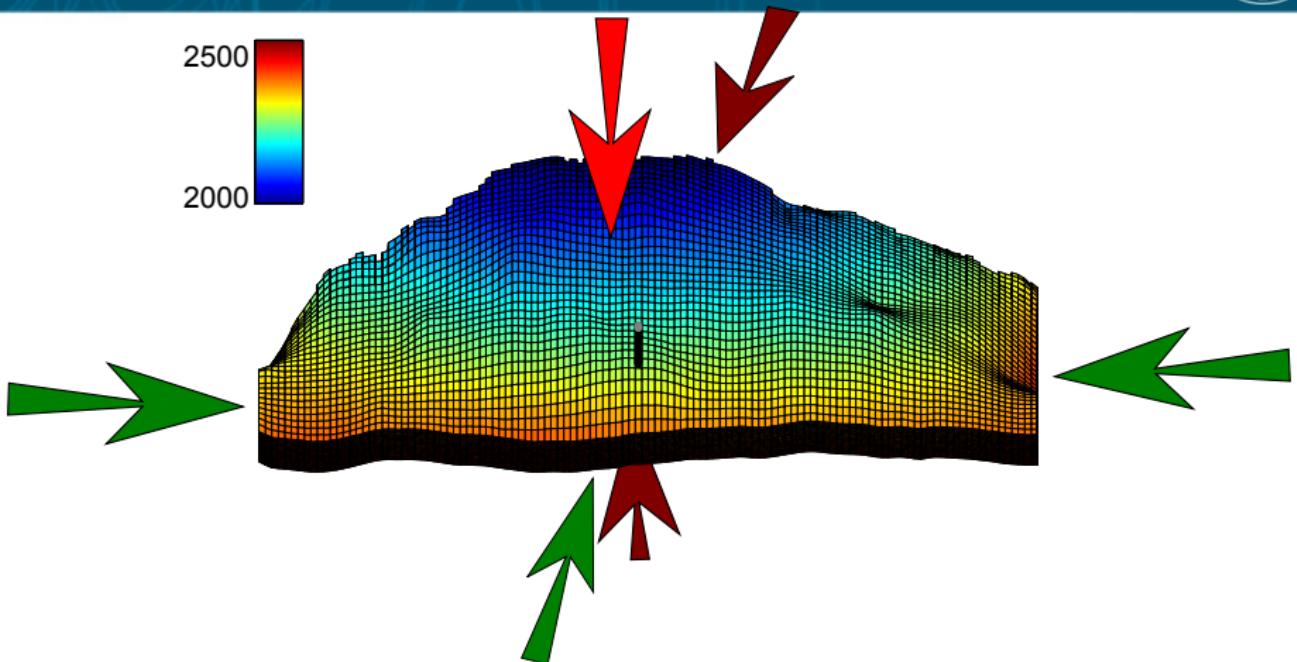
Here,  $P_w$  is the injector bottom-hole pressure,  $P_i$  is the cell pressure,  $T_w$  is the transmissibility between the cell and the injection well-bore, and  $M_\alpha$  is the mobility of injection flow into the cell.

# Simulation Model



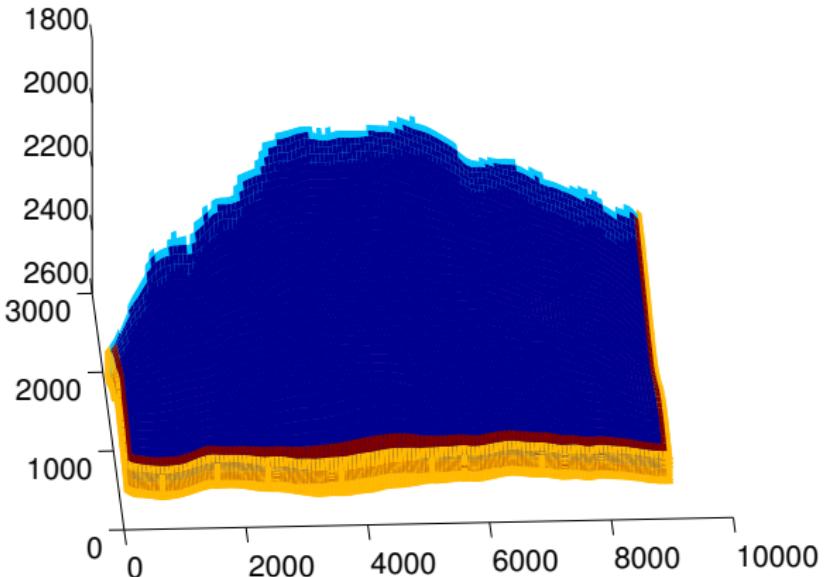
Parameter	Fine Scale	Coarse Scale
Number of cells in the x direction	80	40
Number of cells in the y direction	240	120
Number of cells in the z direction	80	20
Number of total cells	1,500,000	96,000
Number of active cells	1,500,000	79,000
Model x dimension	3 km	3 km
Model y dimension	9 km	9 km
Model z dimension	80 m	80 m
Cell x dimension	37.5 m	75 m
Cell y dimension	37.5 m	75 m
Cell z dimension	1 m	4 m

# Boundary Condition



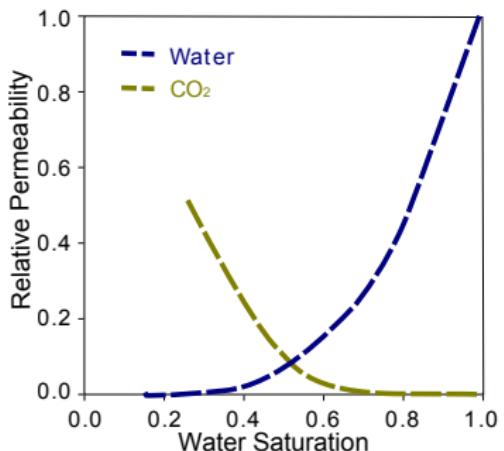
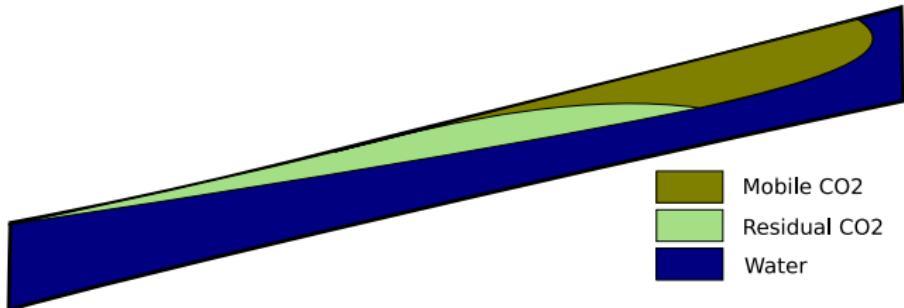
In the models used for flow simulation, the top, bottom, and upper side boundaries are closed and the rest are open to the flow.

# Boundary Condition



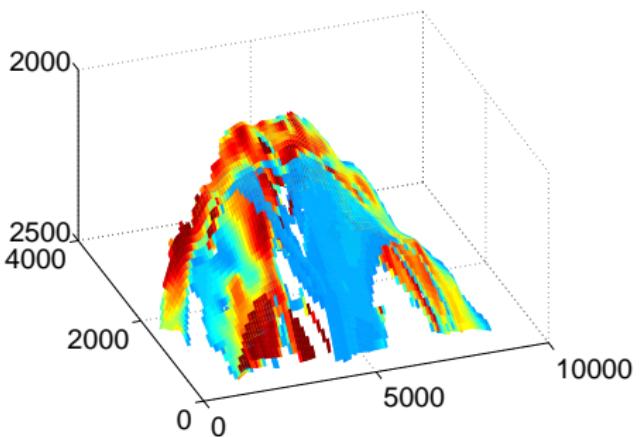
In the models used for flow simulation, the top, bottom, and upper side boundaries are closed and the rest are open to the flow.

# Mobile and Residual Volumes



**Mobile and residual volumes:** If the CO<sub>2</sub> saturation is below the critical value, it will be immobile in the bulk flow. Less mobile CO<sub>2</sub> means less risk of leakage.

