Geological Storage of CO_2: Sensitivity and Risk Analysis

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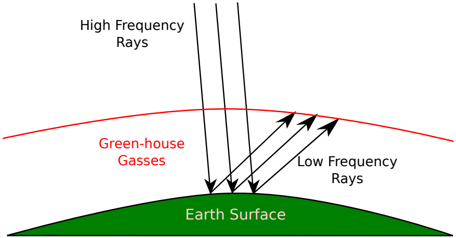
Section 1

Introduction

Underlying Goal

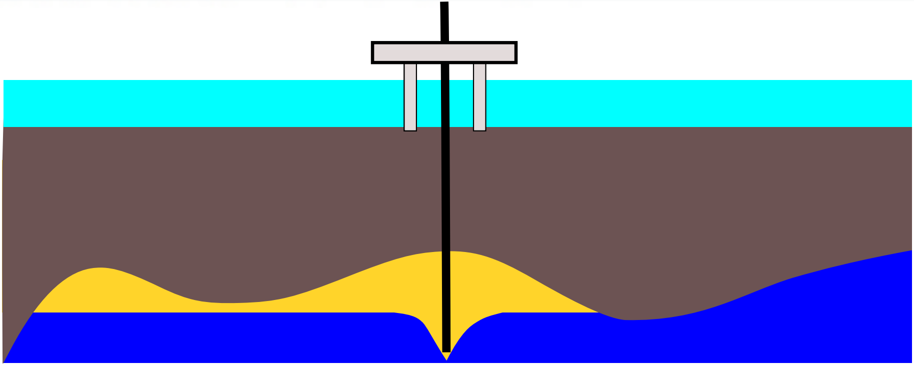
To study the impact of geological uncertainty on the success of CO_2 storage operation, and demonstrate the value of realistic geological modeling.

Green-House Gas Effect



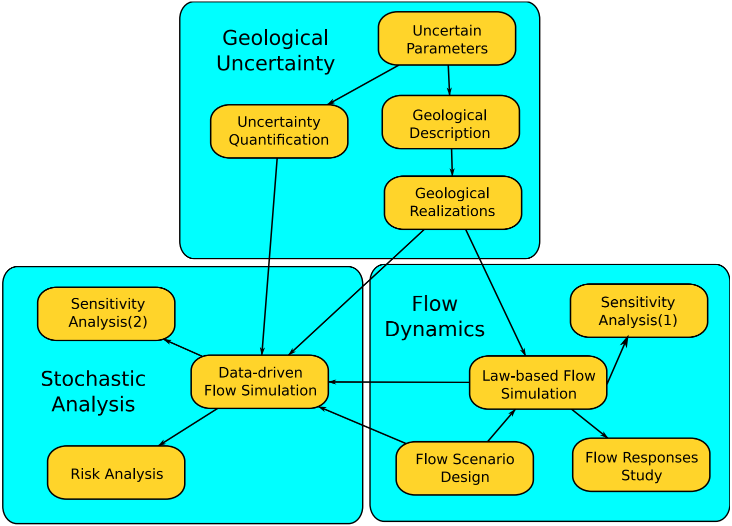
The theory of green house effect relates the earth climatic change to the trapping of heat energy by the green-house gases, and mainly carbon dioxide.

Geological CO_2 Storage



- Key technology to reduce the CO_2 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

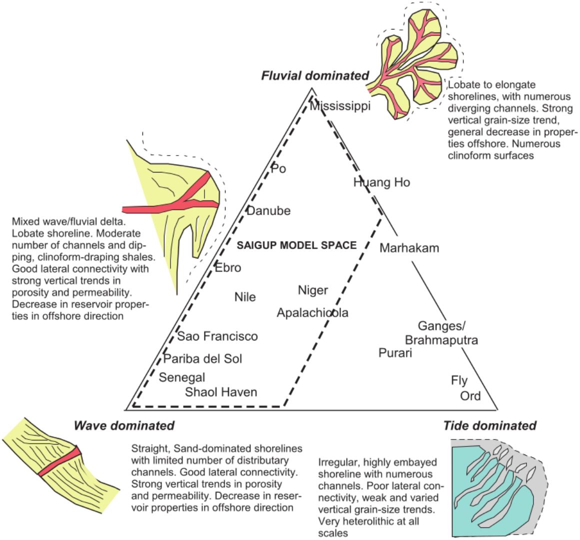
The SAIGUP

- 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.

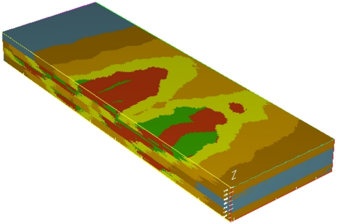
Depositional Systems

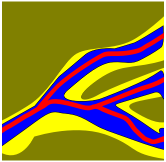
Depositional Systems

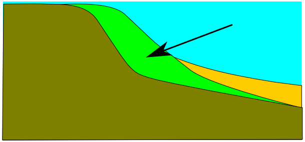
Howell et al.,Petroleum Geoscience, Vol. 14 2008, pp. 17–34



Geological Realizations

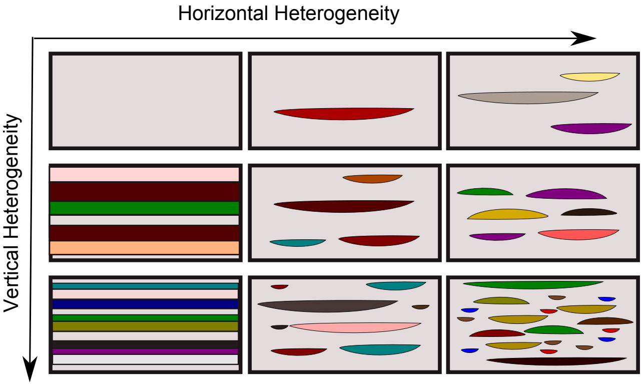






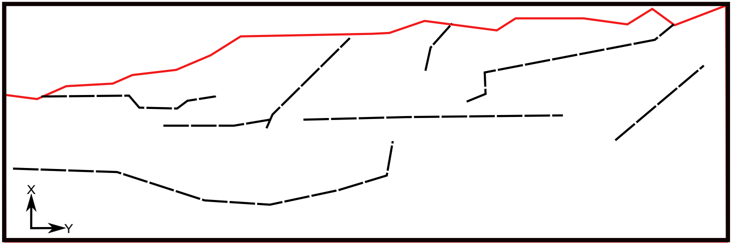
- Shallow-marine systems are considered.
- More than 160 realizations from the SAIGUP setup are used.
- Stractural and sedimentological parameters are examined.

