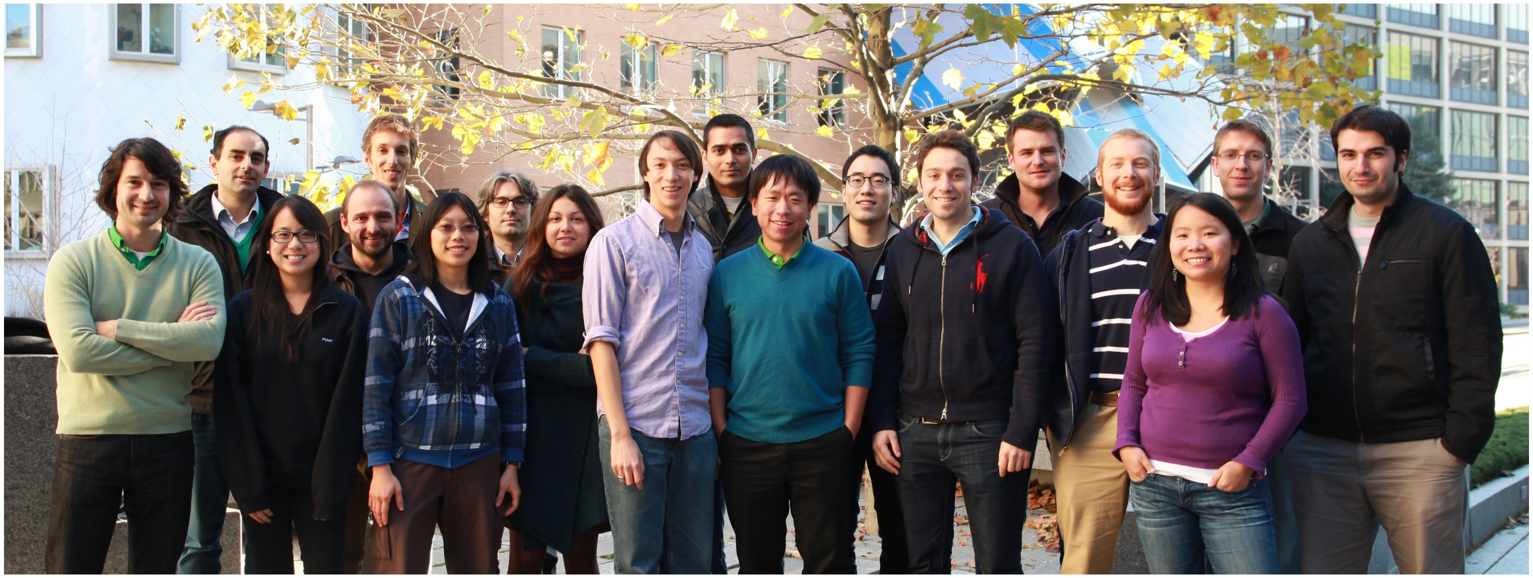


Juanes Research Group @ MIT

http://juanesgroup.mit.edu

We study the physics of multiphase flow in porous media.

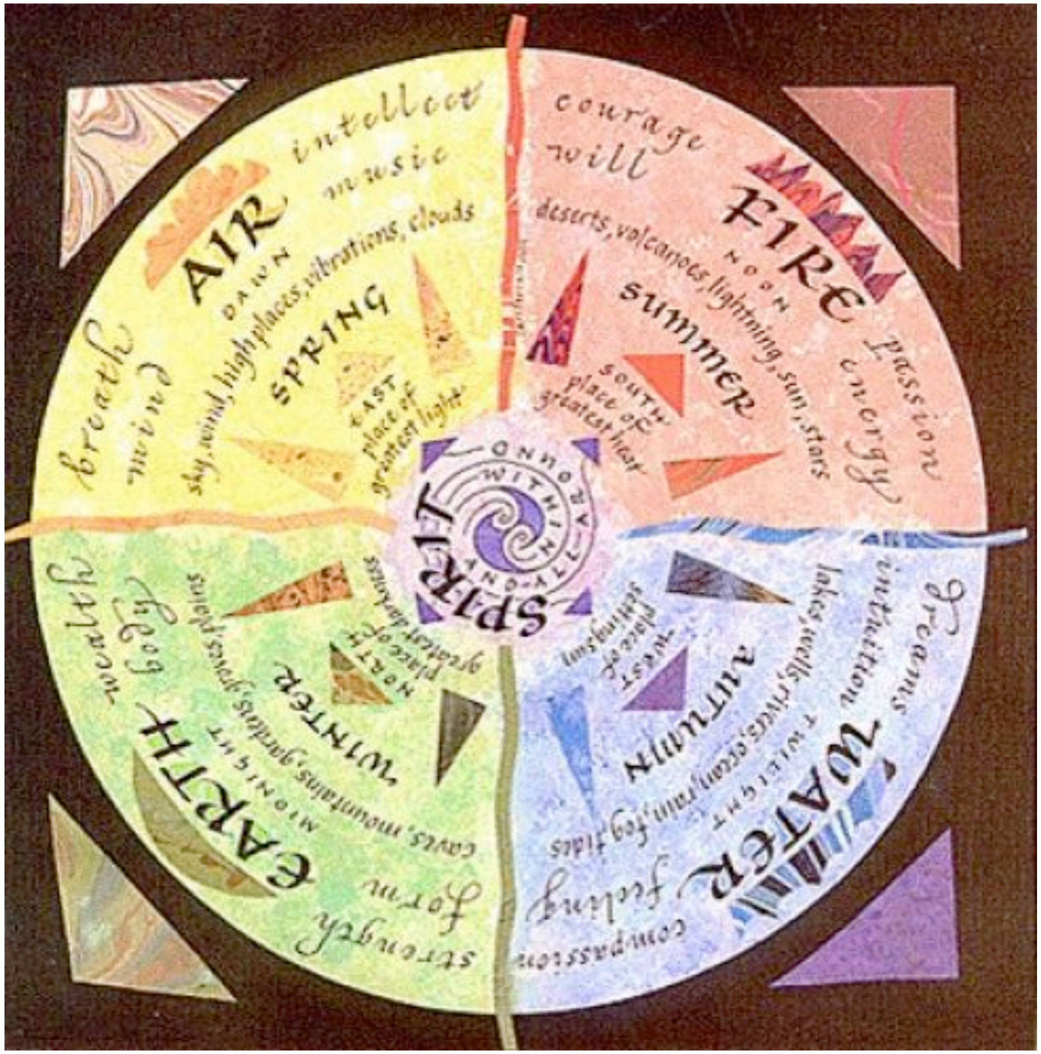
We apply our theoretical, computational and experimental research to geophysical problems in the area of energy and the environment

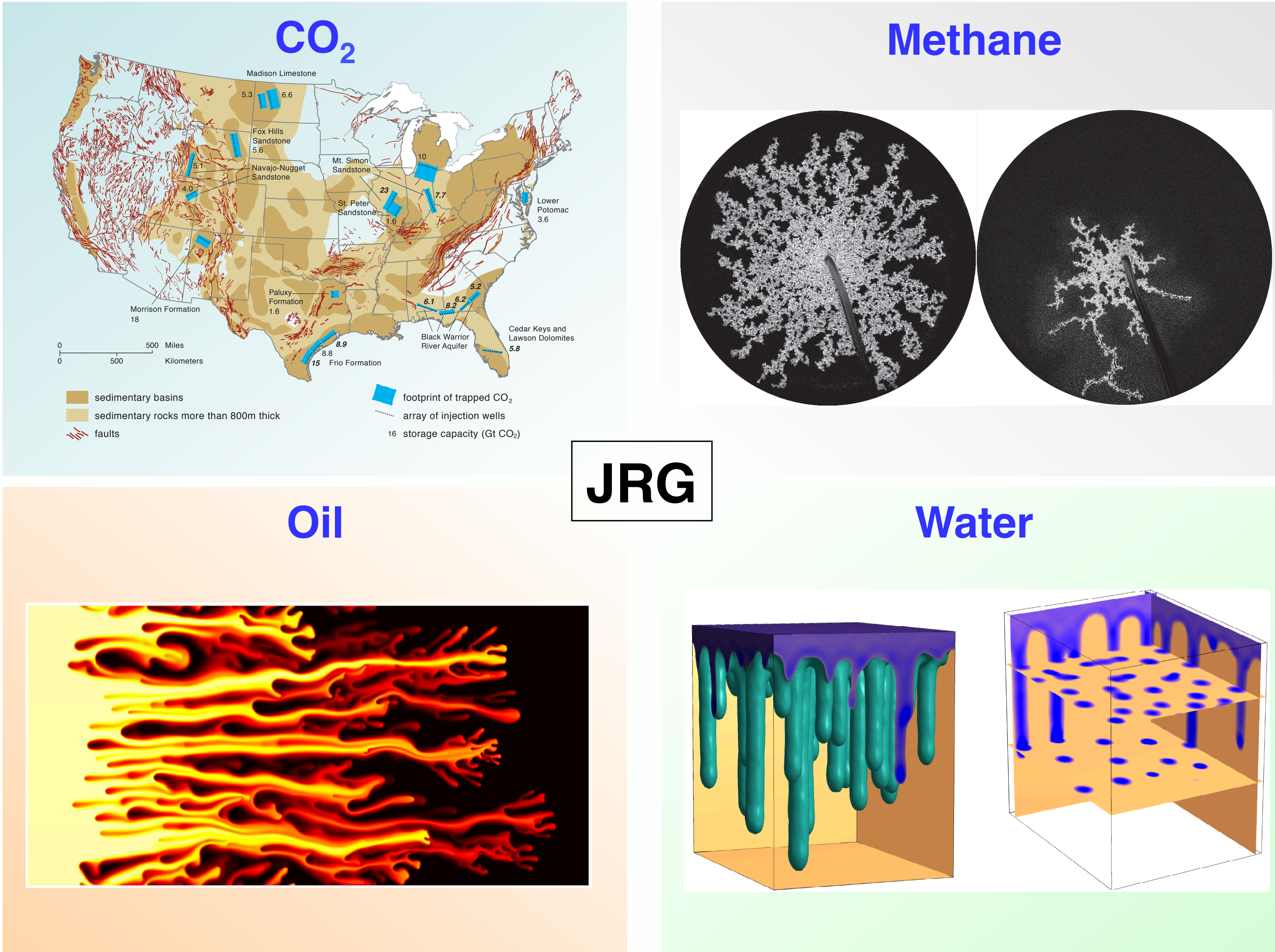
Why?