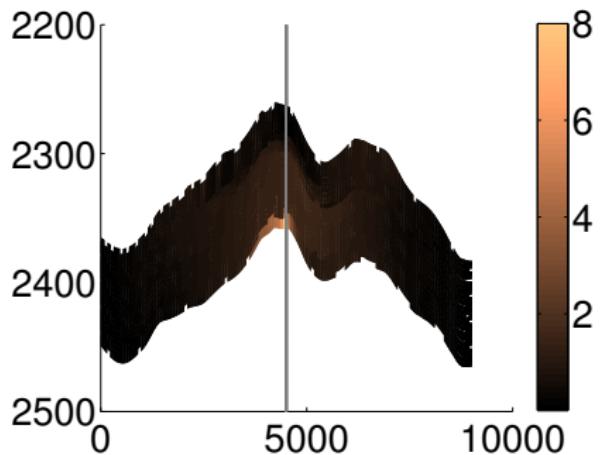
# CO<sub>2</sub> Plume Spatial Distribution



**CO<sub>2</sub> plumes:** The injected CO<sub>2</sub> volume is considered for:

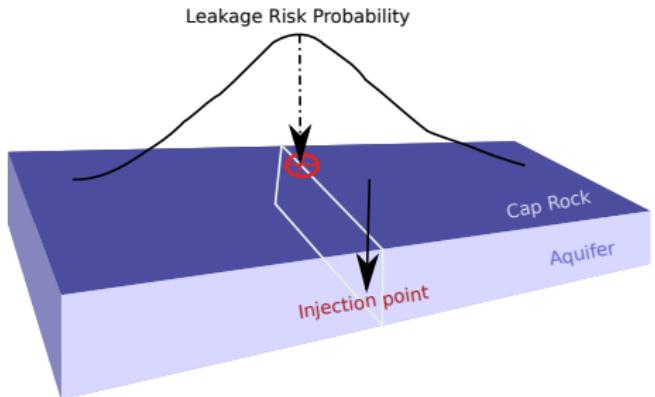
- Largest plume volume
- Number of plumes

# Pressure Behavior



**Average aquifer pressure:** The pressure response in general shows a sharp jump at the start of injection and a declining trend during the injection and plume migration.

# Leakage Risk



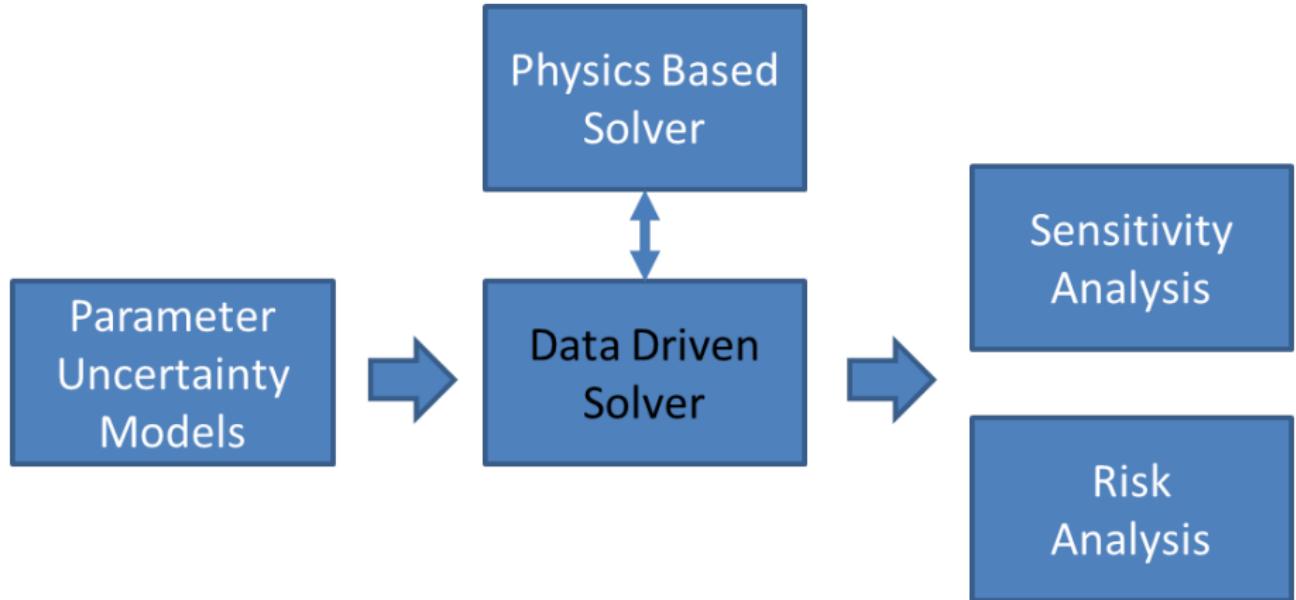
**Leakage risk:** We define the probability of leakage as a measure of the relative weakness of the cap-rock and the medium.



## Section 4

### Sensitivity and Risk Analysis

# Stochastic Analysis



# Arbitrary Polynomial Chaos Expansion



The response of the system can be expanded into the space of approximating polynomial basis. This expression is specified by constant coefficients  $c_i$ :

$$\Gamma \approx \sum_{i=1}^{n_c} c_i \Pi_i(\Theta). \quad (9)$$

Here,  $n_c$  is the number of expansion terms,  $c_i$  are the expansion coefficients, and  $\Pi_i$  are the multi-dimensional polynomials for the variables  $\Theta = [\theta_1, \dots, \theta_n]$ .

# Sensitivity Analysis

**Sobol indices method:** Assume that we break the system output into components:

$$\Gamma = \Gamma_0 + \sum_i \Gamma_i + \sum_{i < j} \Gamma_{ij} + \dots \quad (10)$$

A single index shows dependency to a specific input variable:

$$S_i = \frac{V[E(\Gamma | \theta_i)]}{V(\Gamma)}, \quad (11)$$

where  $E(\Gamma | \theta_i)$  is the conditional expectation of output  $\Gamma$  given  $\theta_i$  and  $V$  is the variance operator.

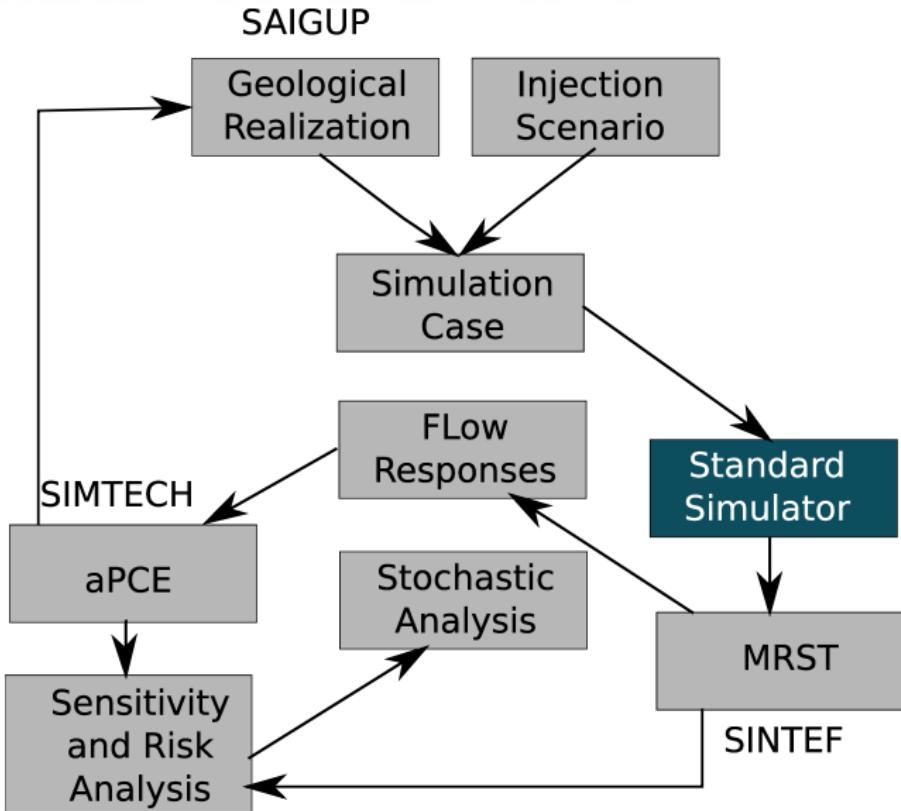
# Risk Analysis



Risk  $R$  of a process is quantitatively defined as the consequence  $C$  caused by the process multiplied by the probability  $P$  of that consequence to happen:

$$R = P \times C. \quad (12)$$

# Workflow Implementation





## Section 5

### Scientific Results

# Scientific Results



- **Paper I:** Impact of geological heterogeneity on early-stage CO<sub>2</sub> plume migration: CO<sub>2</sub> spatial distribution sensitivity study
  - ACM conference in Edinburgh, 2010.
  - CMWR conference in Barcelona, 2010.
  - ECMOR XII, Oxford, 2010.
  - NUPUS meeting in Freudenstadt, 2011.
  - Submitted to the Groundwater journal, 2014.
- **Paper II:** Geological storage of CO<sub>2</sub>: heterogeneity impact on pressure behavior
  - Submitted to the International Journal of Greenhouse Gas Control, 2014.
- **Paper III:** Geological storage of CO<sub>2</sub>: global sensitivity analysis and risk assessment using the arbitrary polynomial chaos expansion
  - European Geosciences Union (EGU) General Assembly, Vienna, 2012, Geophysical Research Abstracts., Vol. 14, EGU2012-9243.
  - Published in the International Journal of Greenhouse Gas Control, in May 2013, <http://dx.doi.org/10.1016/j.ijggc.2013.03.023>.