Geological Depositional Description

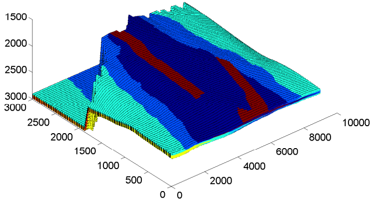


- Sedimentological variability is modeled in small and large scales.
- All models are considered in a progradational sedimentary environment.

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*.


1500
2000
2500
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3000
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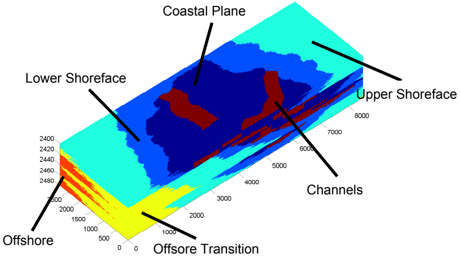
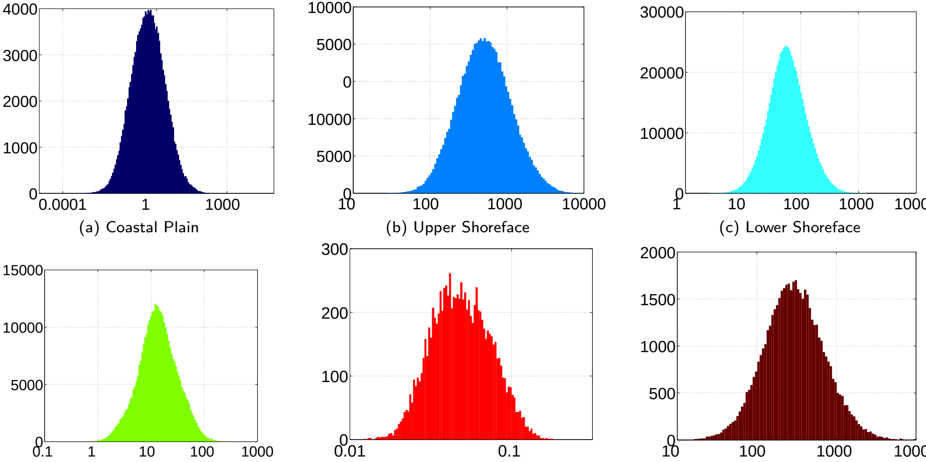
2000
4000
6000
8000
10000


Coastal Plane
Lower Shoreface
Upper Shoreface
Channels
Offshore
Offsore Transition
2400
2420
2440
2460
2480
2000
1500
1000
500
0
0
1000
2000
3000
4000
5000
7000
8000

Facies Modeling

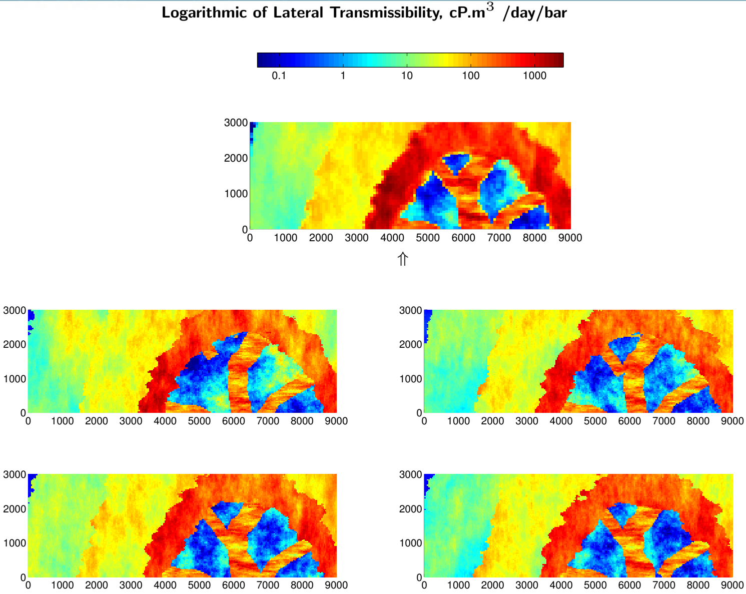
Lateral Transmissibility, cP.m^3 /day/bar



(a) Coastal Plain (b) Upper Shoreface (c) Lower Shoreface

(d) Offshore Transition (e) Offshore (f) Channels

Upscaling


Logarithmic of Lateral Transmissibility, cP.m^3 /day/bar
0.1
1
10
100
1000
3000
2000
1000
0
0 1000 2000 3000 4000 5000 6000 7000 8000 9000
⇑

Geological Parameters

Depositional:

- Lobosity
- Barriers
- Aggradation
- Progradation

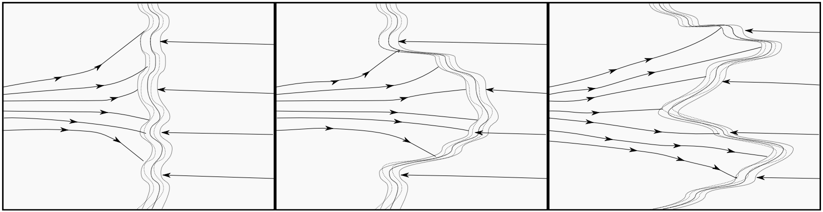
Structural:

- Unfaulted
- Faulted

Other:

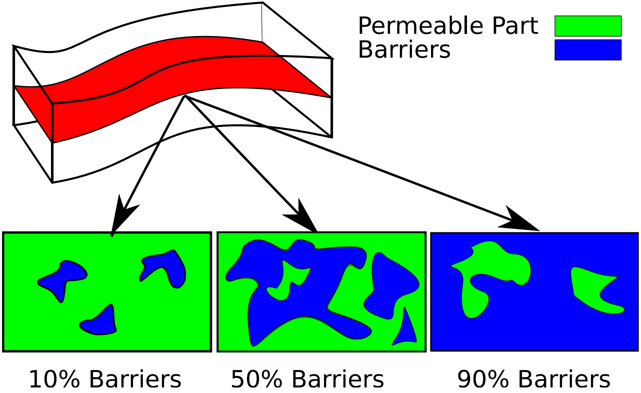
- External Aquifer

Lobosity



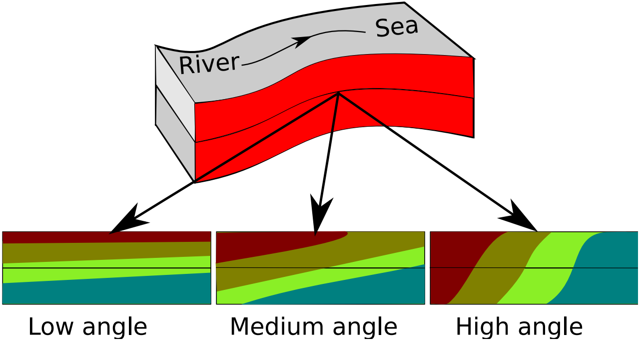
Lobosity levels are defined based on the shoreline shape, which is caused by the interplay between fluvial and wave forces.