- Multiphase flow plays a fundamental role in critical Earth processes
  - Methane venting
  - CO_2 sequestration
  - Water infiltration

- *Modus Operandi:* first, understand the process at the small scale;
  then, apply to the large (continental) scale

The four classical elements



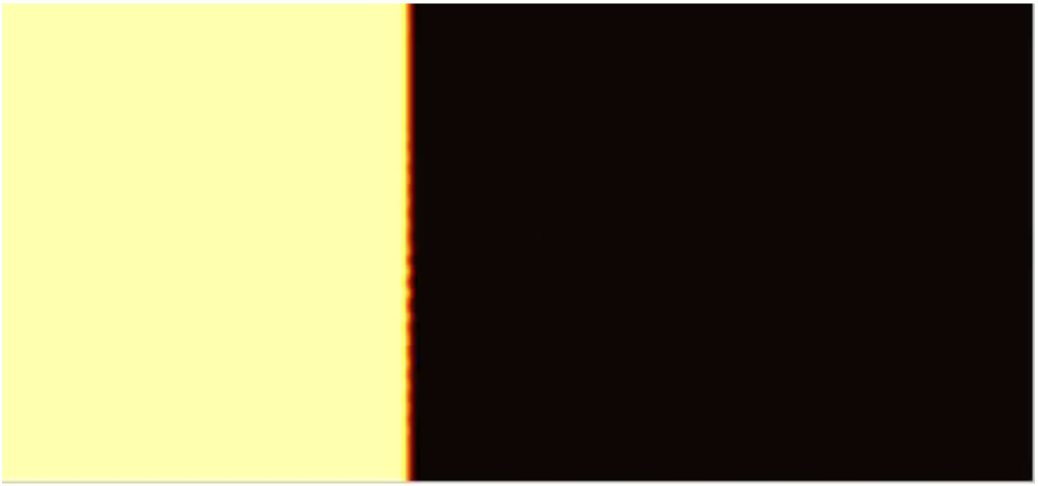


CO2
Madison Limestone
5.3
6.6
Fox Hills Sandstone 5.6
5.1
Navajo-Nugget Sandstone
4.0
Mt. Simon Sandstone
10
23
7.7
St. Peter Sandstone
1.6
Lower Potomac 3.6
Paluxy Formation 1.6
Morrison Formation 18
6.1
8.2
6.2
5.2
Black Warrior River Aquifer
Cedar Keys and Lawson Dolomites 5.8
8.9
8.8
15
Frio Formation
0 500 Miles
0 500 Kilometers
sedimentary basins
sedimentary rocks more than 800m thick
faults
footprint of trapped CO2
array of injection wells
16 storage capacity (Gt CO2)
Methane
JRG
Oil
Water

Mixing from viscous fingering

(Jha, Cueto-Felgueroso & Juanes, *Phys. Rev. Lett.* 2011)

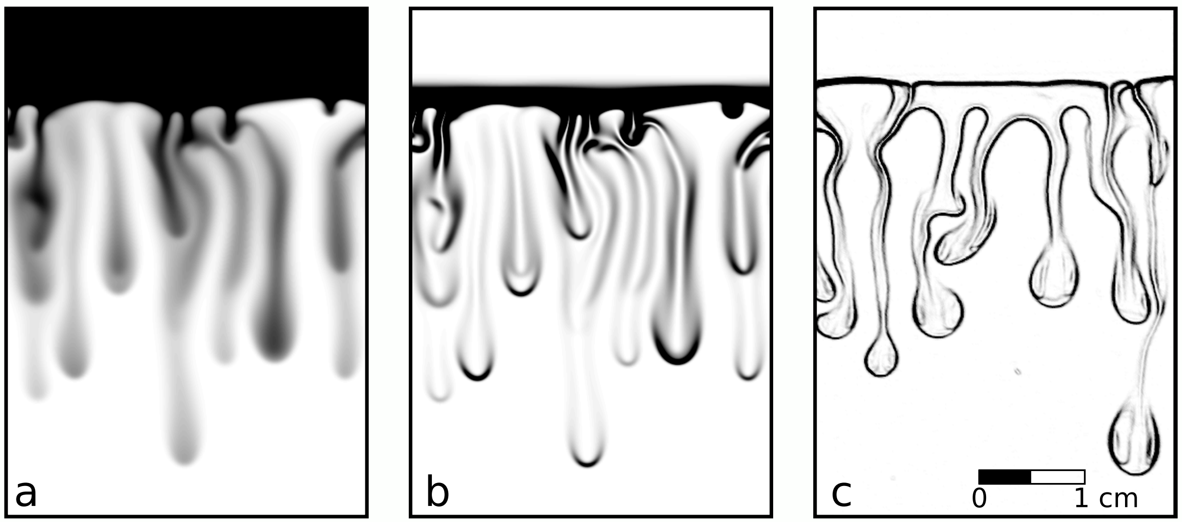
- Key question: does viscous fingering enhance or reduce mixing?
  - *Creation of interfacial area*: enhances mixing
  - *Channeling*: reduces mixing



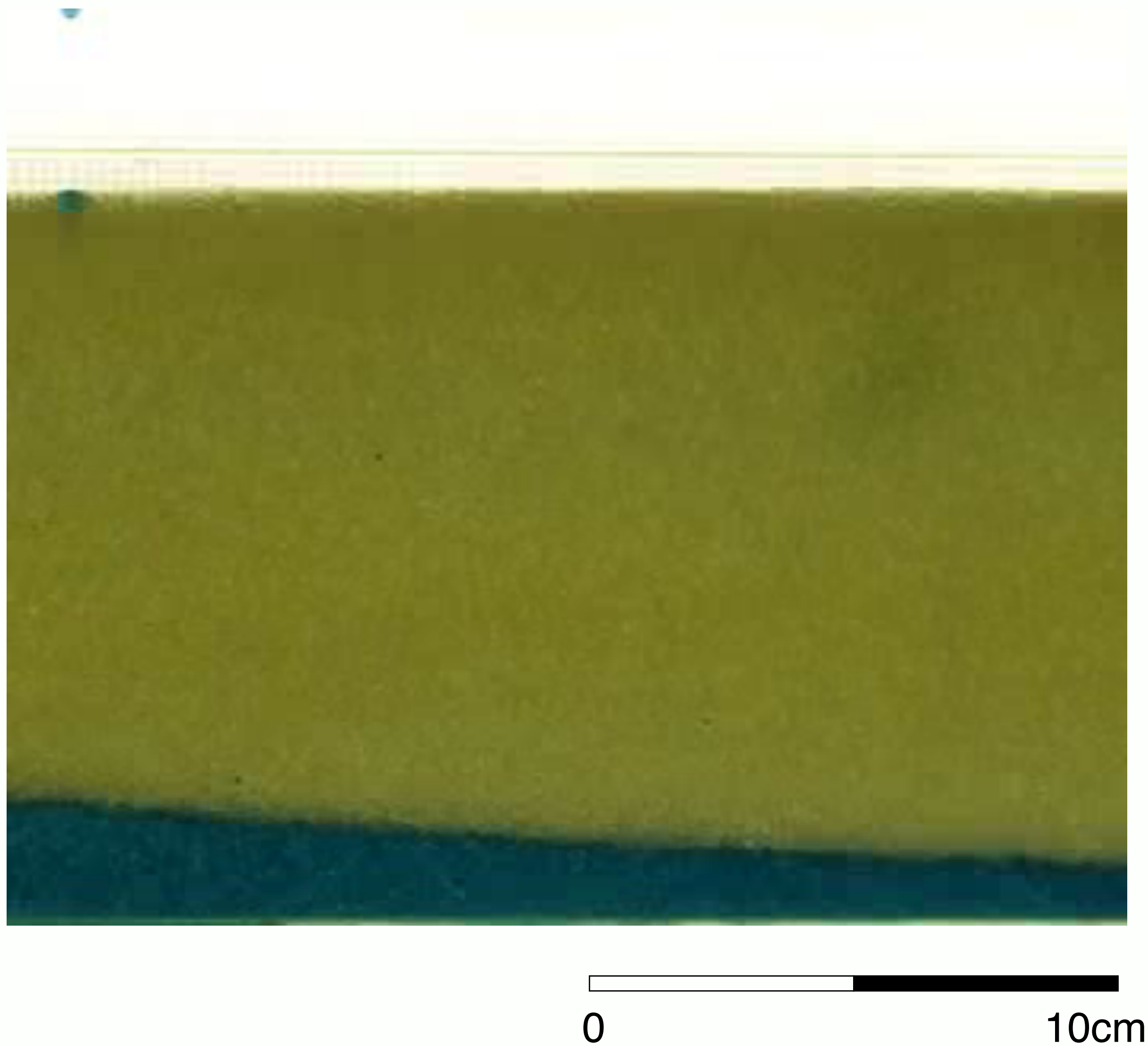
Mixing from gravitational instabilities

(Hidalgo, Fe, Cueto-Felgueroso & Juanes, *Phys. Rev. Lett.* 2012)

- Mixing is controlled by the scalar dissipation rate
- Mixing rate is constant and independent of Rayleigh number



Water infiltration in soil – lab experiments



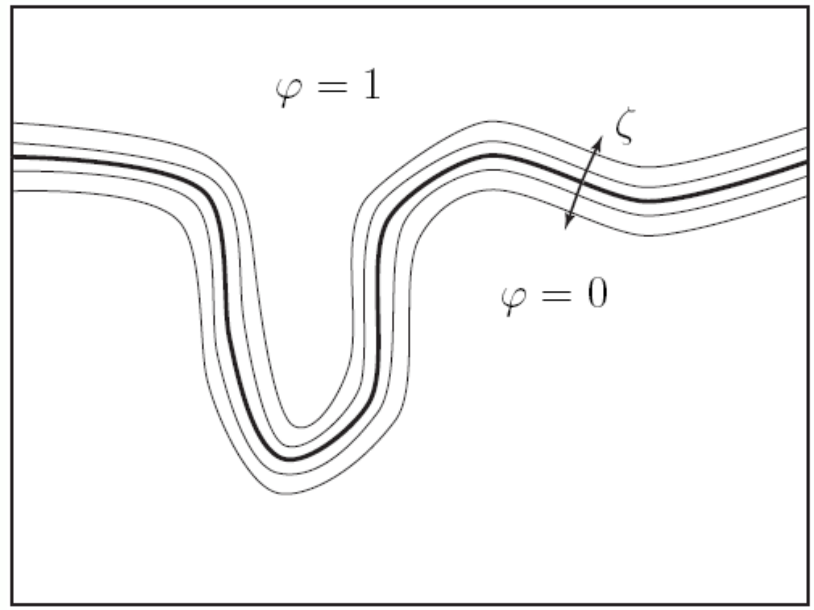
Phase-field modeling

Cueto-Felgueroso & Juanes (*Phys. Rev. Lett.* 2008)

- **Origin:** mathematical description of phase transitions (Cahn & Hilliard, 1958)
- **Two key ideas**

  - The energy depends on the presence of interfaces

  - Sharp interfaces are replaced by diffuse interfaces



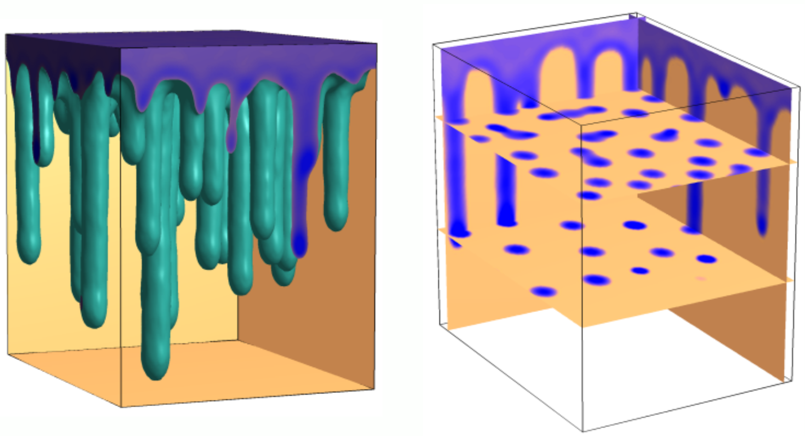
- **Order parameter φ**

  - labels "wet" and "dry" regions

$$\mathcal{E} = \mathcal{E}_{\text{bulk}} + \mathcal{E}_{\text{interf}} = f(\varphi) + \frac{\varepsilon}{2}|\nabla\varphi|^2$$