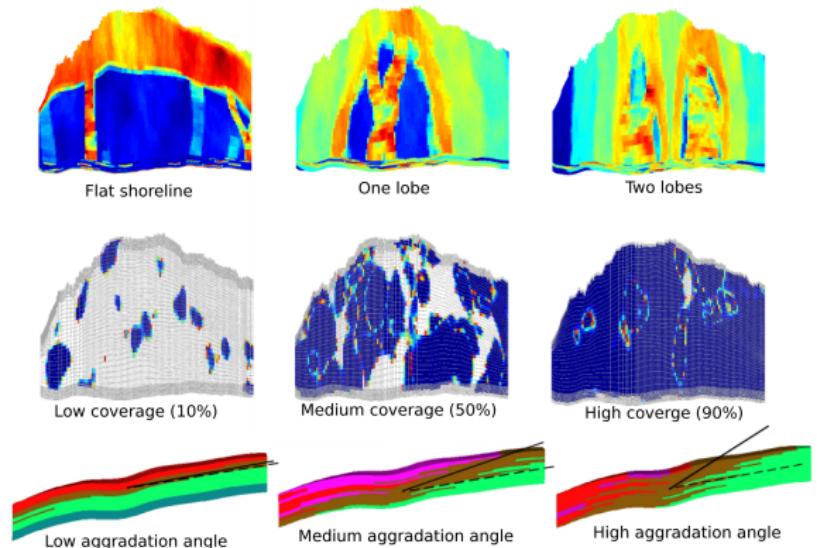
# Paper I: Objectives



The goal of this study is to

- Assess the impact of heterogeneity on the injection and early migration of CO<sub>2</sub> in aquifers.
- Investigate the effect of linear relative permeability assumption.
- Perform sensitivity analysis and rank geological parameters.

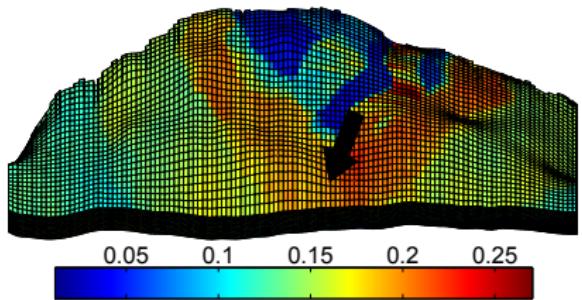
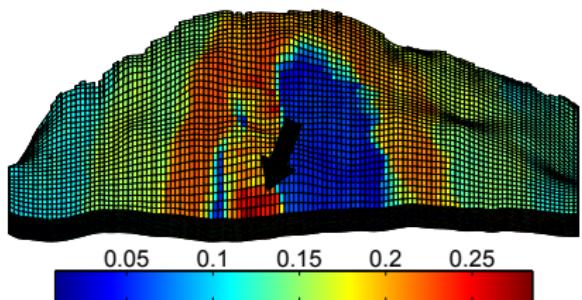
# Paper I: Geological Setup



## Geological parameters:

- Lobosity
- Barriers coverage
- Aggregation angle
- Progradation direction
- Faults

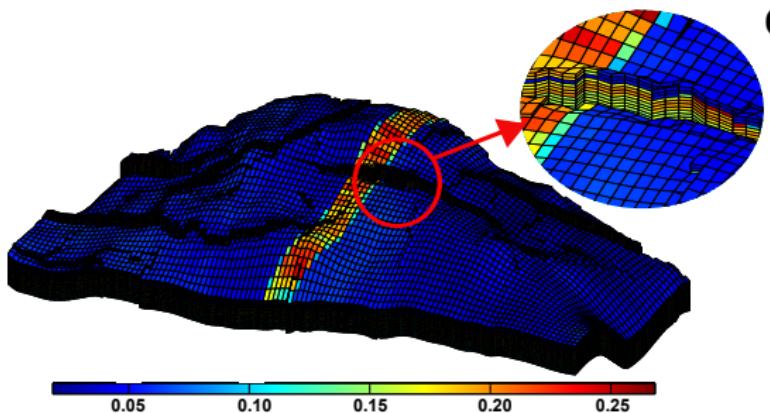
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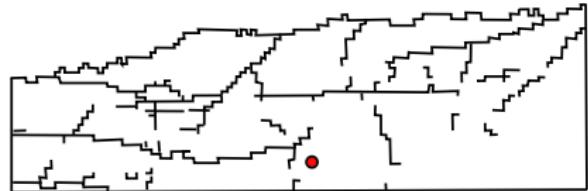
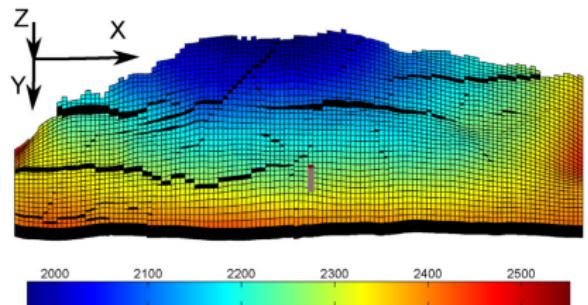
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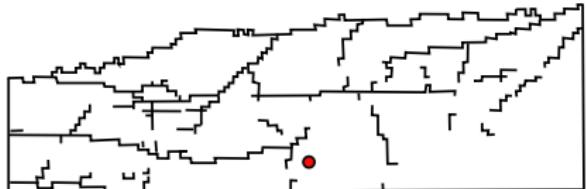
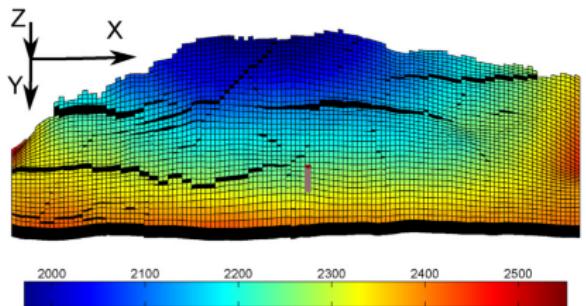
# Paper I: Simulation Scenarios



## Simulation setup:

- Injection via one well in the flank
- 30 years injection
- 70 years early migration study
- Total injection:  $4 \times 10^7 \text{ m}^3$

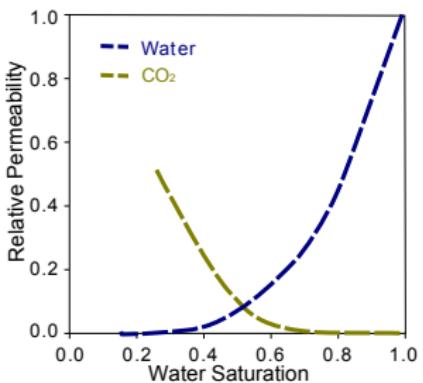
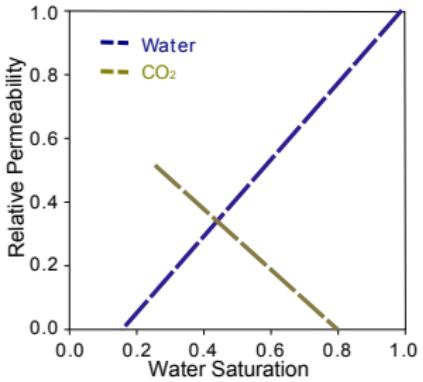
# Paper I: Simulation Scenarios



## Rock and fluid modeling:

- Supercritical CO<sub>2</sub>
  - Density: 700 kg/m<sup>3</sup>
  - Viscosity: 0.04 cP
  - Formation volume factor: 0.95 to 1.1
- Water(brine):
  - Density: 1033 kg/m<sup>3</sup>
  - Viscosity: 0.4 cP
  - Compressibility:  $3.03 \cdot 10^{-6}$  psi<sup>-1</sup>
- Rock compressibility:  $3 \cdot 10^{-7}$  psi<sup>-1</sup>