Barriers



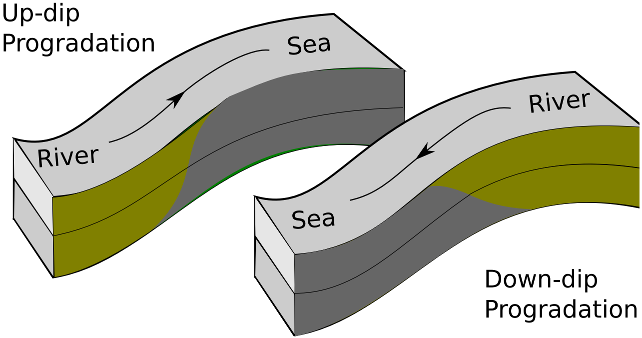
Periodic floods and flactuations in fluvial system can result in shale draped surfaces. These surfaces act as *barriers* to flow in both vertical and horizontal directions.

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

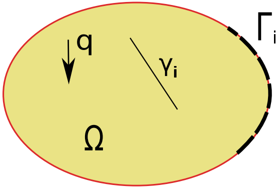


Techtonic activities in shallow marine systems can result in various orientations of river to sea depositions that is considered as *progradation* direction in the SAIGUP study.

Section 3

Flow Modeling

Two-Phase Flow Equations



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

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

for phase saturation S_α, phase flux v_α, and the source/sink term for the phase mass rate q_α. ρ_α is the phase density.

Two-Phase Flow Equations

Darcy law:

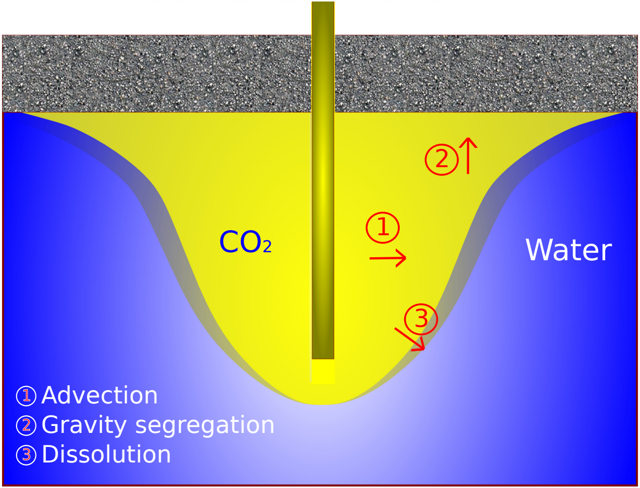
$$v_\alpha = -\frac{K_{e\alpha}}{\mu_\alpha} \cdot (\nabla P_\alpha + \rho_\alpha g \nabla Z) \tag{2}$$

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

$$K_{e\alpha} = K_{abs} K_{r\alpha}, \tag{3}$$

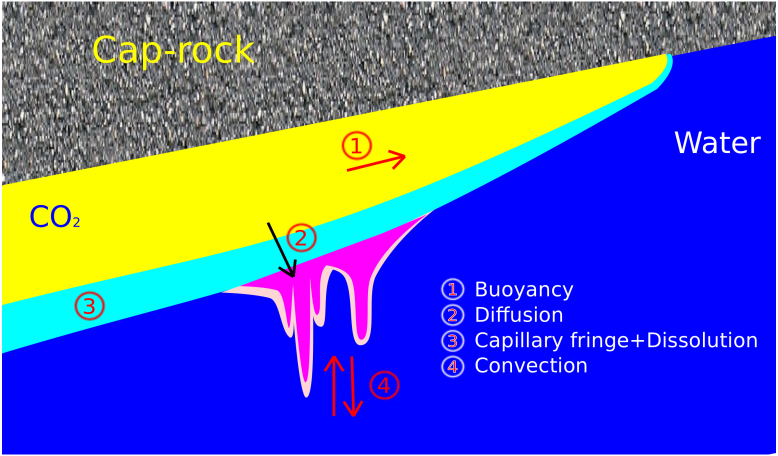
where K_{abs} is the absolute rock permeability and $K_{r\alpha}$ is the relative permeability of phase α. P_α is the phase pressure, ρ_α is the phase density, g is the gravitational acceleration, and Z is the elevation.

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 CO2 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:

$$F_{ab\alpha} = T_{ab} M_{a\alpha} \Delta\psi_{\alpha}. \tag{4}$$

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

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

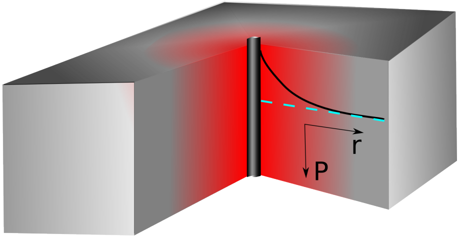
The mobility:

$$M_{a\alpha} = \frac{k_{r\alpha}}{B_{\alpha}\mu_{\alpha}}, \tag{6}$$

where B_{α} is the formation volume factor:

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

Well Modeling



Flow equation for phase α through the well:

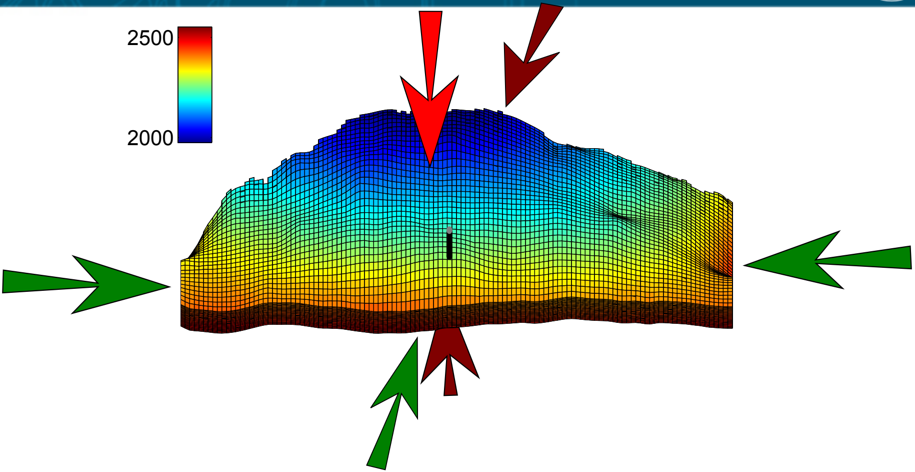
$$\eta_\alpha = T_w \cdot M_\alpha \cdot [P_w - P_i]. \tag{8}$$

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_α is the mobility of injection flow into the cell.