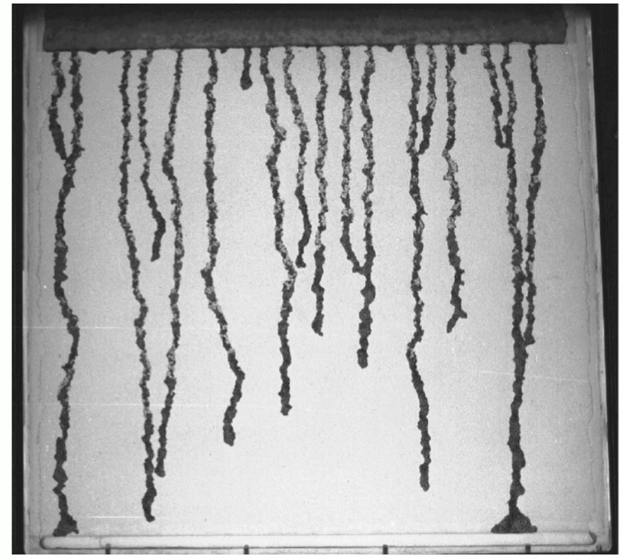
simulations

Cueto-Felgueroso & Juanes
(*Phys. Rev. Lett.* 2008)

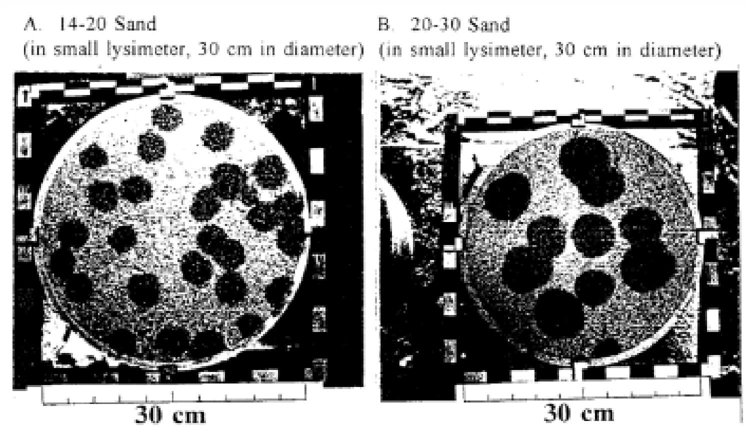


Gomez, Cueto-Felgueroso & Juanes
(*J. Comput. Phys.*, 2013)

experiments



Flekkøy et al. (*Phys. Rev. E* 2002)

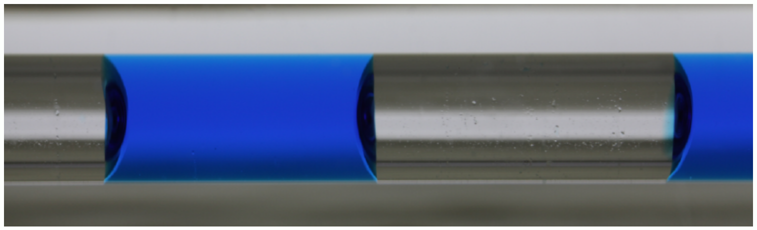


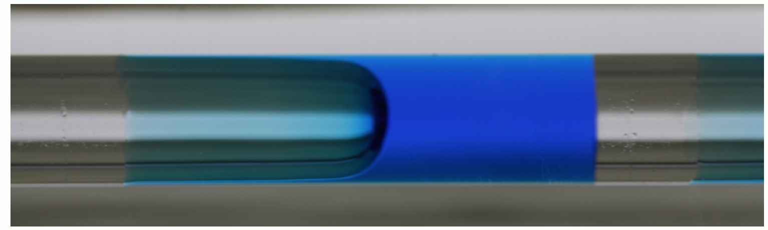
Yao (MS Thesis, 1993)

Phase-field model of partial wetting

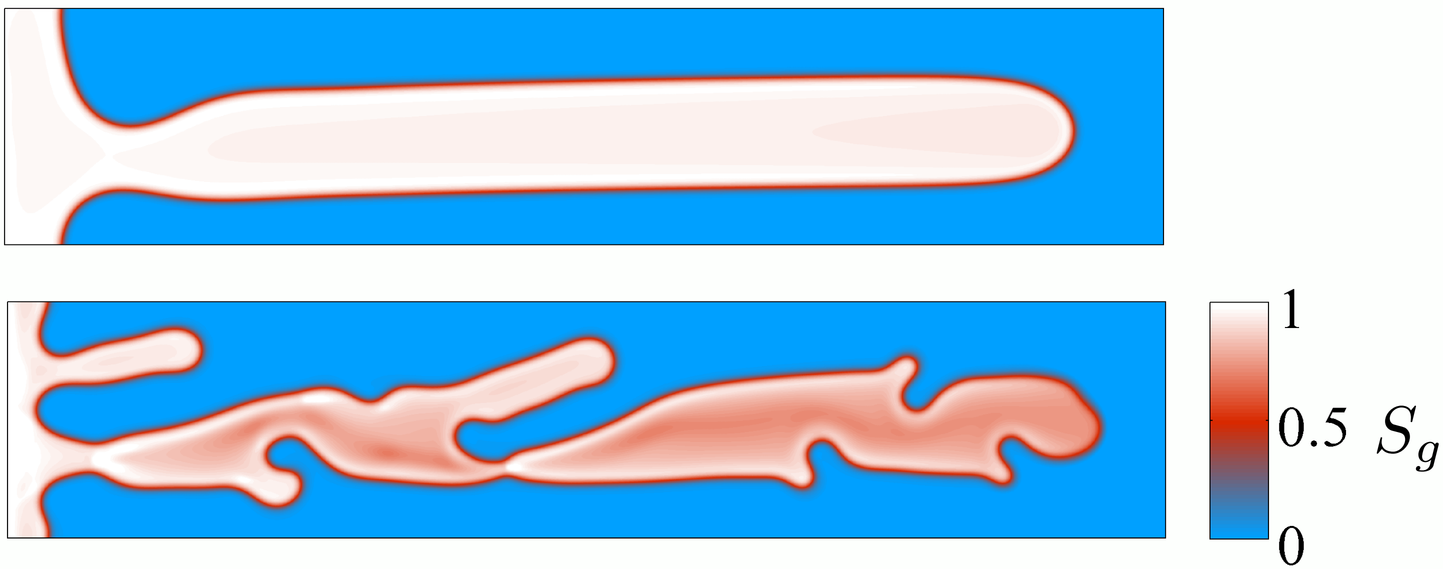
(Cueto-Felgueroso & Juanes, *Phys. Rev. Lett.* 2012)

- **Capillary tube**





- **Hele-Shaw cell**

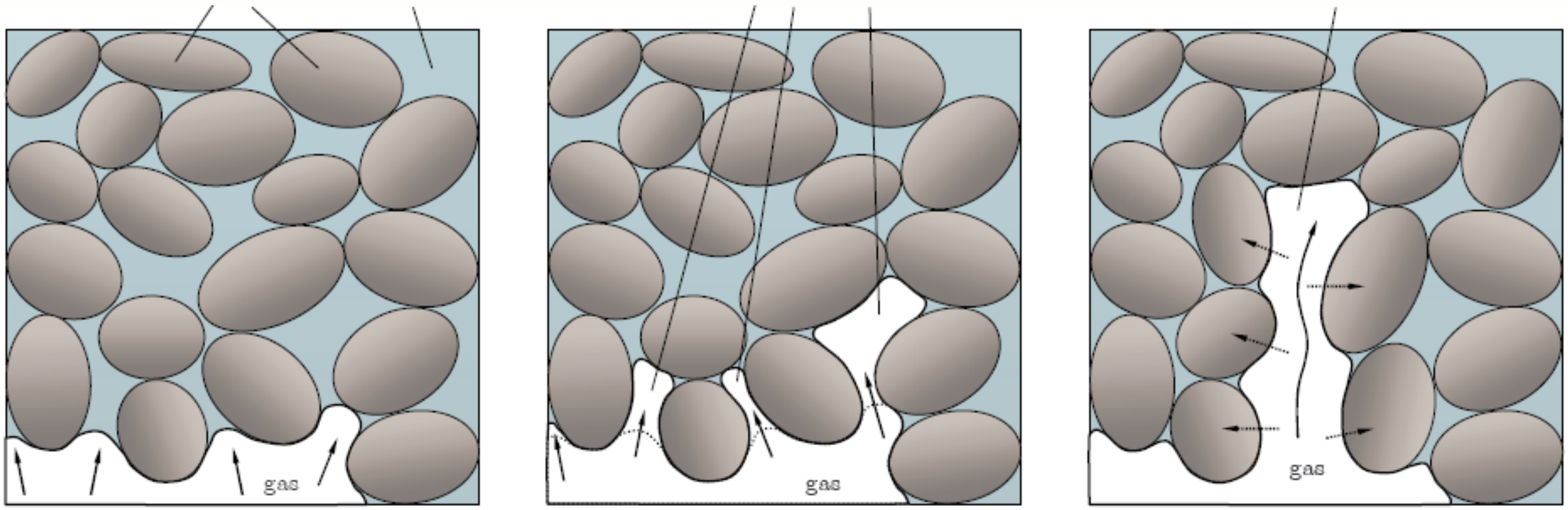


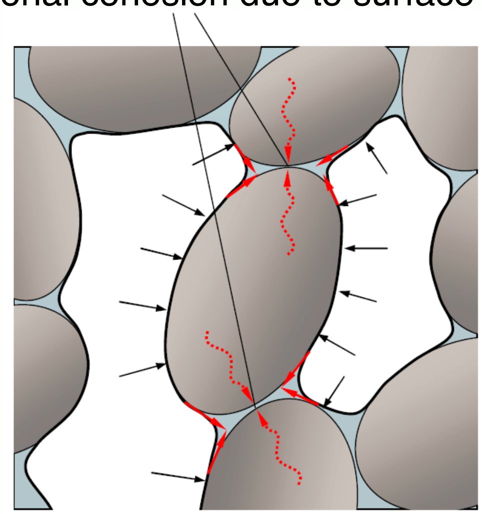
Methane venting from lake sediments and the continental shelf