# Paper I: Simulation Scenarios



## Rock and fluid modeling:

Corey-type relative permeability functions

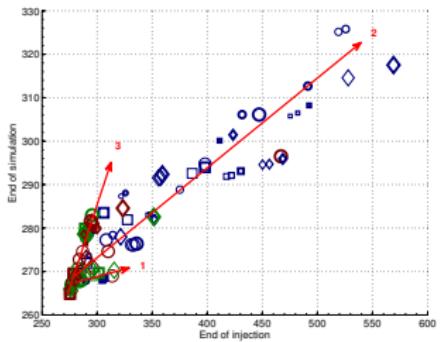
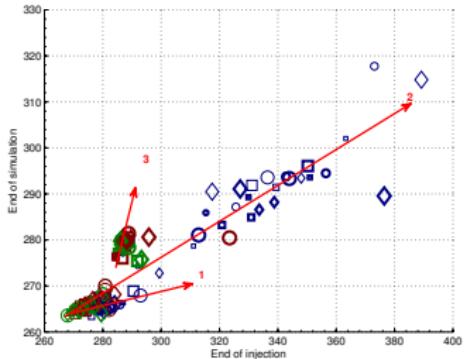
$$k_{rCO_2} = (1 - S)^\alpha,$$

$$k_{rw} = S^\alpha,$$

$$\alpha = 1, 2$$

where  $S$  denotes the saturation of brine normalized for end points 0.2 and 0.8.

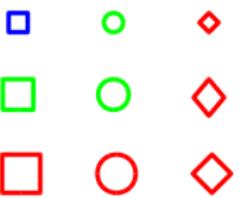
# Paper I: Results



Color: Aggradation

Shape: Lobosity

Size: Barrier



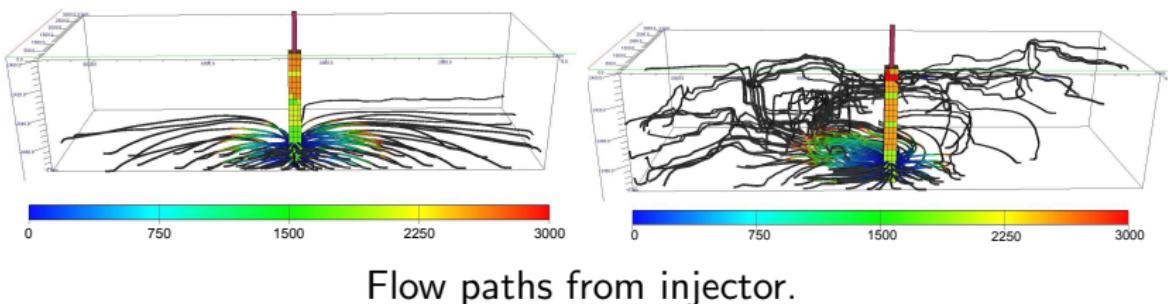
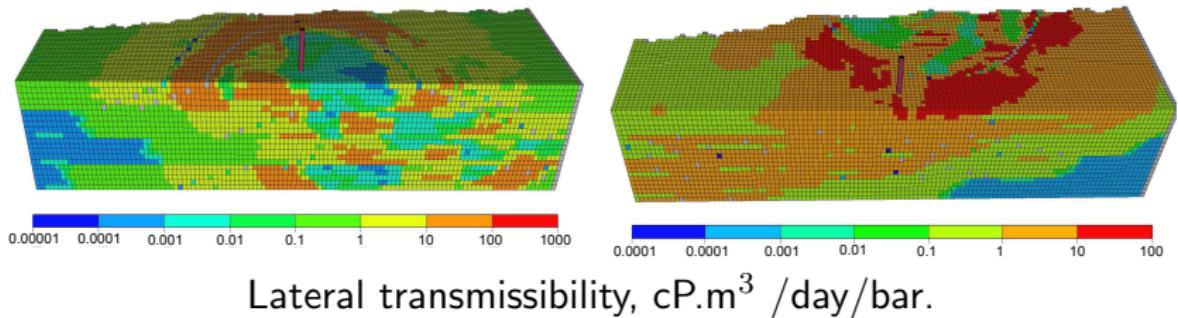
Counting → Progradation

## Average pressure:

Cross-plot of average aquifer pressure at the end of simulation versus at the end of injection for linear (top) and quadratic (bottom) relative permeabilities.

# Paper I: Results

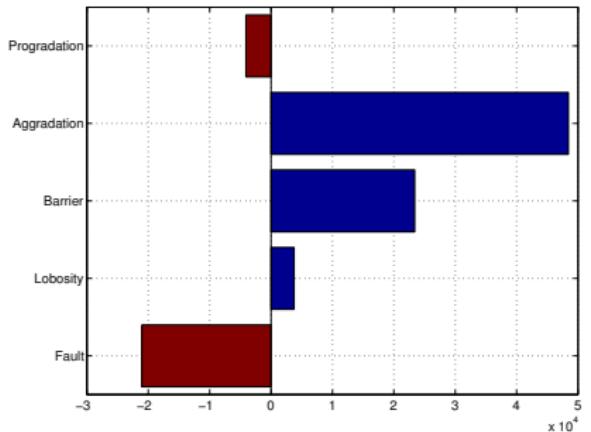
## Effect of heterogeneity on CO<sub>2</sub> flow - Progradation direction



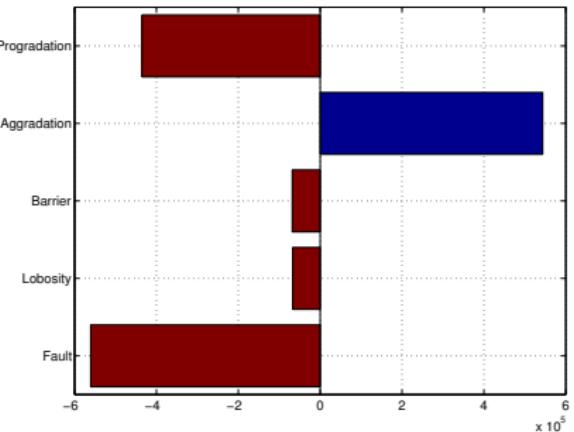
# Paper I: Results

## Sensitivity analysis

end of injection



end of simulation



residual volume of CO<sub>2</sub>



## Conclusions:

- One hundred and sixty equally probable realizations were considered.
- Linear permeability assumption is a good starting point for the study.
- Vertical resolution is important in modeling the nonlinear flow.
- Aggregation angle, faults, and progradation direction are the most influential parameters.
- Barriers play an important role during injection.

# Paper II: Objectives



The goal of this study is  
*to investigate and control the pressure buildup during injection and avoid the uncontrolled development of fractures in the medium.*

# Paper II: Outline



## Steps in the study:

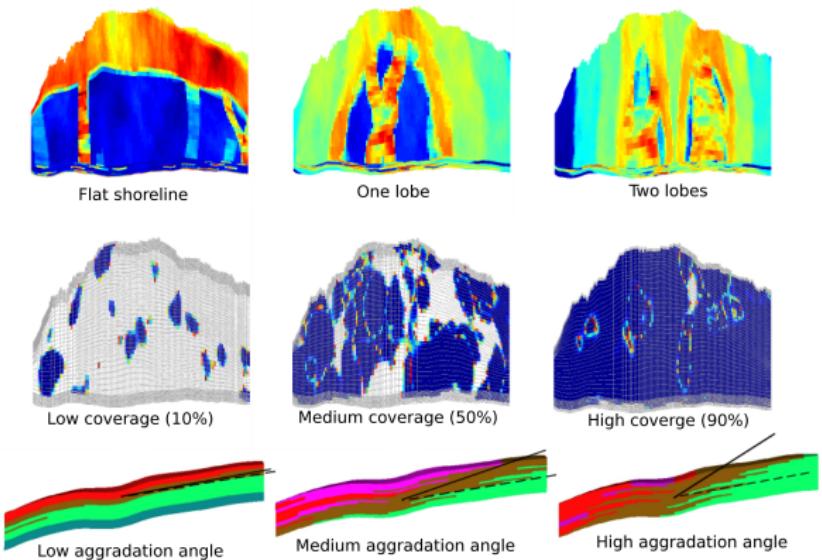
- Five geological parameters varied resulting in over 160 models
- Two injection scenarios via a single well are defined:
  - The well is on a fixed rate control.
  - The well is on a pressure constraint control.
- Specific responses are calculated to measure the propagation and rise in pressure within the medium.
- Cases are compared against their pressure behavior.