Simulation Model

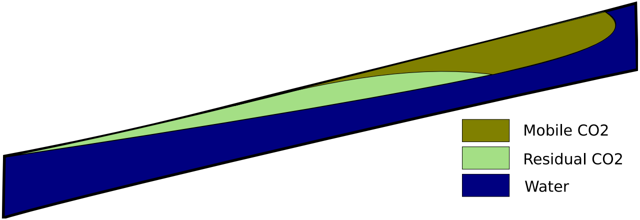
Parameter	Fine Scale	Coarse Scale
Number of cells in the x direction	80	40
Number of cells in the y direction	240	120
Number of cells in the z direction	80	20
Number of total cells	$1,500,000$	$96,000$
Number of active cells	$1,500,000$	$79,000$
Model x dimension	$3\ km$	$3\ km$
Model y dimension	$9\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

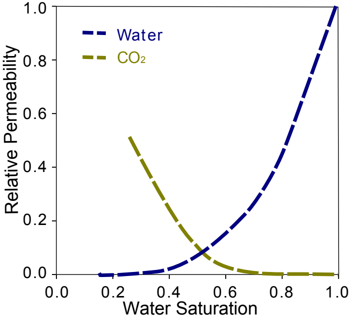
Boundary Condition



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

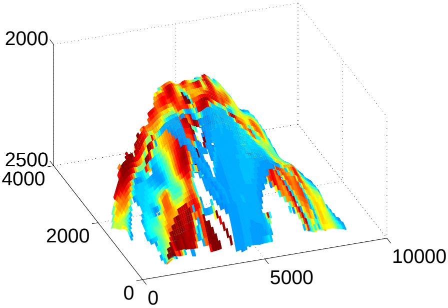
Mobile and Residual Volumes





Mobile and residual volumes: If the CO_2 saturation is below the critical value, it will be immobile in the bulk flow. Less mobile CO_2 means less risk of leakage.

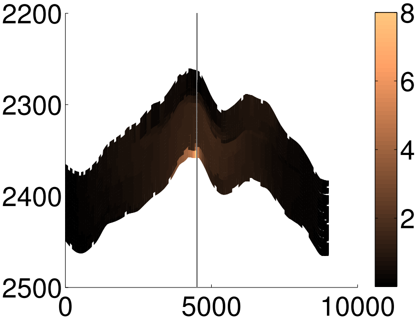
CO_2 Plume Spatial Distribution



CO_2 plumes: The injected CO_2 volume is considered for:

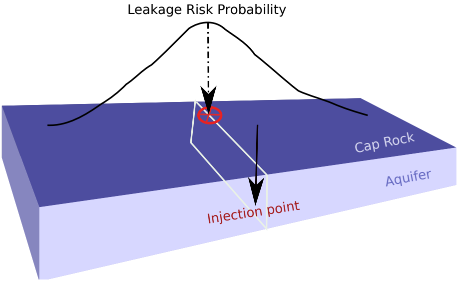
- Largest plume volume
- Number of plumes

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

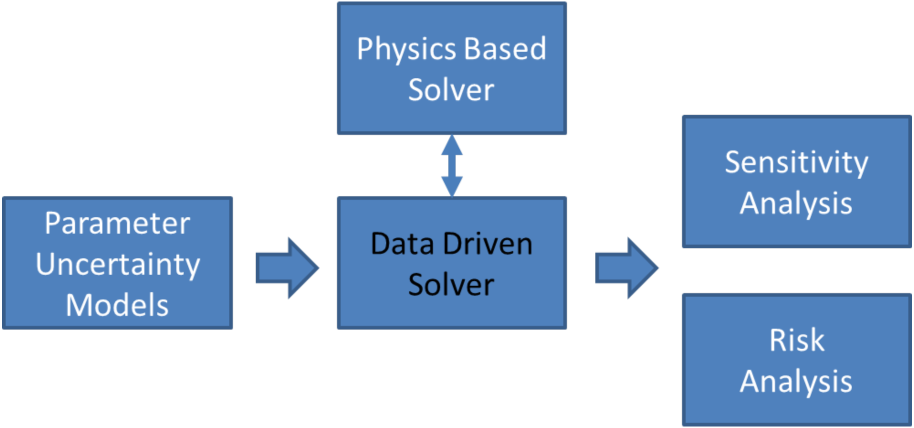


Leakage risk: We define the probability of leakage as a measure of the relative weakness of the cap-rock and the medium.

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:

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

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

Sensitivity Analysis

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

$$\Gamma = \Gamma_0 + \sum_i \Gamma_i + \sum_i \sum_{j>i} \Gamma_{ij} + ... \tag{10}$$

A single index shows dependency to a specific input variable:

$$S_i = \frac{\mathsf{V}[\mathsf{E}(\Gamma \mid \theta_i)]}{\mathsf{V}(\Gamma)}, \tag{11}$$

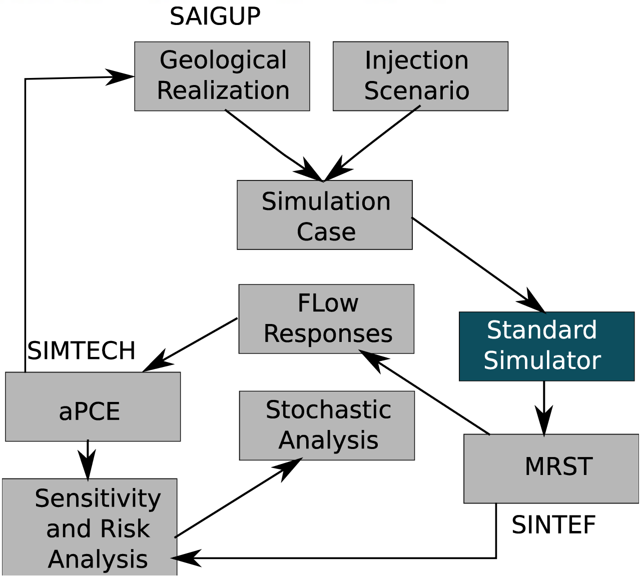
where $\mathsf{E}(\Gamma \mid \theta_i)$ is the conditional expectation of output Γ given θ_i and V is the variance operator.