- Contributes to atmospheric methane
- Powerful climate feedbacks

Courtesy of Katey Walter, UAF

Mode of methane invasion



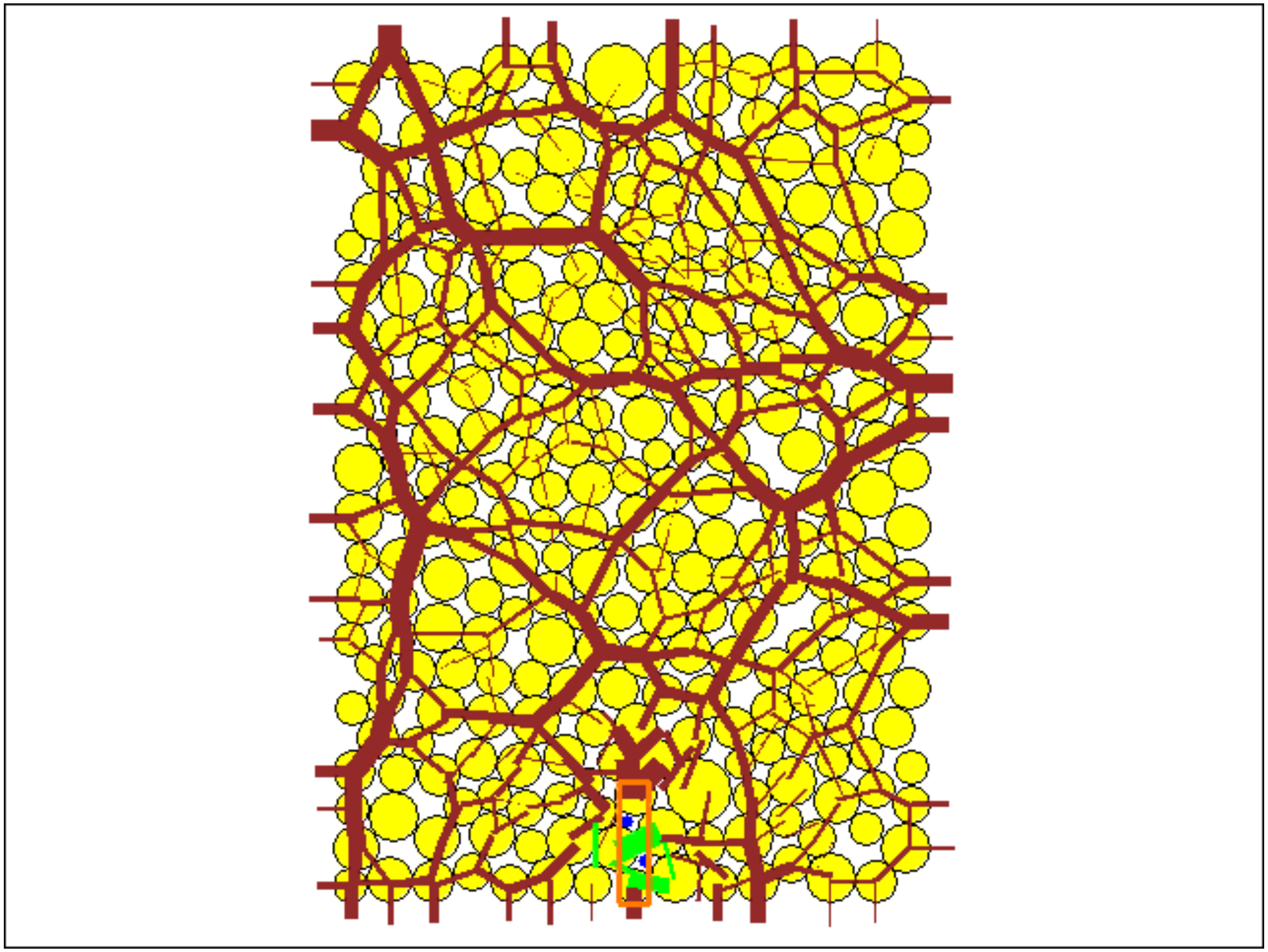


- ❑ **Essential physics: surface tension**

Capillary invasion vs. fracturing

Jain & Juanes (*J. Geophys. Res.* 2009)

- Capillary invasion in a rigid medium dominates for coarse-grain sediments
- Gas invades by fracturing in fine-grain sediments

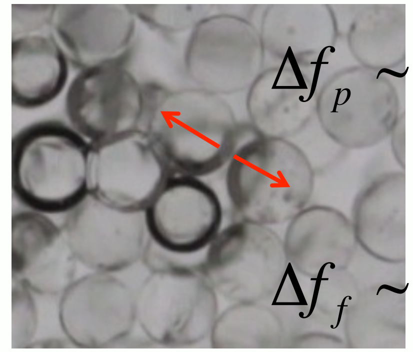


Transition from fingering to fracturing

Holtzman, Szulczewski & Juanes (*Phys. Rev. Lett.* 2012)

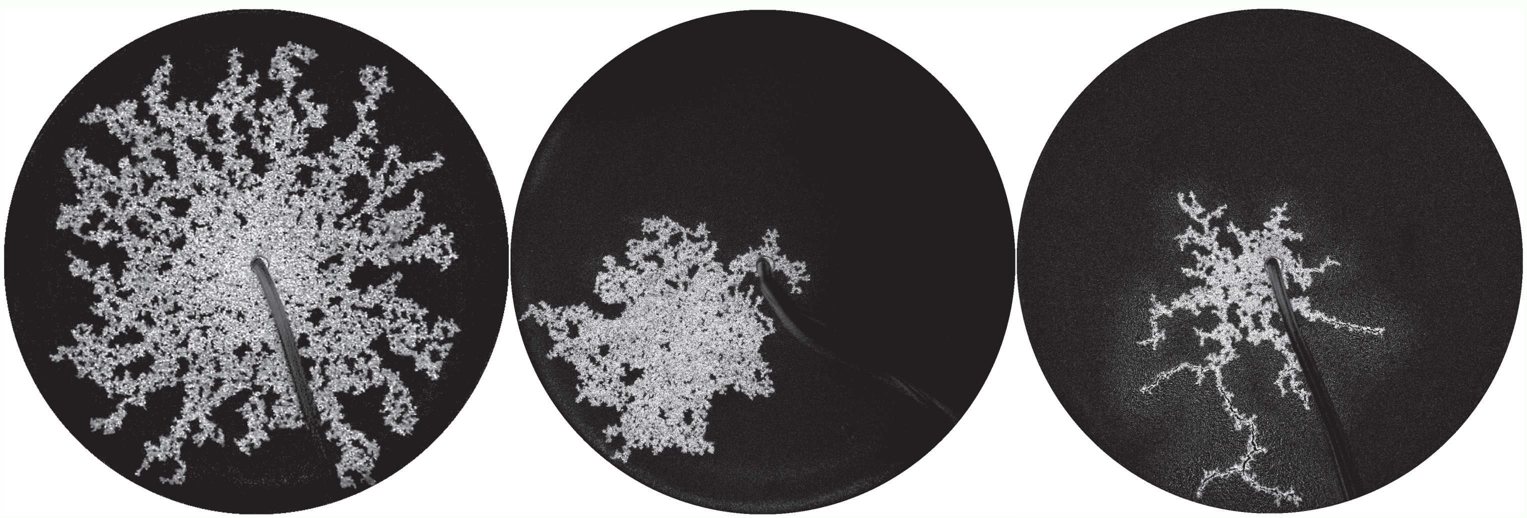
- Competition between <u>pressure</u> forces (from capillarity and viscosity) and <u>frictional</u> resistance between grains

- Crossover among gas invasion regimes



$$\Delta f_p \sim \gamma a + \eta v a$$

$$\Delta f_f \sim \mu w / (L/d)^2$$

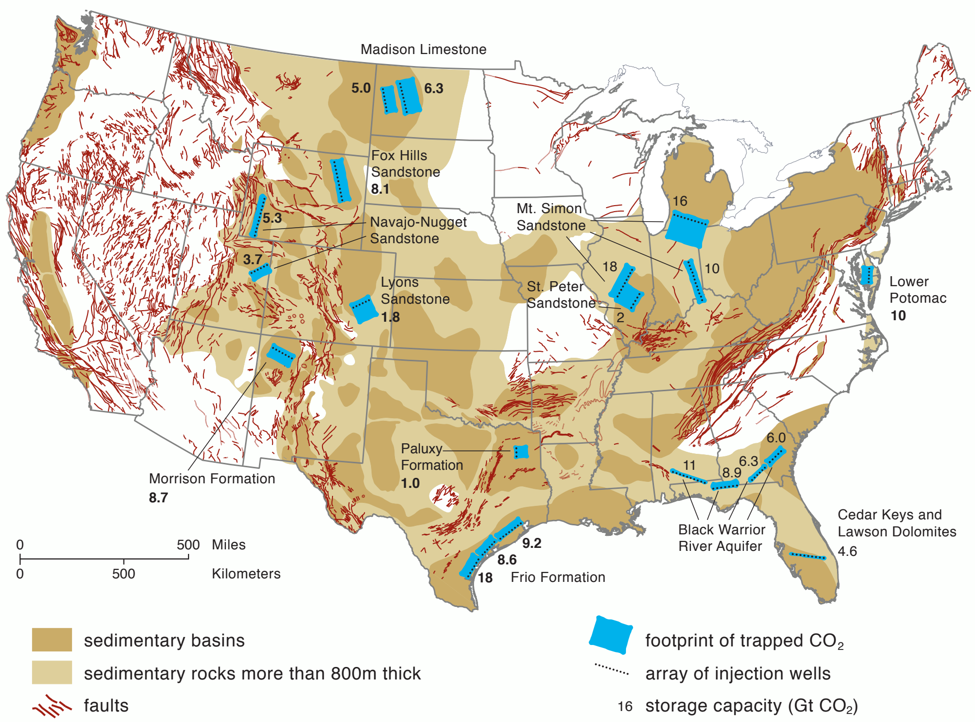


a. viscous fingering b. capillary fingering c. fracturing

The Lifetime of Carbon Capture and Storage as a Climate Change Mitigation Technology

Michael Szulczewski
Christopher MacMinn
Howard Herzog
Ruben Juanes

MIT
http://juanesgroup.mit.edu



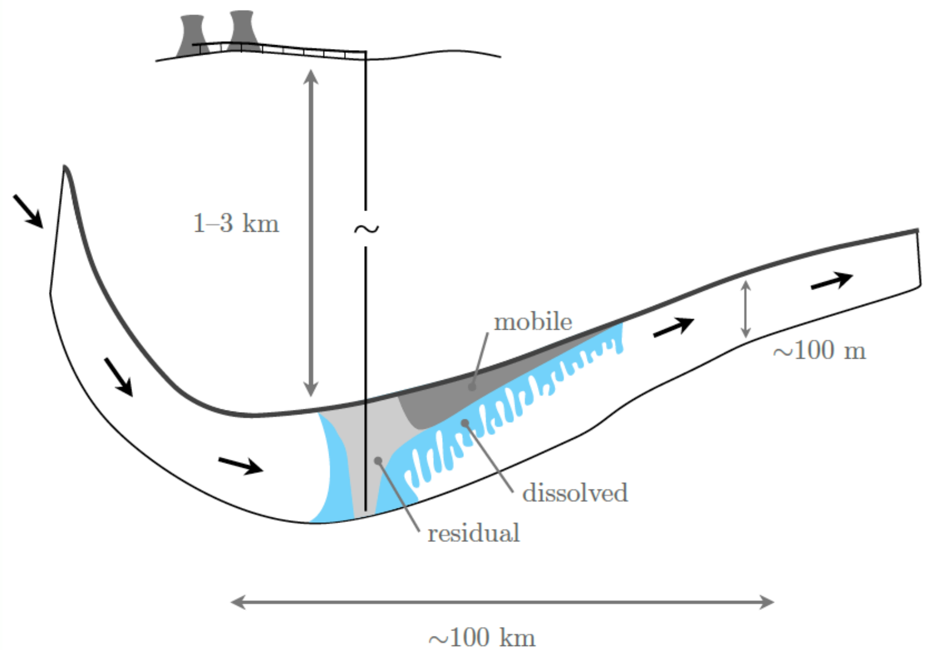
Fermilab Colloquium
January 30, 2013

How Big is the Problem, Really?