# Paper II: Geological Parameters

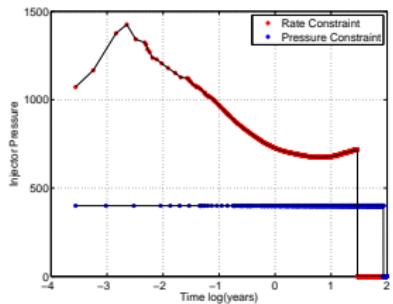


## Geological parameters:

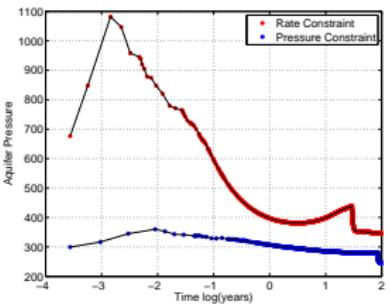
- Lobosity.
- Aggradation angle.
- Barriers coverage.
- Progradation direction.
- Faults.



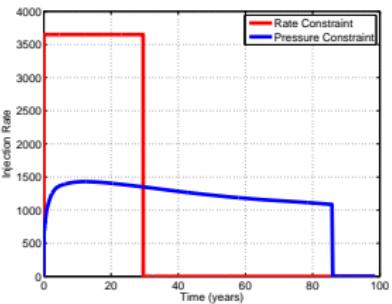
# Paper II: Injection Scenarios



(a) Pressure in the injector versus logarithm of time.



(b) Average aquifer pressure versus logarithm of time.



(c) Volumetric injection rate.

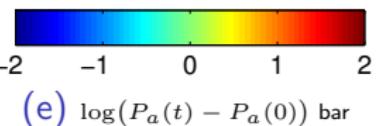
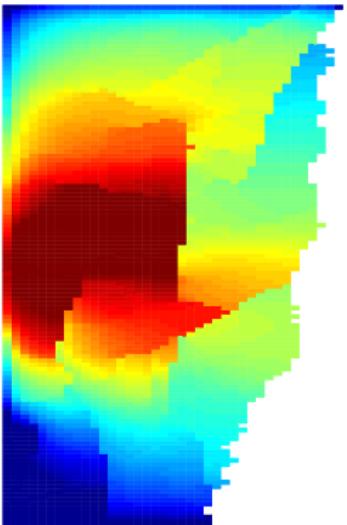
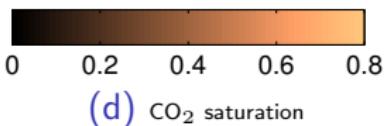
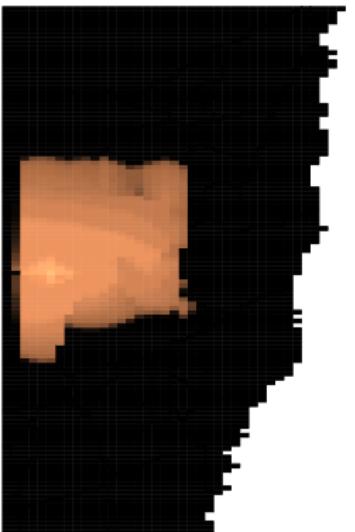
Well injection in two scenarios:

- **Rate control:** the well is set to a fixed rate of  $3650 \text{ m}^3/\text{day}$ .
- **Pressure constraint:** the well is set to operate below 400 bar.

# Paper II: Pressure Responses



Pressure perturbation travels beyond the CO<sub>2</sub> phase



# Paper II: Pressure Responses

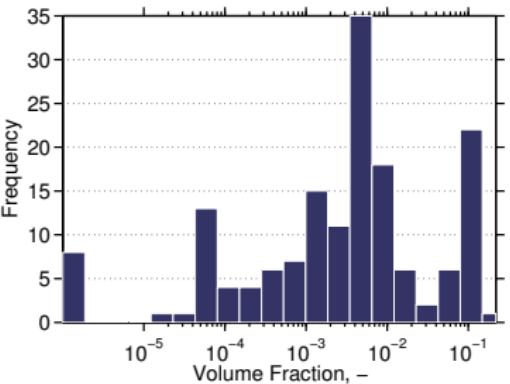
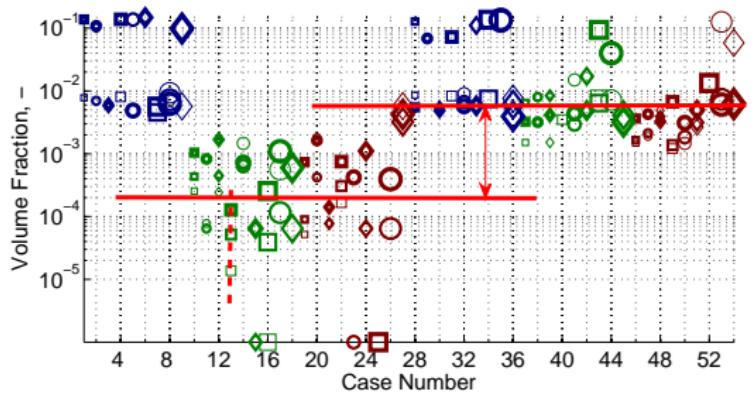


## Responses for pressure analysis

- Injection time
- Aquifer pressure
- Well pressure
- Pressurized region
- Buildup region
- Farthest pulse

# Paper II: Results

**Buildup volume fraction for all cases in the rate-constrained scenario:** Progradation and fault effects.



# Paper II: Conclusions



- The studied responses are most sensitive to **aggradation**, **progradation direction**, and **faulting**.
- **Low aggradation angles** hinder the upward movement of the CO<sub>2</sub> plume and keep the flow restricted to the geological layers in which the CO<sub>2</sub> is injected. In cases with low rock quality in the injection layers, pressure will build up in the well-bore and large volumes may be forced down-dip and out through the lower boundary.
- In the **down-dip progradation**, the majority of the region around injection point is made of low quality rock and injecting in down-dip progradation normally ends up in a higher pressure buildup and a lower injectivity.
- **Faults** change the geometrical structure of the medium and they put different layers in contact. Pressure disturbances can leak through faults to larger distances from the injection point. Closed faults can significantly reduce the injectivity quality.

# Paper III: Objectives



The goal of this study is  
*to demonstrate the application and feasibility of the arbitrary polynomial chaos expansion (aPC) for global sensitivity and probabilistic risk analysis of a typical CO<sub>2</sub> injection scenario in realistic geological realizations.*

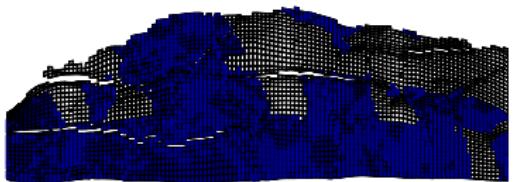
# Paper III: Outline



## Steps in the study:

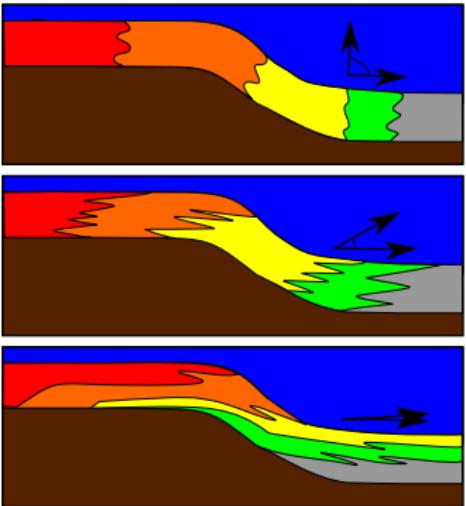
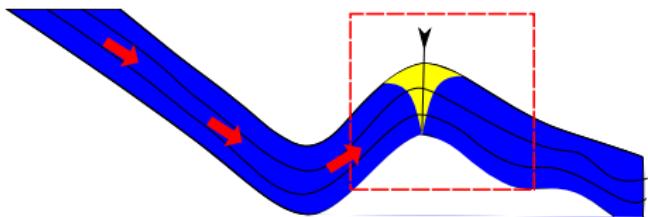
- Four geological parameters are selected for the study.
- Fixed injection rate scenario via a single well is defined.
- 15 full simulation runs are performed.
- Arbitrary polynomial chaos (aPC) is tuned to the run results.
- Sensitivity analysis is performed using the generated aPC.
- Probabilistic risk assessment is performed using the available aPC.