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:

$$R = P \times C. \tag{12}$$

Workflow Implementation



Section 5

Scientific Results

Scientific Results

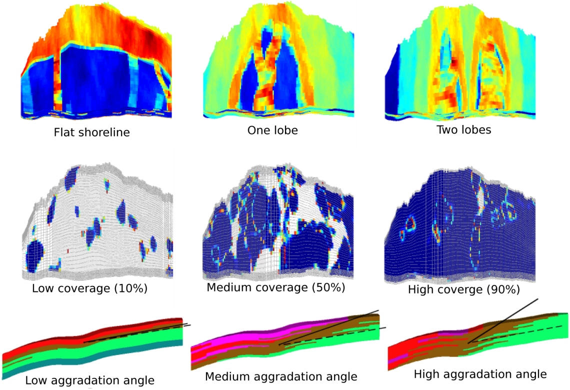
- **Paper I:** Impact of geological heterogeneity on early-stage CO_2 plume migration: CO_2 spatial distribution sensitivity study
  - ACM conference in Edinburgh, 2010.
  - CMWR conference in Barcelona, 2010.
  - ECMOR XII, Oxford, 2010.
  - NUPUS meeting in Freudenstadt, 2011.
  - Submitted to the Goundwater journal, 2014.
- **Paper II:** Geological storage of CO_2: heterogeneity impact on pressure behavior
  - Submitted to the International Journal of Greenhouse Gas Control, 2014.
- **Paper III:** Geological storage of CO_2: 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_2 in aquifers.
- Investigate the effect of relative permeability on the process.
- Perform sensitivity analysis and rank geological parameters.

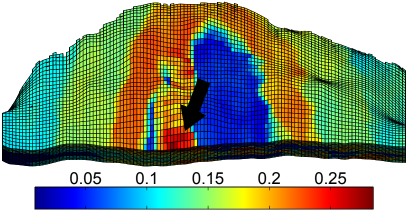
Paper I: Geological Setup

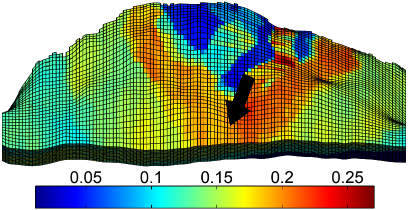


Geological parameters:

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

Paper I: Geological Setup





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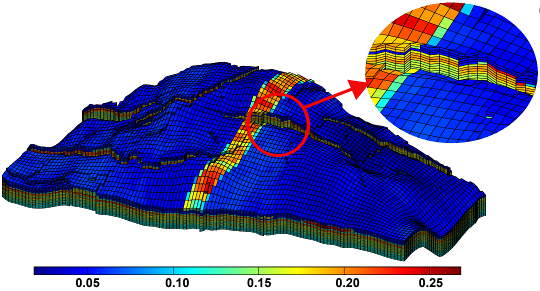
Paper I: Geological Setup



Geological parameters:

- Lobosity
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- Aggredation angle
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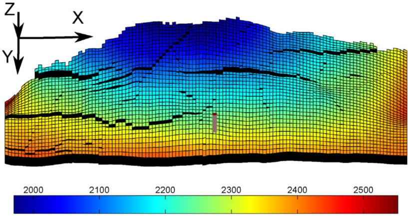
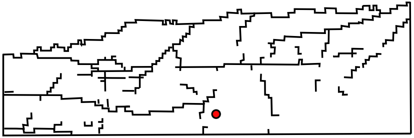
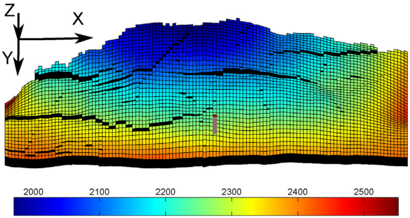
- Faults

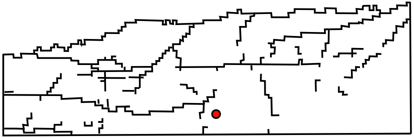




Simulation setup:

- Injection via one well in the flank
- 30 years injection
- 70 years early migration study
- Total injection: 4×10^7 m^3

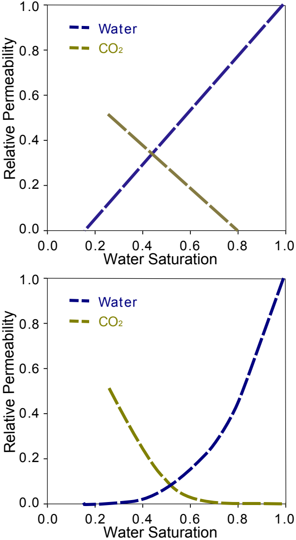




Rock and fluid modeling:

- Supercritical CO_2
  - Density: 700 kg/m^3
  - Viscosity:0.04 cP
  - Formation volume factor: 0.95 to 1.1
- Water(brine):
  - Density: 1033 kg/m^3
  - Viscosity:0.4 cP
  - Compressibility: $3.03 \cdot 10^{-6}$ psi^{-1}
- Rock compressibility: $3 \cdot 10^{-7}$psi^{-1}

Paper I: Simulation Scenarios

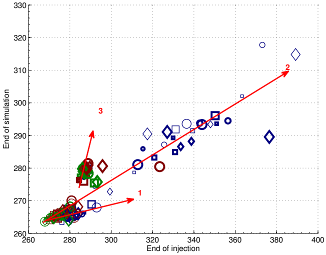


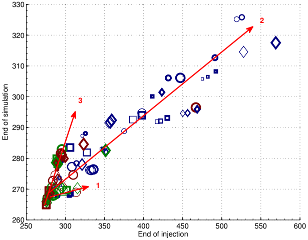
Rock and fluid modeling:
Corey-type relative permeability functions

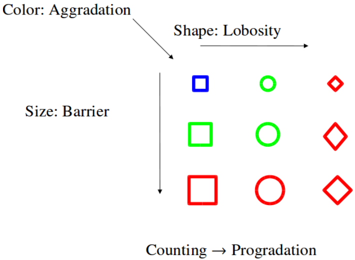
$$k_{rCO_2} = (1 - S)^{\alpha},$$
$$k_{rw} = S^{\alpha},$$
$$\alpha = 1, 2$$

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

Paper I: Results





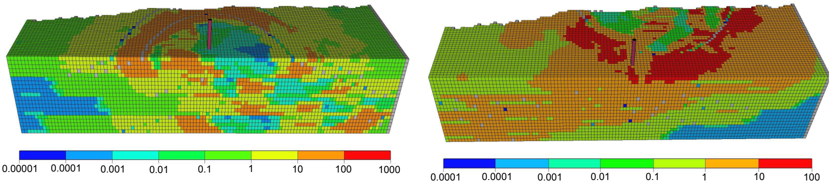


Average pressure:

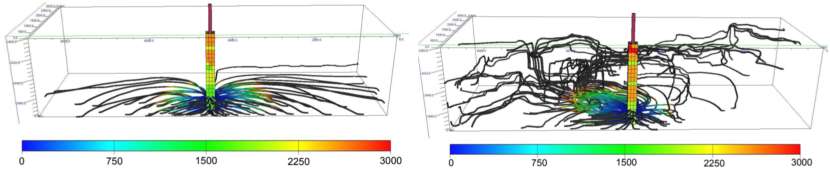
Cross-plot of average aquifer pressure at the end of simulation versus at the end of injection for linear (top) and quadratic (bottom) relative permeabilities.