- In the United States alone …
  - Current emissions ~ 7 billion metric tons per year (7 $GtCO_2$/yr)
  - Coal-fired and gas-fired power plants ~ 35% ~ 2.4 $GtCO_2$/yr
- Take 1 GtCO2/yr ("1 unit") …
  - That's 1 billion tons per year, 10^{12} kg/yr
  - At a reservoir density ~ 500 kg/m^3, that's 2×10^9 m^3/yr
  - 1 m^3 = 6.25 bbl, 1 year = 365 days, gives 35 million barrels per day
- 1000 times the injection rate at Sleipner
  - ~ 1 Sleipner every two weeks for the next 50 years

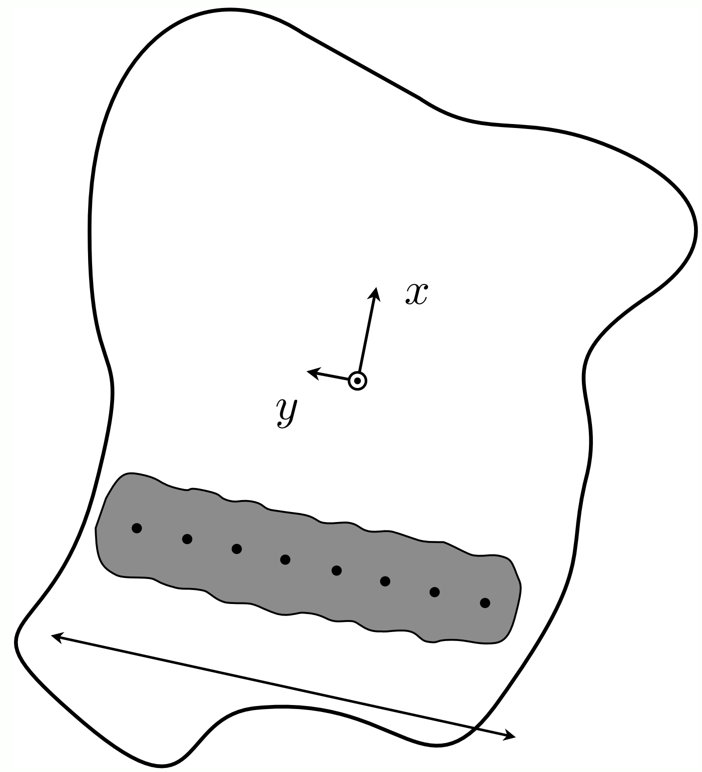
And that is to address just 15% of current emissions

Storage Must be Understood at the Scale of Geologic Basins



- Deep, thin
- Capped by impermeable layers
- Horizontal or weakly sloped $\vartheta \sim 1^\circ$
- Slow natural groundwater through-flow

$$U_n < 1\,\mathrm{m/year}$$



100 wells, 1 km spacing

Storage Capacity

- Storage capacity informs about the physical limitations of CCS, over which economic and regulatory limitations must be imposed
- We develop basin-scale capacity estimates based on fluid dynamics
- Two constraints:
  - The footprint of the migrating CO_2 plume must fit in the basin
  - The pressure induced by injection must not fracture the rock
- *Both constraints can be limiting in practice*, and which one applies is dependent on the aquifer and the injection period

Some controversy

- "underground carbon dioxide sequestration via bulk CO2 injection is not feasible at any cost." (Ehligh-Economides and Economides, *JPSE* 2010)
- "CCS can never work, US study says" (Canada Free Press on Ehlig-Economides and Economides, 2010)

Journal of Petroleum Science and Engineering 70 (2010) 123–130

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Sequestering carbon dioxide in a closed underground volume

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[a] *Department of Petroleum Engineering, Texas A&M University, College Station, Texas 77843, USA*

[b] *Department of Chemical Engineering, University of Houston, Houston, Texas 77204, USA*

Some controversy

- … and some rebuttals
  - "Open or closed? A discussion of the mistaken assumptions in the Economides pressure analysis of carbon sequestration" (Cavanagh, Haszeldine, and Blunt, *JPSE* 2010)
  - "The realities of storing carbon dioxide – A response to CO2 storage capacity issues raised by Ehlig-Economides & Economides" (Chadwick et al., *Nature Preceedings*, 2010)

Traditional Approach

The volumetric equation for CO_2 resource calculation in saline formations with consistent units assumed is as follows:

$$G_{CO2} = A_t \, h_g \, \phi_{tot} \, \rho \, E$$

Parameter	Units*	Description
G_{CO2}	M	Mass estimate of saline formation CO_2 resource.
A_t	L^2	Geographical area that defines the basin or region being assessed for CO_2 storage calculation.
h_g	L	Gross thickness of saline formations for which CO_2 storage is assessed within the basin or region defined by A.
ϕ_{tot}	L^3/L^3	Average porosity of entire saline formation over thickness h_g or total porosity of saline formations within each geologic unit's gross thickness divided by h_g.
ρ	M/L^3	Density of CO_2 evaluated at pressure and temperature that represents storage conditions anticipated for a specific geologic unit averaged over h_g.
E**	L^3/L^3	CO_2 storage efficiency factor that reflects a fraction of the total pore volume that is filled by CO_2.

* L is length; M is mass.
**For details on E, please refer to Appendix 4.

Source: USDOE Methodology for Development of Geologic Storage Estimates for Carbon Dioxide, 2008
See also: Bachu et al., *IJGHGC* 2007

Traditional Approach

- Splitting the sources of trapping capacity (Bachu et al., *IJGHGC* 2007)
  - Stratigraphic traps

    $$M_{\mathrm{CO2,strat}} = \rho_{\mathrm{CO2}} V_{\mathrm{trap}} \phi (1 - S_{wi}) C_c$$

  - Residual-gas traps

    $$M_{\mathrm{CO2,resid}} = \rho_{\mathrm{CO2}} V_{\mathrm{sweep}} \phi S_{gr}$$

  - Solubility traps

    $$M_{\mathrm{CO2,solub}} = V_{\mathrm{aquifer}} \phi \rho_w X_{\mathrm{CO2}} C_s$$

  - Mineral traps
    - Highly uncertain and time-dependent

Traditional Approach

- Splitting the sources of trapping capacity

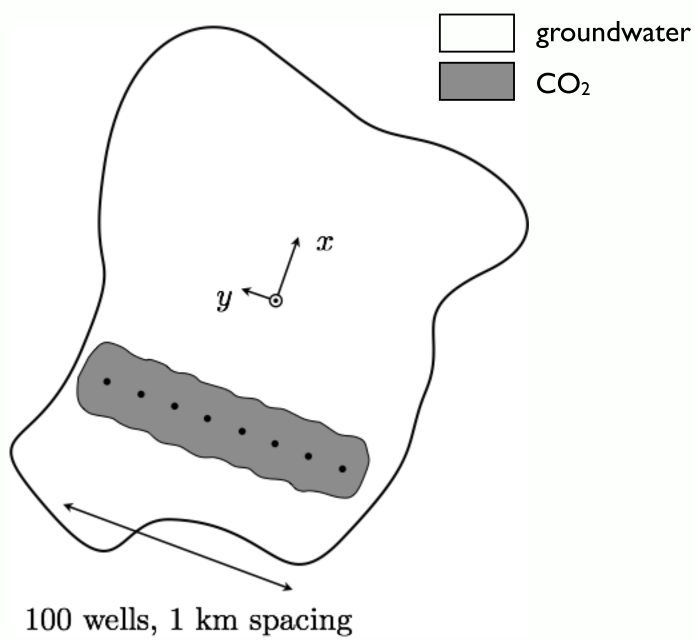
"estimation of the CO_2 storage capacity through residual-gas trapping can be achieved only in local- and site-scale assessments, but not in basin- and regional-scale assessments." (Bachu et al., *IJGHGC* 2007)

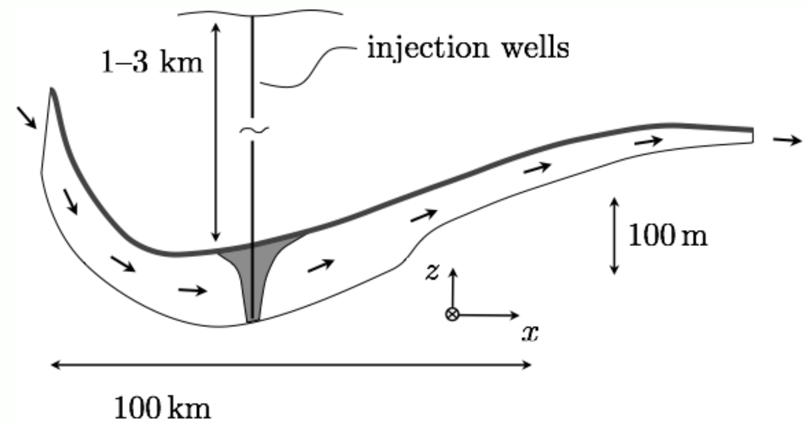
- Here we will show how to obtain basin-scale storage capacities that include residual and solubility trapping

Migration Model

The geologic setting of our migration model has two key features:

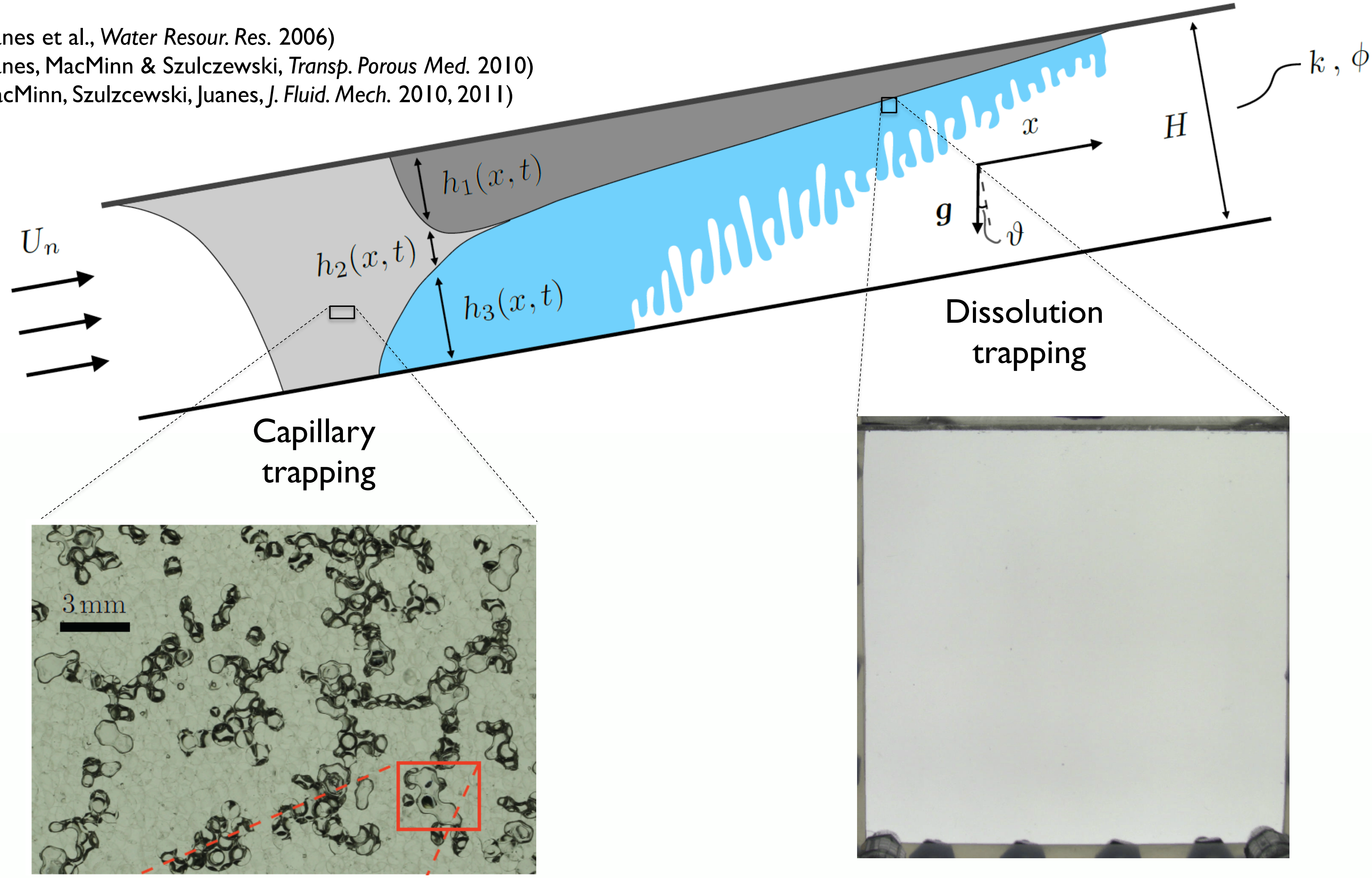
- basin scale
- line-drive array of wells