# Paper III: Geological Parameters



## Geological parameters:

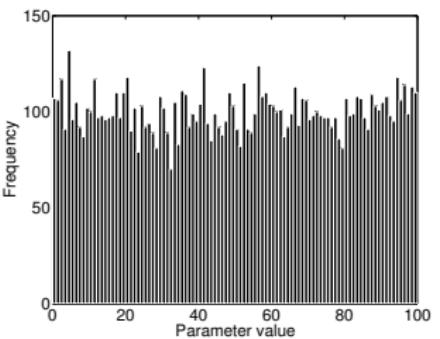
- Aggradation angle.
- Barriers coverage.
- Fault transmissibility.
- External aquifer support.



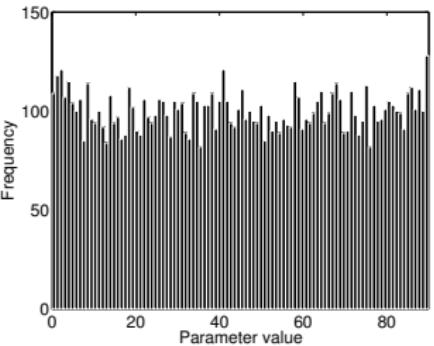
# Paper III: Parameter Uncertainty



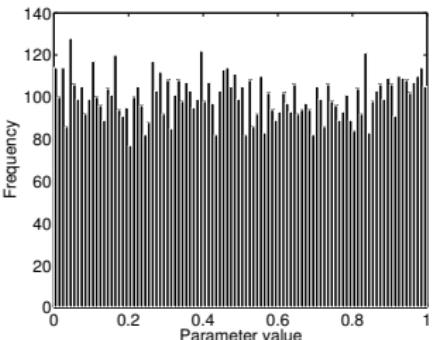
Barries



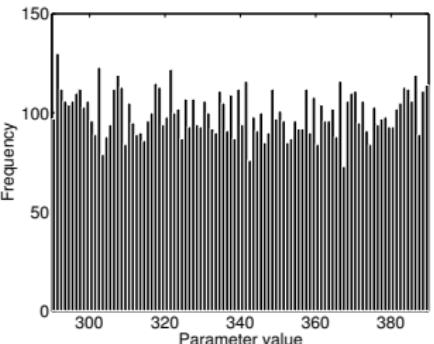
Aggradation



Faults



External Flux



# Paper III: Workflow

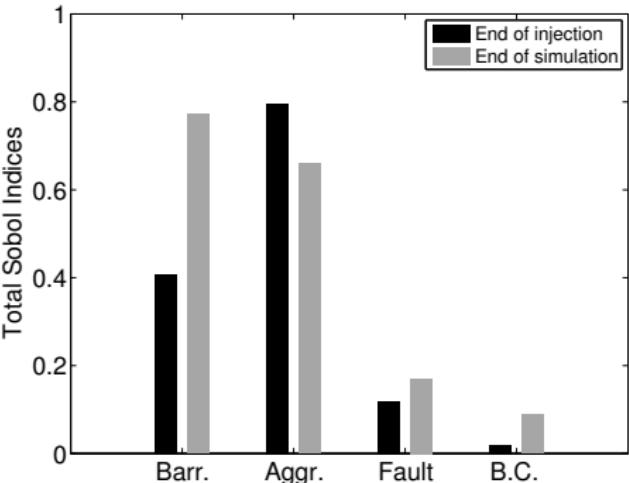
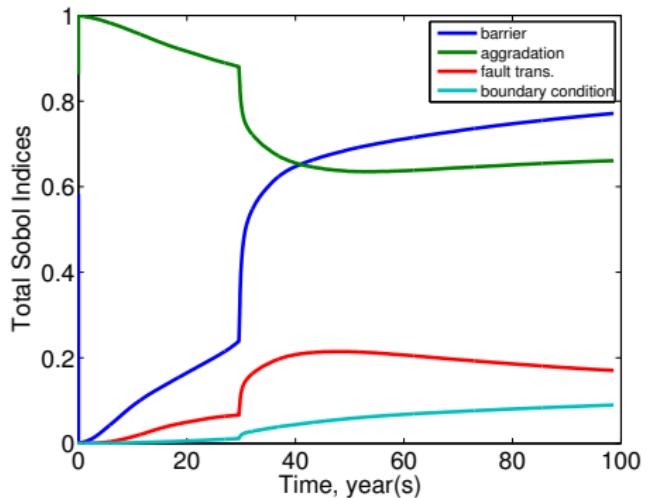


- *Use the techniques from the aPC method to derive appropriate sample points for the geological parameters.*
- *Construct geological models at these sample points.*
- Perform flow simulations for each sample point.
- Construct the proxy model.
- Perform global sensitivity analysis using the Sobol indexes method and the proxy model.
- Perform the Monte Carlo simulations using the aPC study to assess the uncertainty and risk.

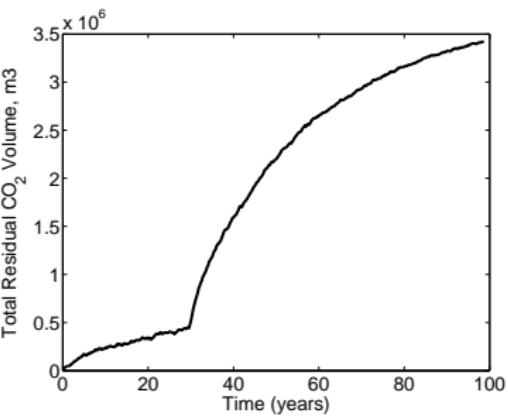
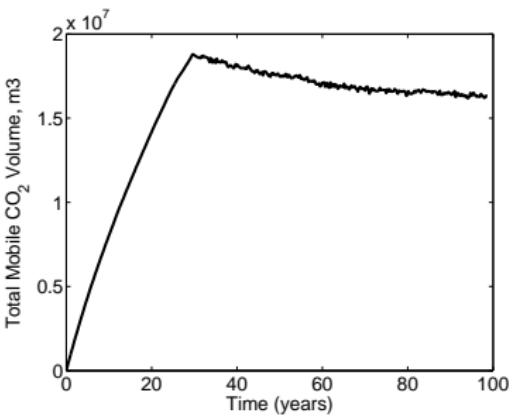
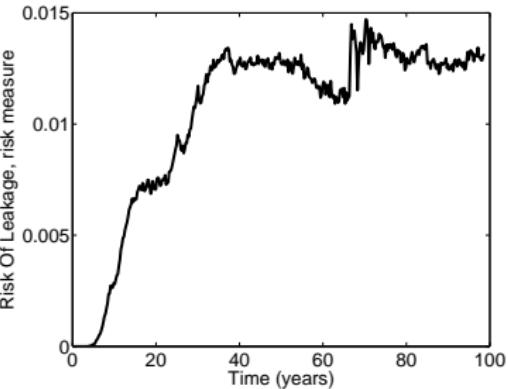
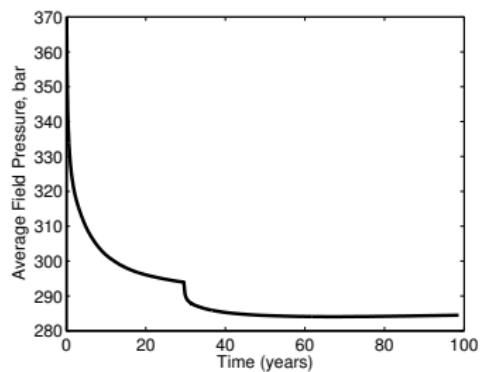
# Paper III: Global Sensitivity Analysis