Paper I: Results

Effect of heterogeneity on CO_2 flow - Progradation direction

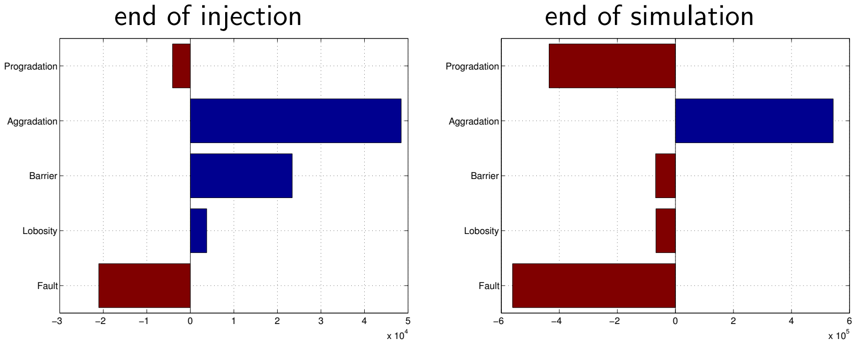


Lateral transmissibility, cP.m^3 /day/bar.



Flow paths from injector.

Sensitivity analysis



residual volume of CO_2

Paper I: Conclusions

Conlusions:

- 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.
- Aggredation angle, faults, and progradation direction are the most influencial 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

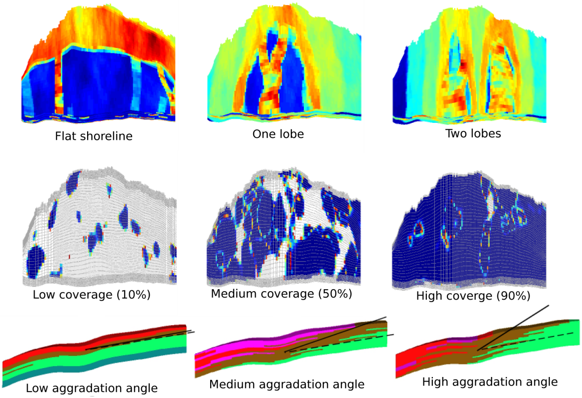
Steps in the study:

- 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.

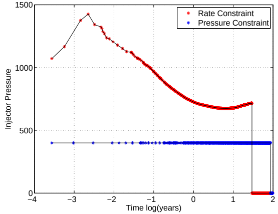
Paper II: Geological Parameters

Geological parameters:

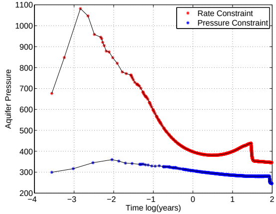
- Lobosity.
- Aggradation angle.
- Barriers coverage.
- Progradation direction.
- Faults.



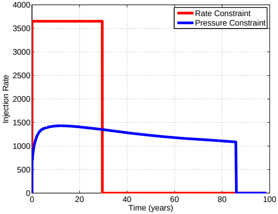
Paper II: Injection Scenarios



(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 m^3/day.
- **Pressure constraint:** the well is set to operate below 400 bar.

Pressure perturbance travels beyond the CO_2 phase

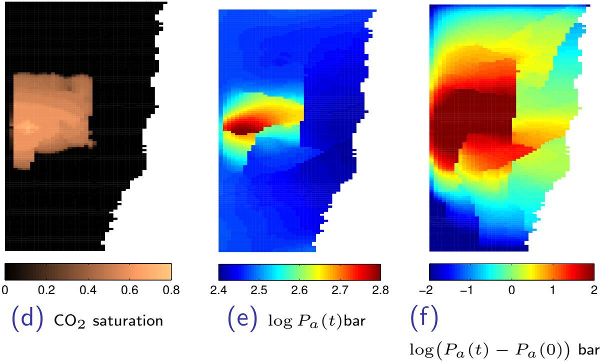
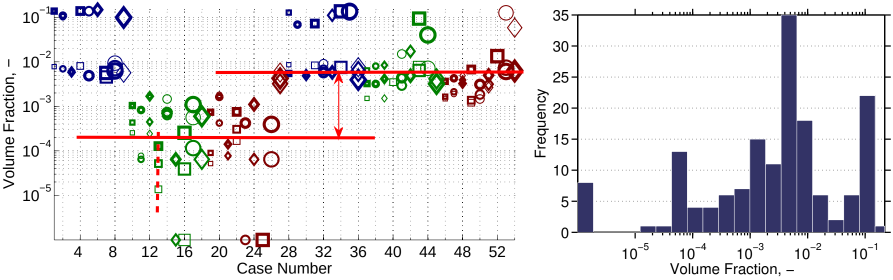


Figure : Top view of responses at the middle of the injection period (15 years) for the rate-constrained injection scenario.