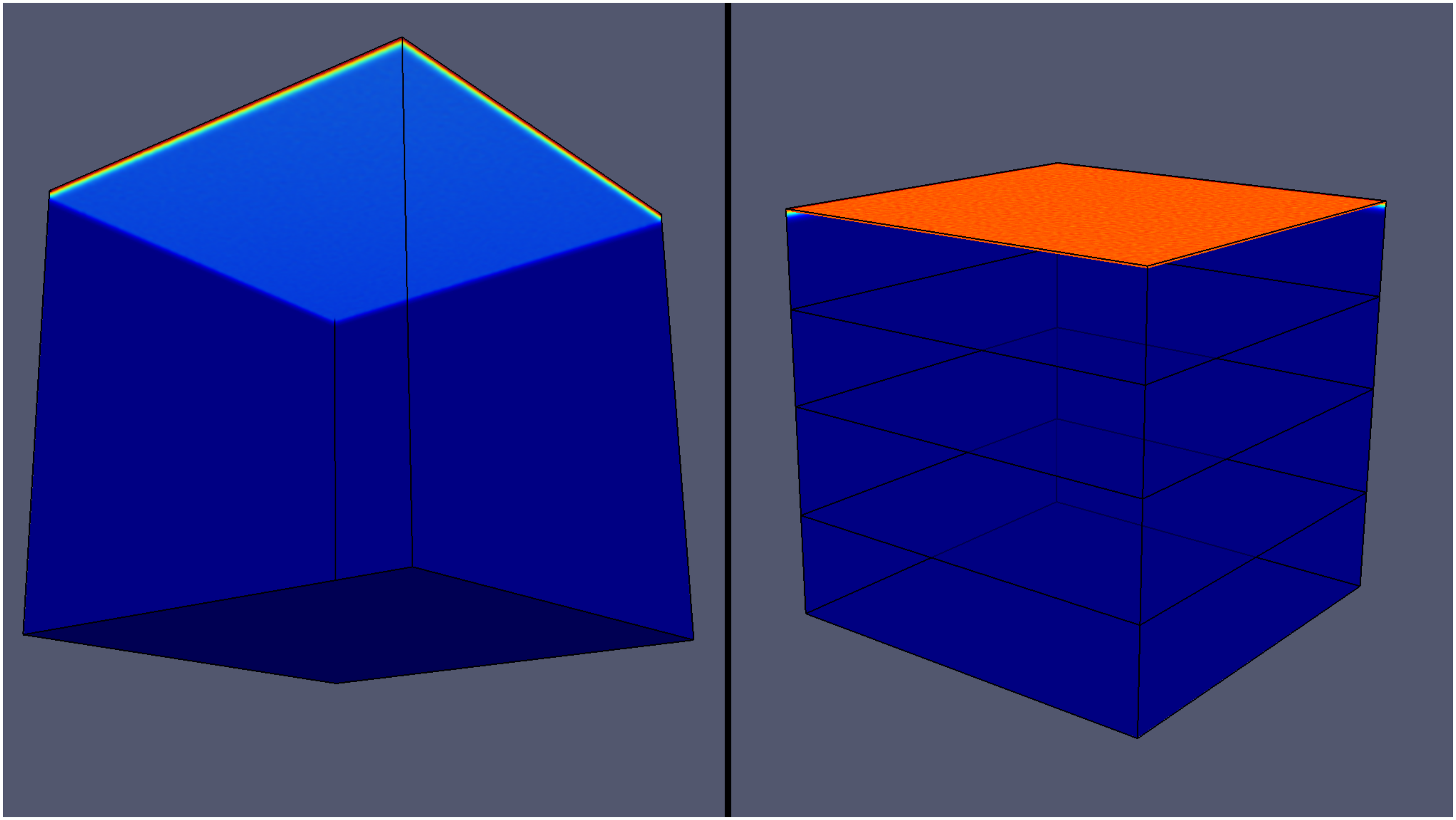


Trapping Mechanisms

(Juanes et al., *Water Resour. Res.* 2006)
(Juanes, MacMinn & Szulczewski, *Transp. Porous Med.* 2010)
(MacMinn, Szulczewski, Juanes, *J. Fluid. Mech.* 2010, 2011)



Dissolution by Convective Mixing



Modeling Approximations

Fluid

- sharp interfaces
- negligible capillary forces
- negligible fluid compressibility

Aquifer

- thin aspect ratio (vertical flow equilibrium / "Dupuit Approx.")
- homogeneous properties
- negligible rock compressibility

Bear
Elsevier 1972

Barenblatt *et al.*
Nedra 1972

Kochina *et al.*
Int. J. Eng. Sci. 1983

Hesse *et al.*
SPE 2006

Hesse *et al.*
JFM 2008

Nordbotten & Celia
JFM 2006

Juanes *et al.*
TiPM 2010

MacMinn *et al.*
JFM 2010, 2011

Migration without Dissolution

Advective Effects | Diffusive Effects

$$\widetilde{\mathcal{R}}\,\frac{\partial \eta}{\partial \tau} + N_f \frac{\partial f}{\partial \xi} + N_s \frac{\partial}{\partial \xi}\left[(1-f)\,\eta\right] - N_g \frac{\partial}{\partial \xi}\left[(1-f)\,\eta\,\frac{\partial \eta}{\partial \xi}\right] = 0$$

capillary trapping — g.w. flow — up-slope migration — spreading

$$\widetilde{\mathcal{R}} = \begin{cases} 1 & \partial\eta/\partial\tau > 0 \\ 1-\Gamma & \partial\eta/\partial\tau < 0 \end{cases}$$

$$f = \frac{\mathcal{M}\eta}{(\mathcal{M}-1)\eta + 1} \qquad \mathcal{M} = \frac{\lambda_g}{\lambda_w}$$

$$\Gamma = \frac{S_{gr}}{1-S_{wc}}$$

Scaling $\left\{ \quad \eta = \frac{h}{H} \qquad \tau = \frac{t}{T_c} \qquad \xi = \frac{x}{L_c} \right.$

$$N_f = 1 \qquad N_s = \frac{\Delta\rho g k \lambda_g}{U_n}\sin\vartheta$$

$$N_g = \frac{\Delta\rho g k \lambda_g}{U_n}\cos\vartheta\,\frac{(1-S_{wc})\phi H^2}{Q_i T_i/2}$$

$$T_c = \frac{Q_i T_i/2}{U_n H} \qquad L_c = \frac{Q_i T_i}{2H(1-S_{wc})\phi}$$

Migration without Dissolution

Advective Effects — Diffusive Effects

$$\widetilde{\mathcal{R}}\,\frac{\partial \eta}{\partial \tau} + N_f\,\frac{\partial f}{\partial \xi} + N_s\,\frac{\partial}{\partial \xi}\left[(1-f)\,\eta\right] - N_g\,\frac{\partial}{\partial \xi}\left[(1-f)\,\eta\,\frac{\partial \eta}{\partial \xi}\right] = 0$$

g.w. flow — up-slope migration — spreading

- Complete analytical solution
- Interaction between flow and slope

Juanes & MacMinn *SPE* 2008

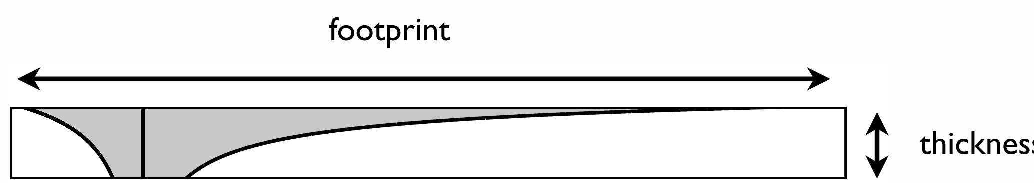
Juanes *et al.* *TiPM* 2010

MacMinn *et al.* *JFM* 2010

Efficiency Factor

- Macroscopic measure of storage efficiency
  - How much aquifer is “used” per unit CO_2 stored?

$$\varepsilon = \frac{\text{volume of } CO_2}{\text{volume of aquifer}} = \frac{2}{\xi_T}$$



Bachu *et al.*
Int. J. GHGC 2007

★ How does this depend on $\mathcal{M}$, Γ , N_s/N_f ?

Efficiency Factor

Transp Porous Med (2010) 82:19–30
DOI 10.1007/s11242-009-9420-3

The Footprint of the CO_2 Plume during Carbon Dioxide Storage in Saline Aquifers: Storage Efficiency for Capillary Trapping at the Basin Scale

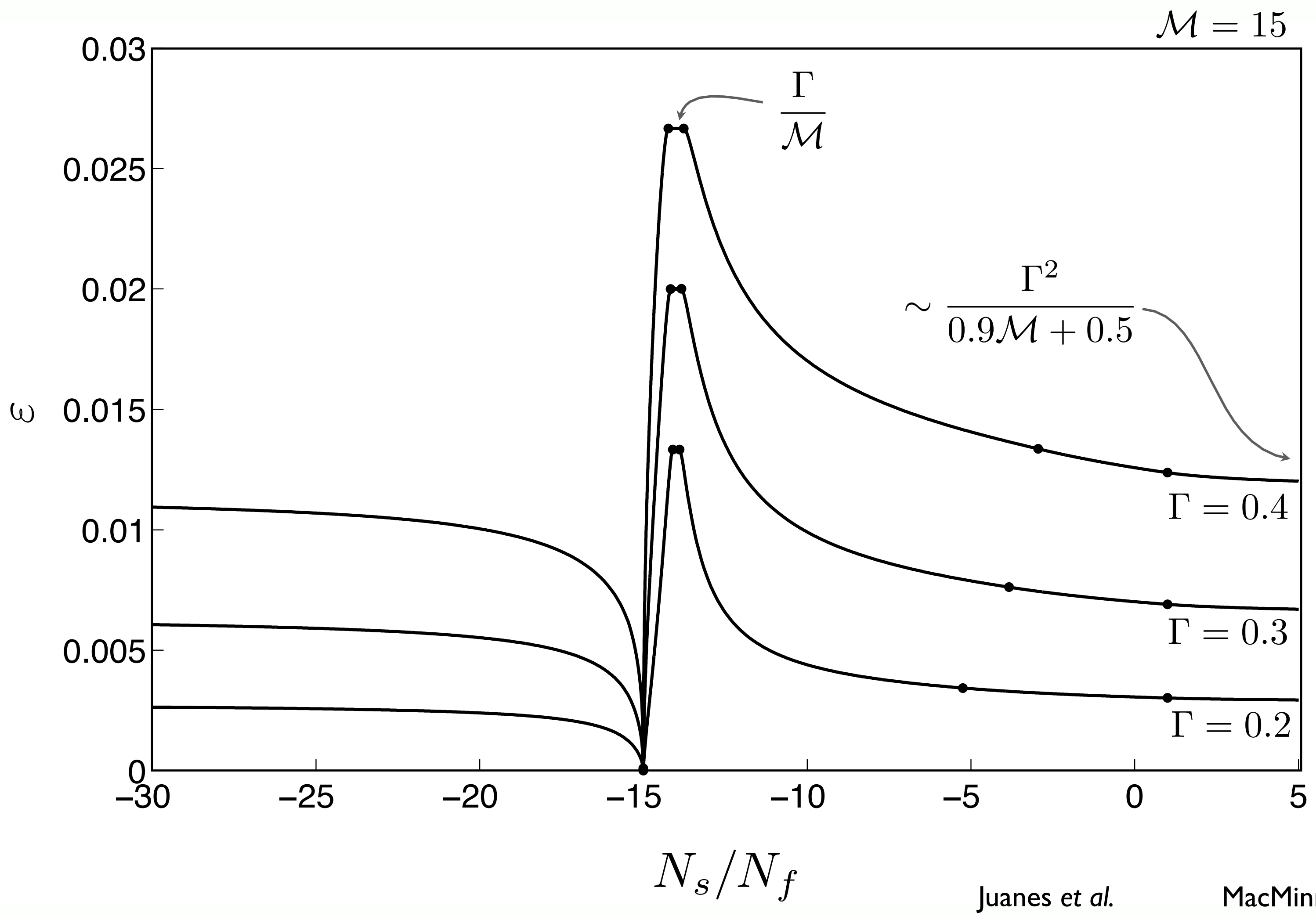
Ruben Juanes · Christopher W. MacMinn · Michael L. Szulczewski