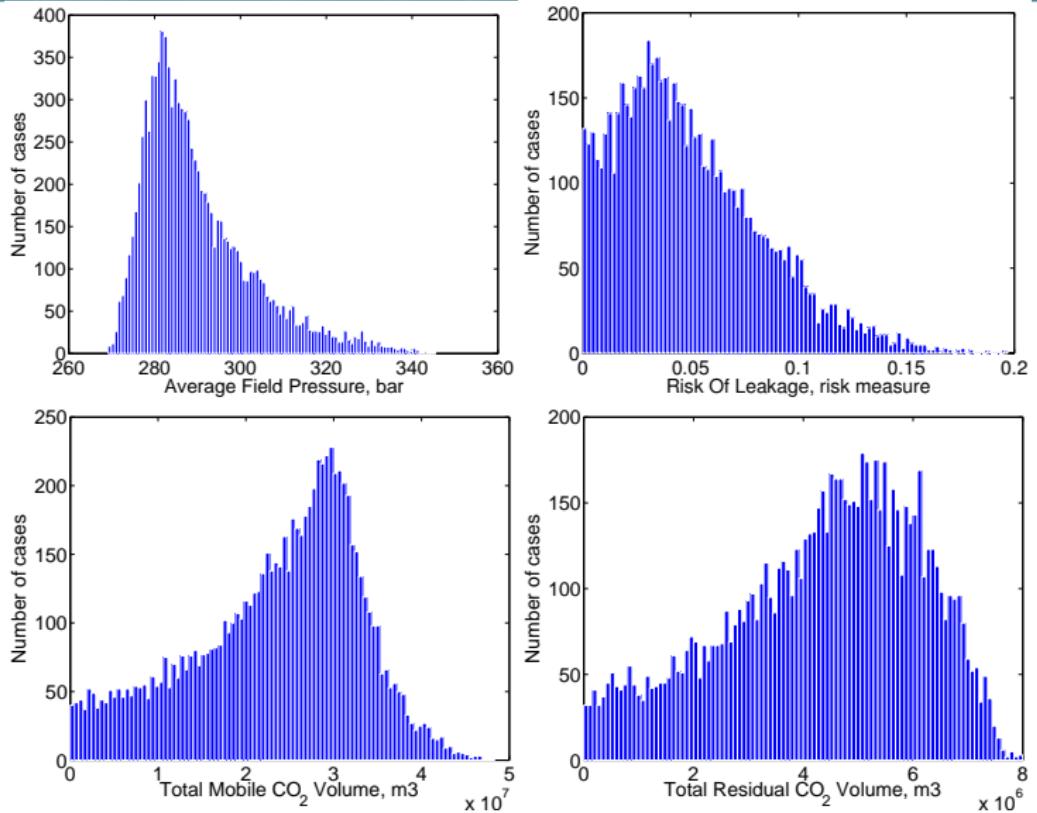
## Average CO<sub>2</sub> Pressure, Sobol Indices



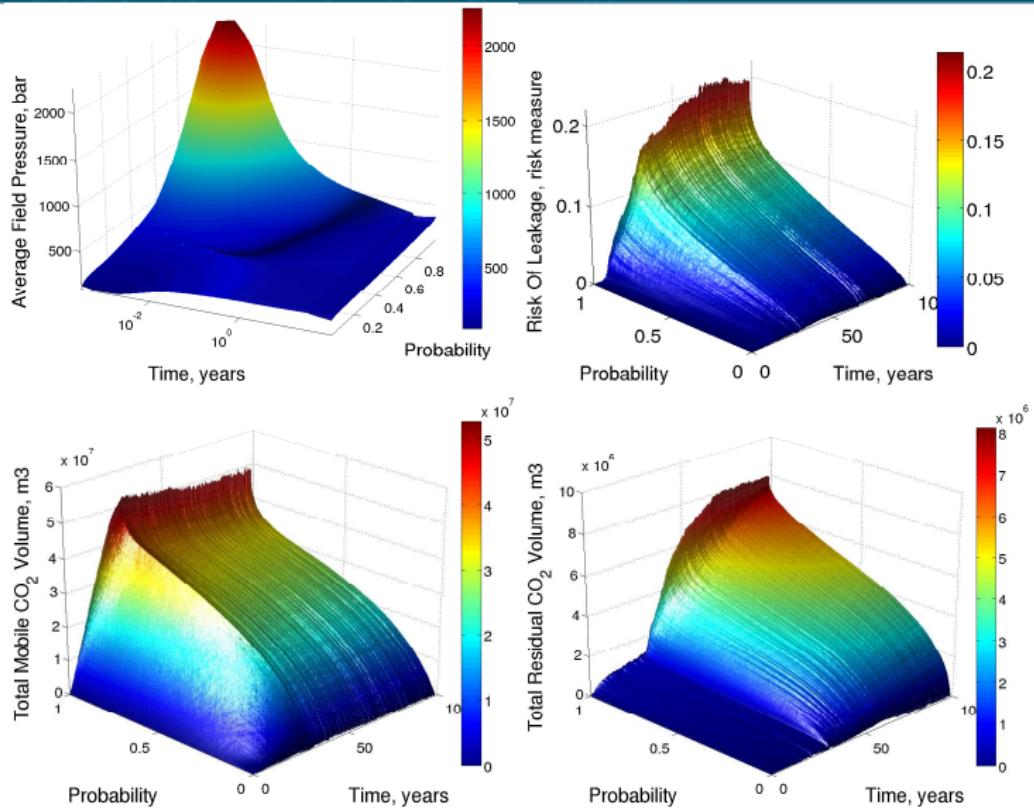
# Paper III: Expectations



# Paper III: Monte-Carlo Process



# Paper III: Probabilistic Results



# Paper III: Conclusions

- The performance of the aPC method has been satisfactory. It is very fast, compared to other stochastic methods for low-parametric systems, and this speed-up allows us to perform an extensive Monte-Carlo process on the aPC-based response surface to calculate the probability of response values throughout simulation time.
- This study was a first-time application of the aPC to study a realistically complex type of geological structural uncertainty. Based on our assessment of aPC feasibility, we can strongly encourage the use of aPC for sensitivity and risk analysis in complex situations.
- The results have shown that the most influential parameter for most of the responses is the aggradational angle of deposition layers of the considered shallow-marine aquifer. The least relevant parameter is the regional groundwater effect, especially during injection time.
- The physical and geological conclusions of this study are restricted to the probability assumptions taken here and should not be generalized to systems that are very different.



## Section 6

### General Summary

# General Summary



## Objectives:

- Assess the significance of geological modeling in early stages of CO<sub>2</sub> storage operations.
- Introduce a framework for extensive realistic sensitivity analysis and risk assessment of geological CO<sub>2</sub> storage.

## Limitations:

- Model size and boundary conditions
- Vertical grid resolution
- Uniform parameter uncertainty in the SAIGUP setup



## Section 7

### Backup Slides

# Spatial Scales



Spatial scales for CO<sub>2</sub> storage. Ranges are extracted from.

Feature	Spatial scale
Capillary fringe	10 cm ⇒ 10 m
Plume radius	10 km ⇒ 100 km
Pressure perturbation	50 km ⇒ 500 km
Migration distance	50 km ⇒ 500+ km

Celia and Nordbotten, Geological Storage of CO<sub>2</sub> Modeling Approaches for Large-Scale Simulation. Wiley, 2011.

# Temporal Scales



Temporal scales for CO<sub>2</sub> storage. Ranges are extracted from.

Feature	Temporal scale
Density segregation	1 month ⇒ 5+ years
Capillary segregation	1 year ⇒ 50 years
Injection period	5 years ⇒ 50 years
Convective mixing	20 years ⇒ 1000 years
Plume migration	few hundred years ⇒ 1000 years
Mineral reaction	500 years ⇒ 100000 years

Celia and Nordbotten, Geological Storage of CO<sub>2</sub> Modeling Approaches for Large-Scale Simulation. Wiley, 2011.

# Number of Runs

The number  $n_c$  of unknown coefficients  $c_i$  depends on the degree  $d$  of the approximating polynomial, and the number of considered parameters  $n$ :

$$n_c = \frac{(d+n)!}{d! \times n!}. \quad (13)$$

# Orthogonality Of Basis



we consider the polynomial  $P^{(k)}$  of degree  $k$  in the random variable  $\theta$ :

$$P^{(k)}(\theta) = \sum_{j=0}^k p_j^{(k)} \theta^j. \quad (14)$$

Polynomials  $P^{(k)}$  are orthogonal, if every pair of them fulfill the following condition:

$$\int_{I \in \Omega} P^{(l)} P^{(m)} d\tau(\theta) = \delta_{lm}, \quad (15)$$

where  $\delta$  is the Kronecker delta function and  $\tau$  is the measure for input variable space.

# Parameter Uncertainty

Equation (15) can be obtained from the solution of the following linear system of equations:

$$\begin{bmatrix} \mu_0 & \mu_1 & \dots & \mu_k \\ \mu_1 & \mu_2 & \dots & \mu_{k+1} \\ \dots & \dots & \dots & \dots \\ \mu_{k-1} & \mu_k & \dots & \mu_{2k-1} \\ 0 & 0 & \dots & 1 \end{bmatrix} \begin{bmatrix} P_0^{(k)} \\ P_1^{(k)} \\ \dots \\ P_{k-1}^{(k)} \\ P_k^{(k)} \end{bmatrix} = \begin{bmatrix} 0 \\ 0 \\ \dots \\ 0 \\ 1 \end{bmatrix}. \quad (16)$$

Here,  $\mu_k$  is the  $k^{\text{th}}$  non-central (raw) statistical moment of the random input variable, which is defined as:

$$\mu_k = \int_{\theta \in \Omega} \theta^k d\tau(\theta). \quad (17)$$

OLADYSHKIN, CLASS, HELMIG, AND NOWAK, concept for data-driven uncertainty quantification and its application to carbon dioxide storage in geological formations. Advances in Water Resources 34 (2011), 1508–1518, doi: 10.1016/j.advwatres.2011.08.005.