Responses for pressure analysis

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

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_2 plume and keep the flow restricted to the geological layers in which the CO_2 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

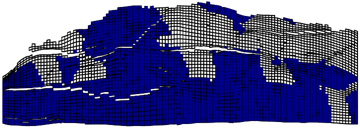
The goal of this study is

to demonstrate the application and feasibility of the arbitrary polynomial chaos expansion (aPC) for global sensitivity and probabilistic risk analysis of a typical CO_2 *injection scenario in realistic geological realizations.*

Paper III: Outline

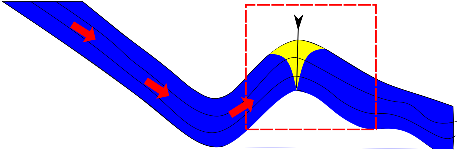
Steps in the study:

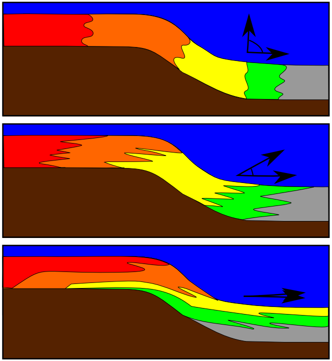
- Four geological parameters are selected for the study.
- Fixed injection rate scenario via a single well is defined.
- 15 full simulation runs are performed.
- Arbitrary polynomial chaos (aPC) is tuned to the run results.
- Sensitivity analysis is performed using the generated aPC.
- Probabilistic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



Geological parameters:

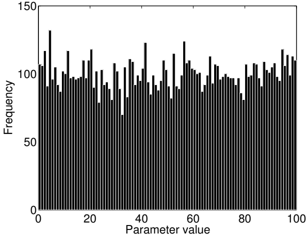
- Aggradation angle.
- Barriers coverage.
- Fault transimissibility.
- External aquifer support.



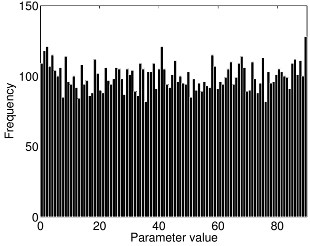


Paper III: Parameter Uncertainty

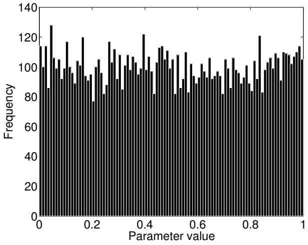
Barries



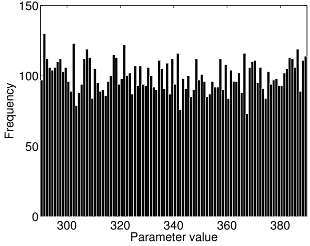
Aggradation



Faults



External Flux

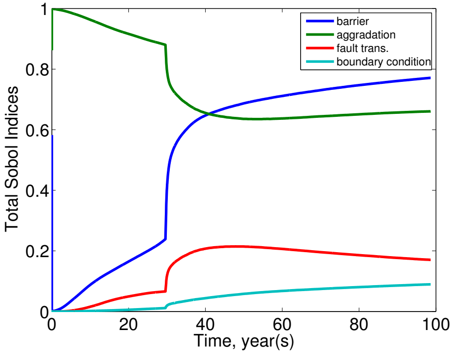


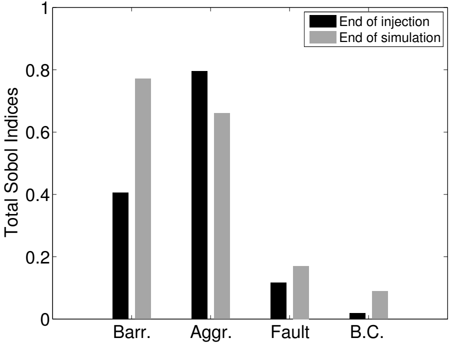
Paper III: Workflow

- *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.

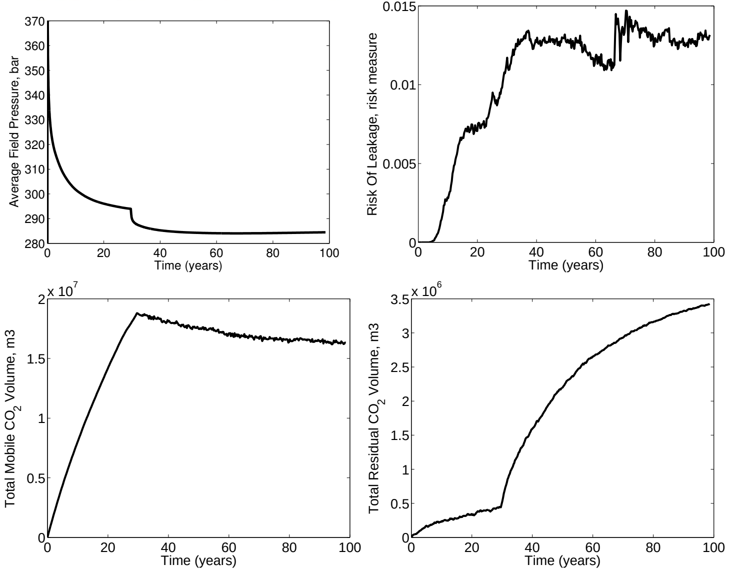
Paper III: Global Sensitivity Analysis

Average CO_2 Pressure, Sobol Indices

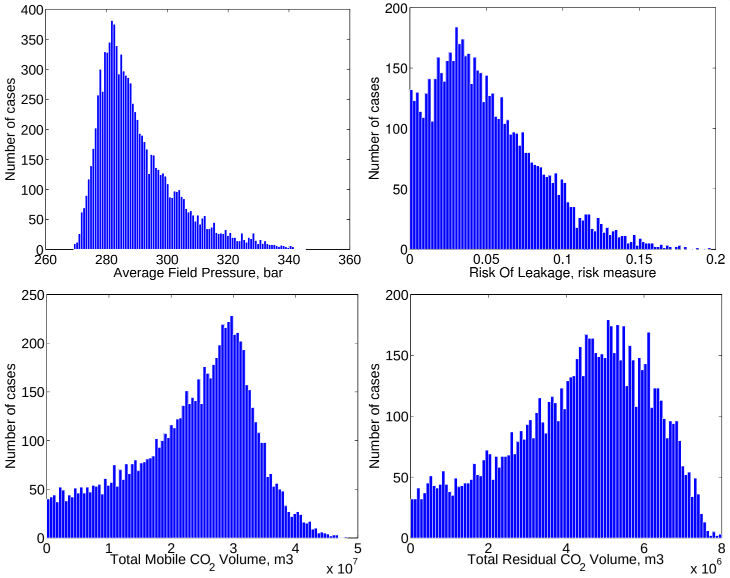




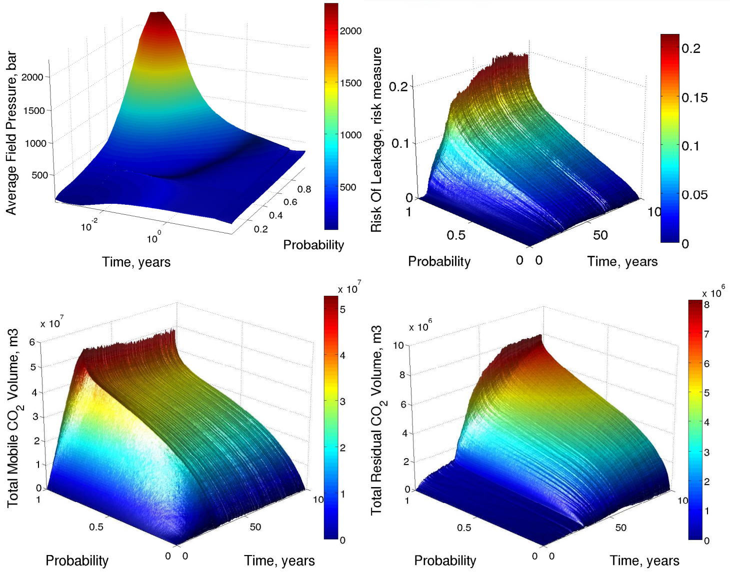
Paper III: Expectations



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 **aggradation 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_2 storage operations.
- Introduce a framework for extensive realistic sensitivity analysis and risk assessment of geological CO_2 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_2 storage. Ranges are extracted from.