# Paper II: Simulation Setup

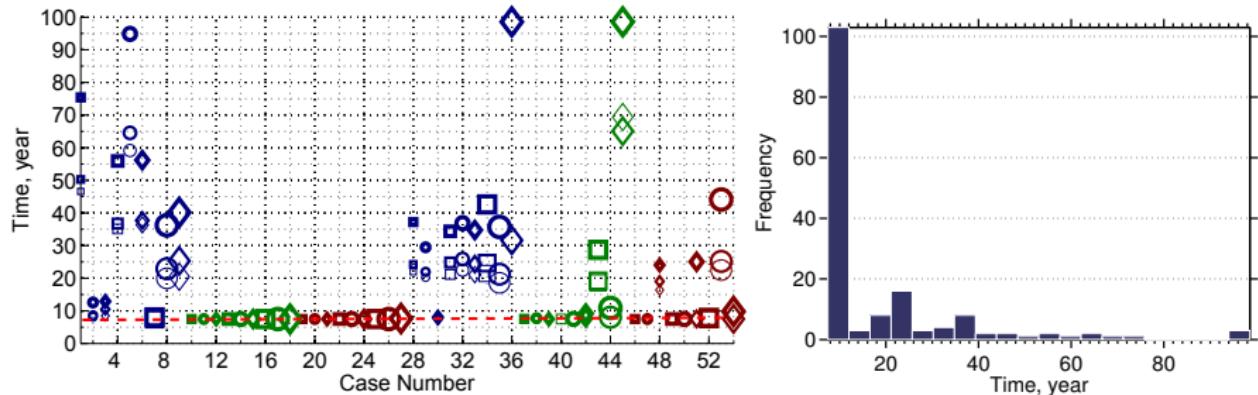


The same simulation setup is used as the previous study, except for the well operation schedule.

Parameter	Description	Value
$S_{rw}$	Residual brine saturation	0.2
$S_{rCO_2}$	Residual CO <sub>2</sub> saturation	0.2
$K_{rCO_2}$	CO <sub>2</sub> relative permeability	$(1 - S_{CO_2} - S_{rw})^2$
$K_{rw}$	Brine relative permeability	$(S_w - S_{rCO_2})^2$
$\rho_{CO_2}$	Supercritical CO <sub>2</sub> density at reference pressure	700.15 kg/m <sup>3</sup>
$\rho_w$	Brine density at reference pressure	1033 kg/m <sup>3</sup>
$C_{rock}$	Rock compressibility	$0.3 \times 10^{-6}$ 1/bar
$C_{CO_2}$	CO <sub>2</sub> compressibility	$0.375 \times 10^{-4}$ 1/bar
$C_{water}$	Water compressibility	$0.3 \times 10^{-6}$ 1/bar
$P_0$	Reference pressure	400 bar
$\mu_{CO_2}$	CO <sub>2</sub> viscosity	0.04 cP
$\mu_w$	Brine viscosity	0.4 cP
$q$	Target injection rate	3600 m <sup>3</sup> /day
$P_{cr}$	Critical well pressure	400 bar

# Paper II: Results

**Time to inject a quarter of the total specified CO<sub>2</sub> volume for all cases in the pressure-constrained scenario: Aggradation effect.**



# Paper III: Simulation Scenarios



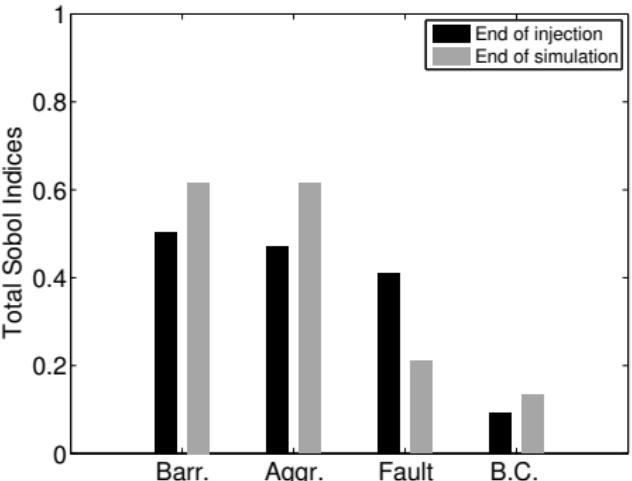
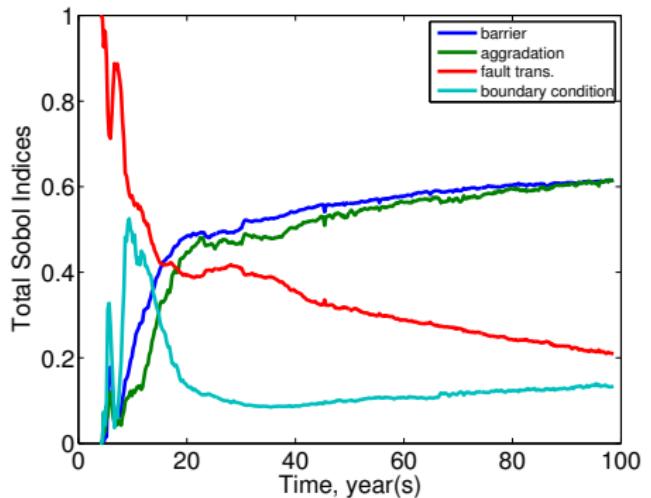
Similar to the initial study, 30 years of injection with fixed rate of 3650  $m^3/day$  via one well and 70 years of early migration are modeled.

Parameter	Value	Unit
Number of active cells in the model	78720	-
Resolution X,Y,Z	$40 \times 120 \times 20$	-
Scale X,Y,Z	$3000 \times 9000 \times 80$	m
Injection rate	3650	$m^3/day$
Initial pressure	266.5	bar
Critical CO <sub>2</sub> and water saturations	0.2	-
CO <sub>2</sub> viscosity	0.04	cp
Water viscosity	0.4	cp
Rock compressibility	0.3e-6	1/bar

# Paper III: Global Sensitivity Analysis



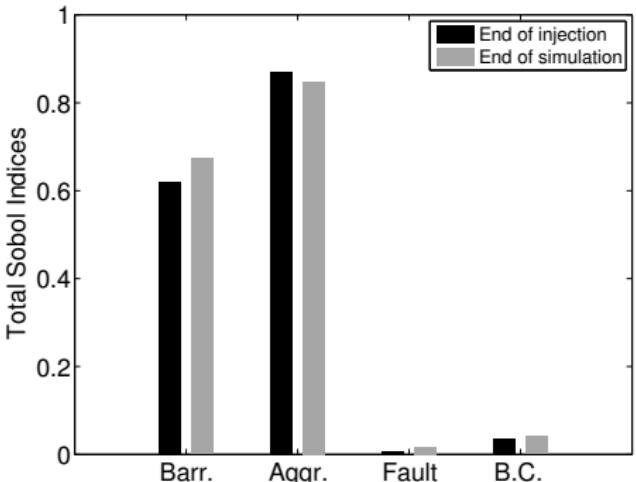
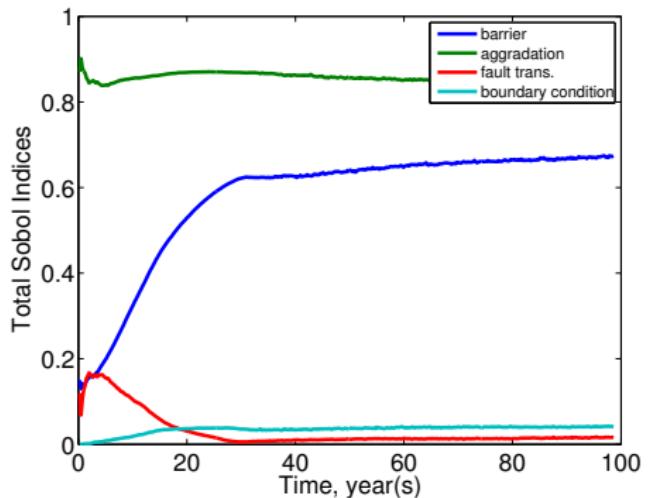
## Leakage Risk, Sobol Indices



# Paper III: Global Sensitivity Analysis



## Total Mobile CO<sub>2</sub> Volume, Sobol Indices



# Paper III: Global Sensitivity Analysis



## Total Residual CO<sub>2</sub> Volume, Sobol Indices