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

Celia and Nordbotten, Geological Storage of CO_2 Modeling Approaches for Large-Scale Simulation. Wiley, 2011.

Temporal Scales

Temporal scales for CO_2 storage. Ranges are extracted from.

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

Celia and Nordbotten, Geological Storage of CO_2 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:

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

Orthogonality Of Basis

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

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

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

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

where δ is the Kronecker delta function and τ is the measure for input variable space.

Parameter Uncertainty

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

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

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

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

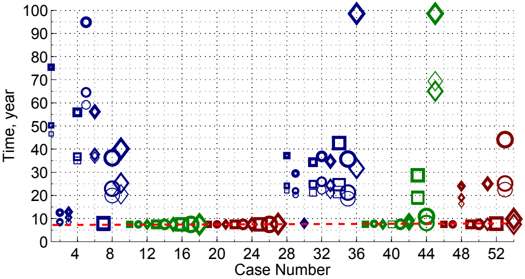
OLADYSHKIN, CLASS, HELMIG, AND NOWAK, concept for data-driven uncertainty quantification and its application to carbon dioxide storage in geological formations. Advances in Water Resources 34 (2011), 1508–1518, doi: 10.1016/j.advwatres.2011.08.005.

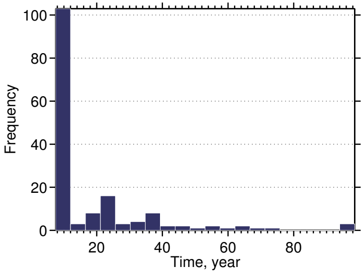
Paper II: Simulation Setup

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_2 saturation	0.2
K_{rCO_2}	CO_2 relative permeability	$(1 - S_{CO_2} - S_{rw})^2$
K_{rw}	Brine relative permeability	$(S_w - S_{rCO_2})^2$
ρ_{CO_2}	Supercritical CO_2 density at reference pressure	700.15 kg/m^3
ρ_w	Brine density at reference pressure	1033 kg/m^3
C_{rock}	Rock compressibility	0.3×10^{-6} 1/bar
C_{CO2}	CO_2 compressibility	0.375×10^{-4} 1/bar
C_{water}	Water compressibility	0.3×10^{-6} 1/bar
P_0	Reference pressure	400 bar
μ_{CO_2}	CO_2 viscosity	0.04 cP
μ_w	Brine viscosity	0.4 cP
q	Target injcetion rate	3600 m^3/day
P_{cr}	Critical well pressure	400 bar

Time to inject a quarter of the total specified CO_2 volume for all cases in the pressure-constrained scenario: Aggradation effect.



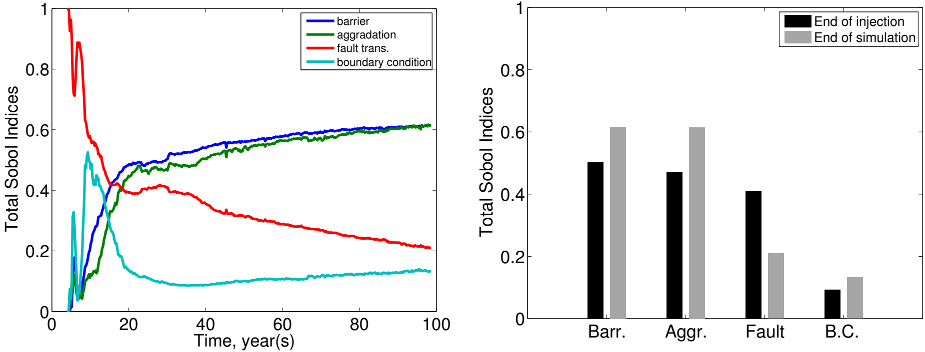


Paper III: Simulation Scenarios

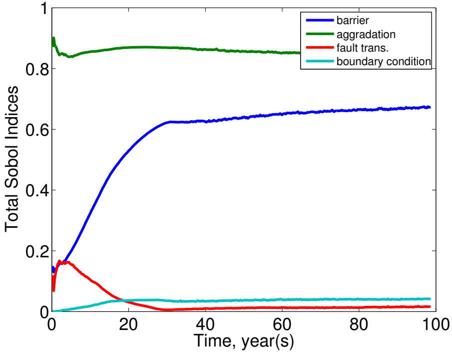
Similar to the initial study, 30 *years* of injection with fixed rate of $3650\ m^3/day$ via one well and 70 *years* of early migration are modeled.

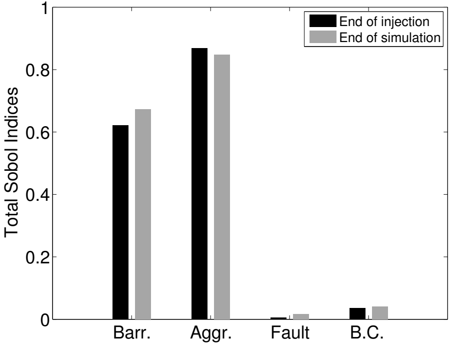
Parameter	Value	Unit
Number of active cells in the model	78720	-
Resolution X,Y,Z	40 $\times$ 120 $\times$ 20	-
Scale X,Y,Z	3000 $\times$ 9000 $\times$ 80	m
Injection rate	3650	m^3/day
Initial pressure	266.5	bar
Critical CO_2 and water saturations	0.2	-
CO_2 viscosity	0.04	cp
Water viscosity	0.4	cp
Rock compressibility	0.3e-6	1/bar

Leakage Risk, Sobol Indices



Total Mobile CO_2 Volume, Sobol Indices





Paper III: Global Sensitivity Analysis

Total Residual CO_2 Volume, Sobol Indices