J. Fluid Mech. (2010), *vol.* 662, *pp.* 329–351.
doi:10.1017/S0022112010003319

CO_2 migration in saline aquifers. Part 1. Capillary trapping under slope and groundwater flow

C. W. MACMINN[1], M. L. SZULCZEWSKI[2] AND R. JUANES[2]†

Storage Efficiency



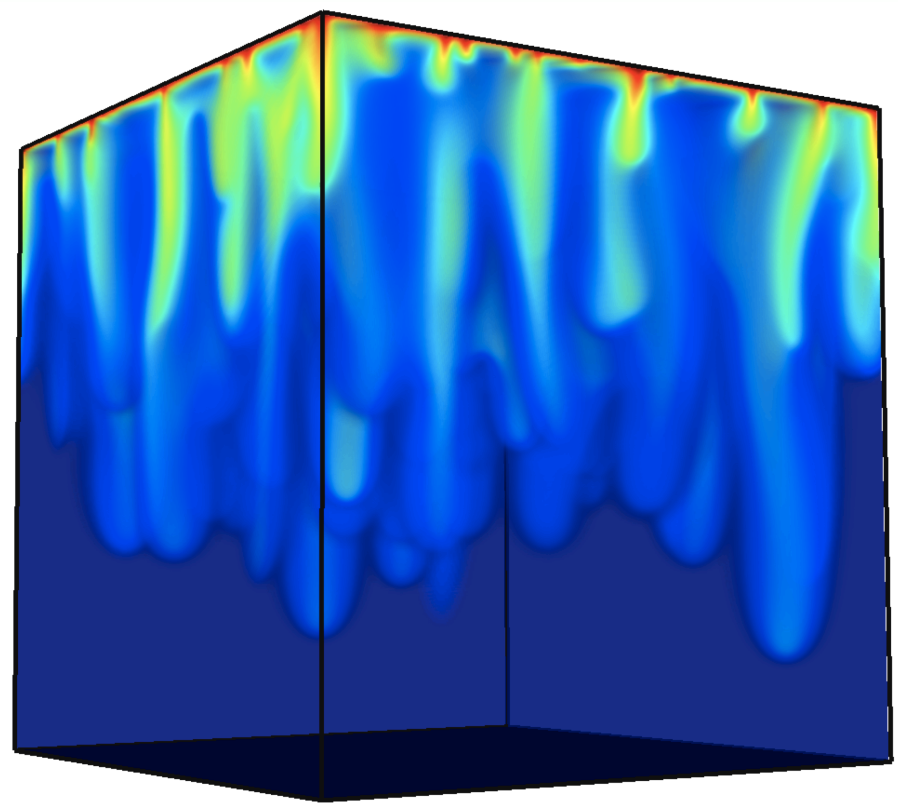
Juanes *et al.*
TiPM 2010

MacMinn *et al.*
JFM 2010

Dissolution by Convective Mixing

Convective mixing:

- CO_2 dissolves into ambient brine
- Density of brine increases with CO_2 content
- Boundary layer is unstable
- Constant average mass flux



Elder *JFM* 1968	Wooding *et al.* *WRR* 1997	Weir *et al.* *TiPM* 1996
Ennis-King *et al.* *Phys. Fluids* 2005	Riaz *et al.* *JFM* 2006	Pau *et al.* *AWR* 2010
Backhaus *et al.* *PRL* 2011	Neufeld *et al.* *GRL* 2010	Hidalgo *et al.* *PRL* 2012

Migration with Dissolution

Advective Effects — Diffusive Effects — Sink

$$\widetilde{\mathcal{R}}\frac{\partial \eta}{\partial \tau} + \boxed{N_f \frac{\partial f}{\partial \xi} + N_s \frac{\partial}{\partial \xi}\left[(1-f)\,\eta\right]} - \boxed{N_g \frac{\partial}{\partial \xi}\left[(1-f)\,\eta \frac{\partial \eta}{\partial \xi}\right]} = \boxed{-\widetilde{\mathcal{R}} N_d}$$

capillary trapping — g.w. flow — up-slope migration — buoyant spreading — dissolution

Essential features:

- CO_2 dissolves from the plume at a constant rate
- Dissolution does not drive residual trapping
- Dissolution stops when the water column saturates

Migration with Dissolution

Interplay between dissolution, saturation, and migration: two limiting cases

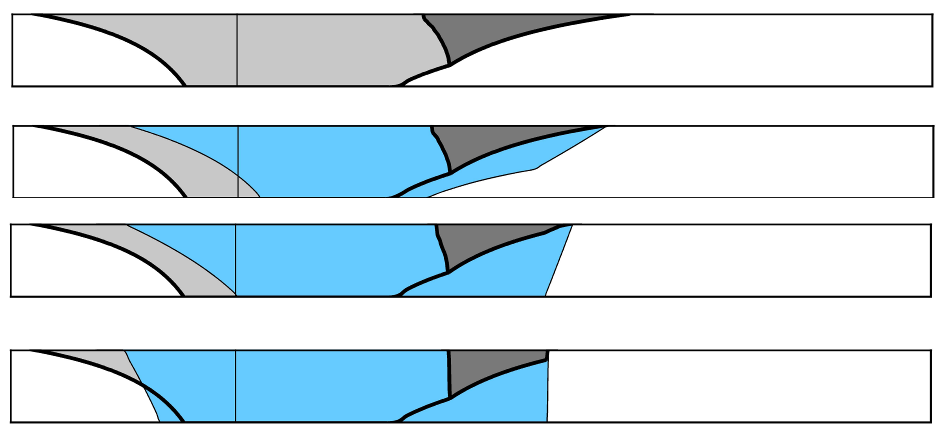
- **Slow saturation**: dissolution not limited by the amount of water beneath the plume
- **Instantaneous saturation**: only leading edge dissolves; water elsewhere saturated

$N_d = 0$

$N_d = 0.04$

$N_d = 0.1$

$N_d = 4$



Analytical Solutions with Dissolution

We can obtain *semi-analytical solutions* to the migration model in the two limits:

- *Slow saturation limit:* plume and curtain of saturated water do not interact
- *Instantaneous saturation limit:* water beneath the plume is completely saturated

J. Fluid Mech. (2011), *vol.* 688, *pp.* 321–351.
doi:10.1017/jfm.2011.379

CO_2 migration in saline aquifers. Part 2. Capillary and solubility trapping

C. W. MacMinn[1], M. L. Szulczewski[2] and R. Juanes[2]†

Experiments of Dissolving Gravity Currents

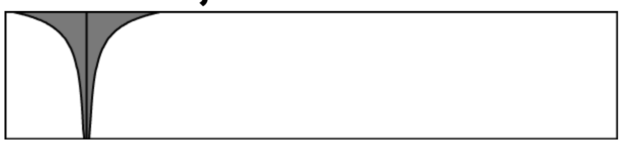
Convective mixing stops the plume

Migration Storage Capacity

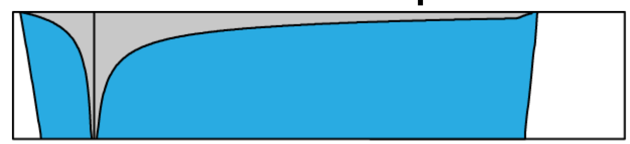
We estimate aquifer capacity by using the model in reverse

<u>Forward</u>

Set injection volume

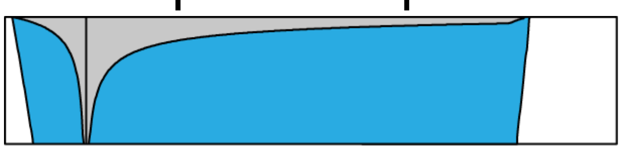


Calculate footprint

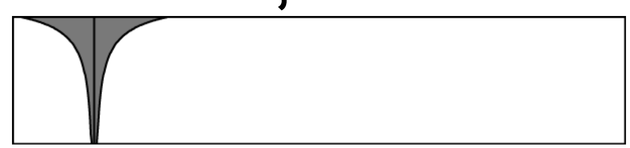


<u>Reverse</u>

Set footprint to aquifer size



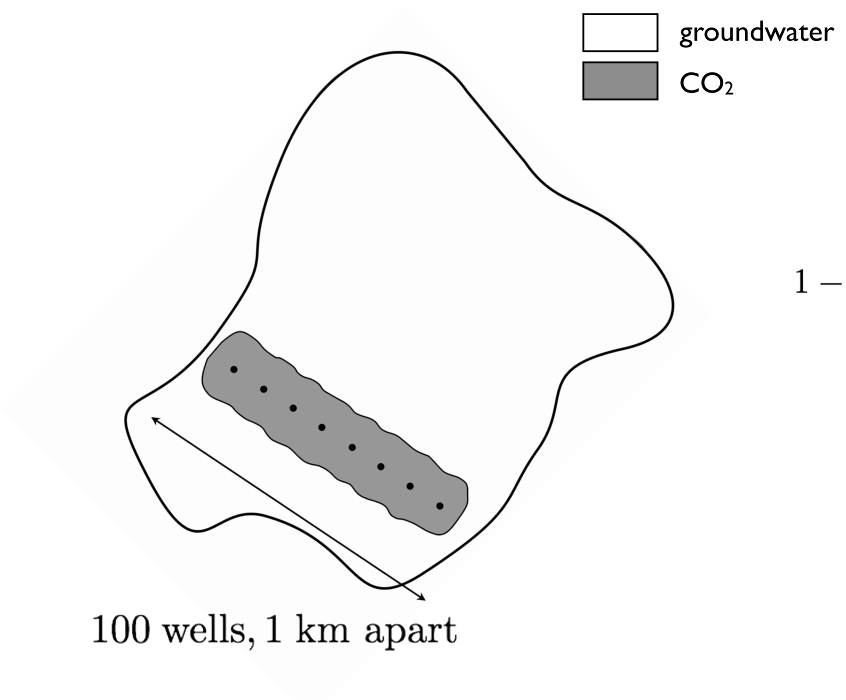
Calculate injection volume

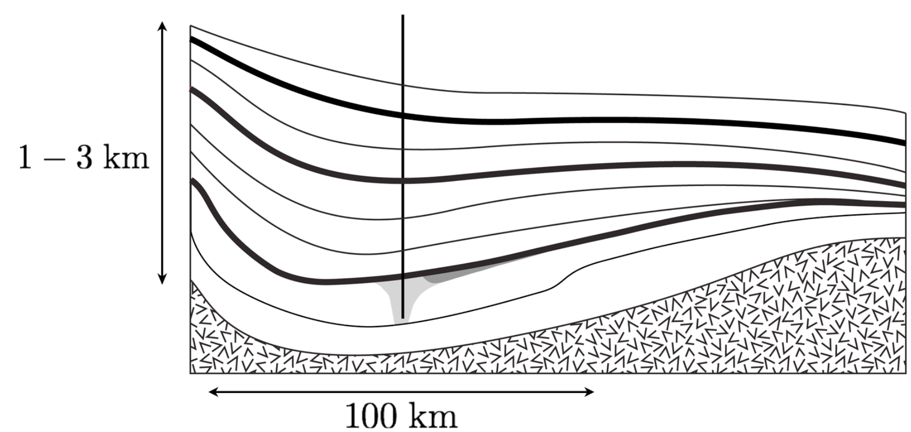


Pressure Model

The geologic setting of our pressure model has three key features:

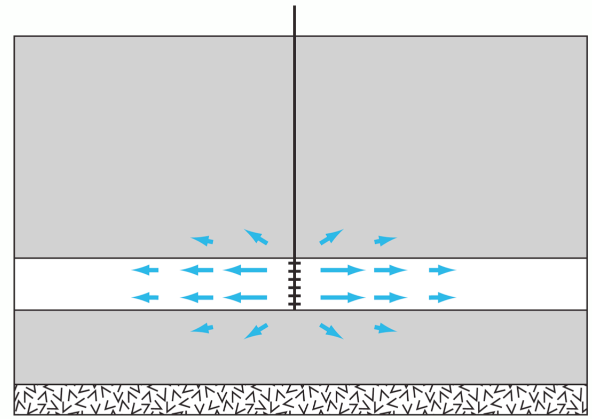
- basin scale
- line-drive array of wells
- multiple layers



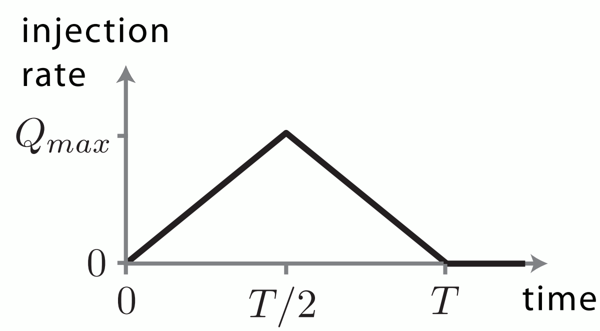


Model Features

- Lateral pressure dissipation
  - no-flow at faults and pinchouts
  - constant pressure at outcrops

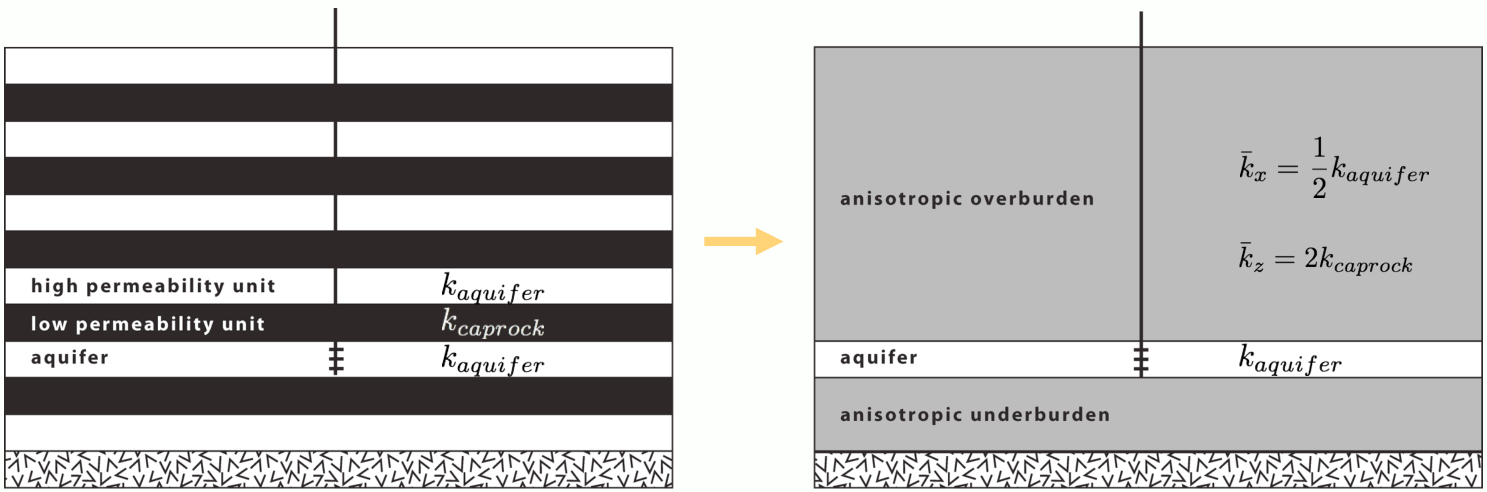


- Vertical pressure dissipation
  - major contributor to pressure dissipation
- Ramp-up, ramp-down injection scenario



Vertical Pressure Dissipation

We model the overburden and underburden with average, anisotropic permeabilities

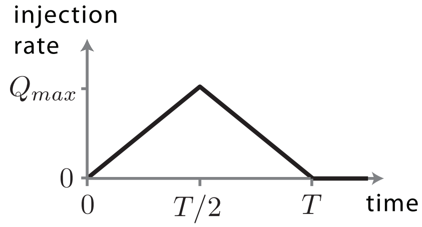


Pressure Storage Capacity

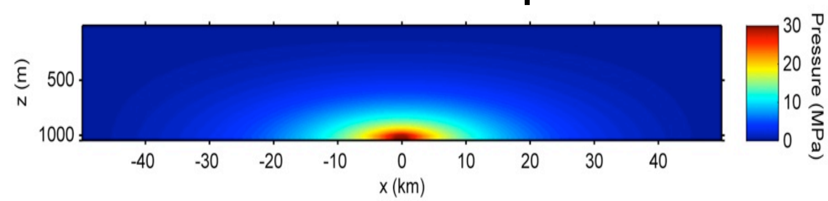
We estimate pressure-limited capacity by using the model in reverse

<u>Forward</u>

set injection scenario

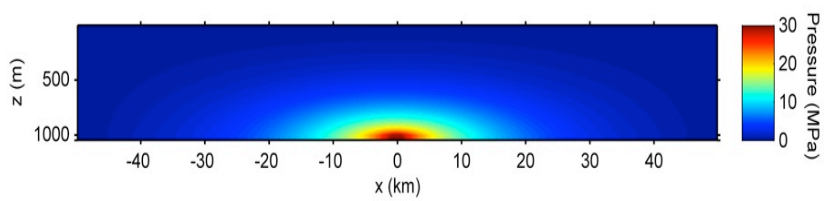


calculate maximum pressure

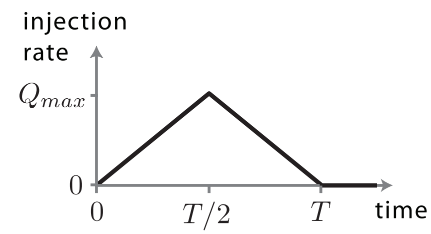


<u>Reverse</u>

set maximum pressure
to fracture pressure

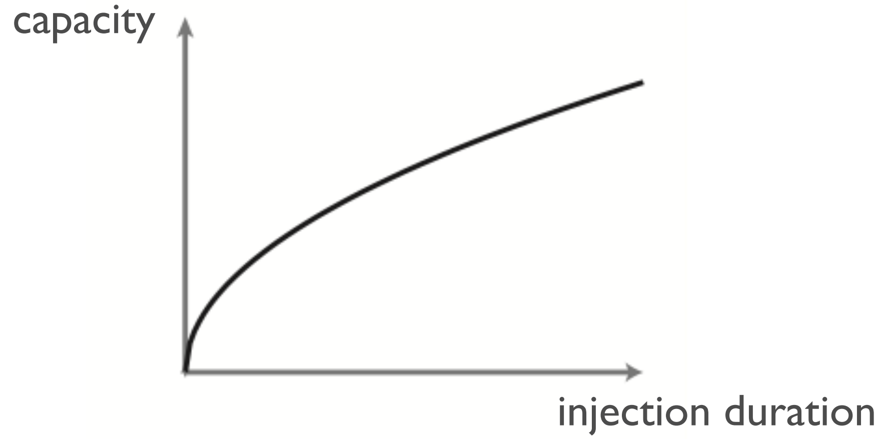


calculate injection scenario
and volume



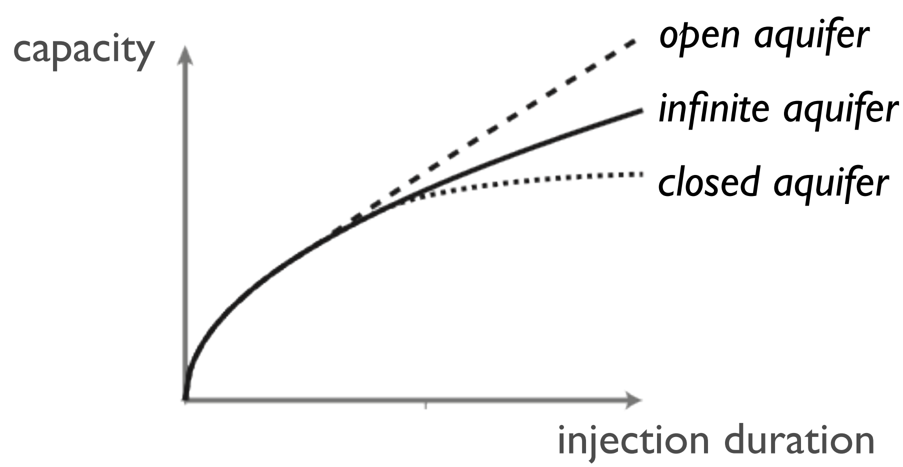
Pressure Storage Capacity

- Pressure capacity depends on the duration of injection *T*
- If the aquifer is laterally infinite and the overburden and underburden are impermeable, then capacity grows as $\sqrt{T}$



Pressure Storage Capacity

If the aquifer is laterally bounded, the capacity growth deviates from $\sqrt{T}$

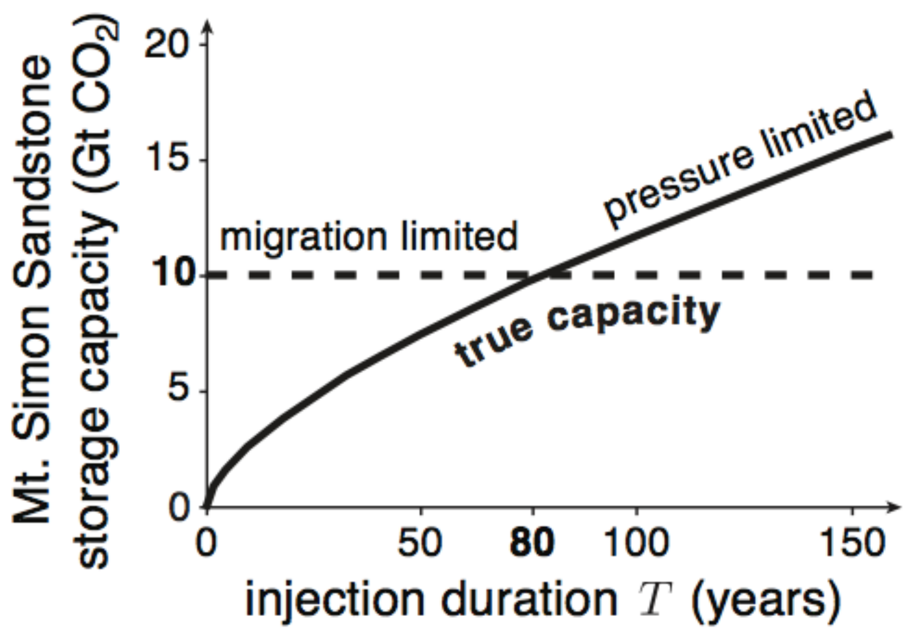


Capacity Estimates from Fluid Dynamics

Szulczewski and Juanes
(*GHGT* 2010)

Storage capacity is dynamic

- For short durations of injection, overpressure is more limiting
- For long durations of injection, CO_2 migration is more limiting

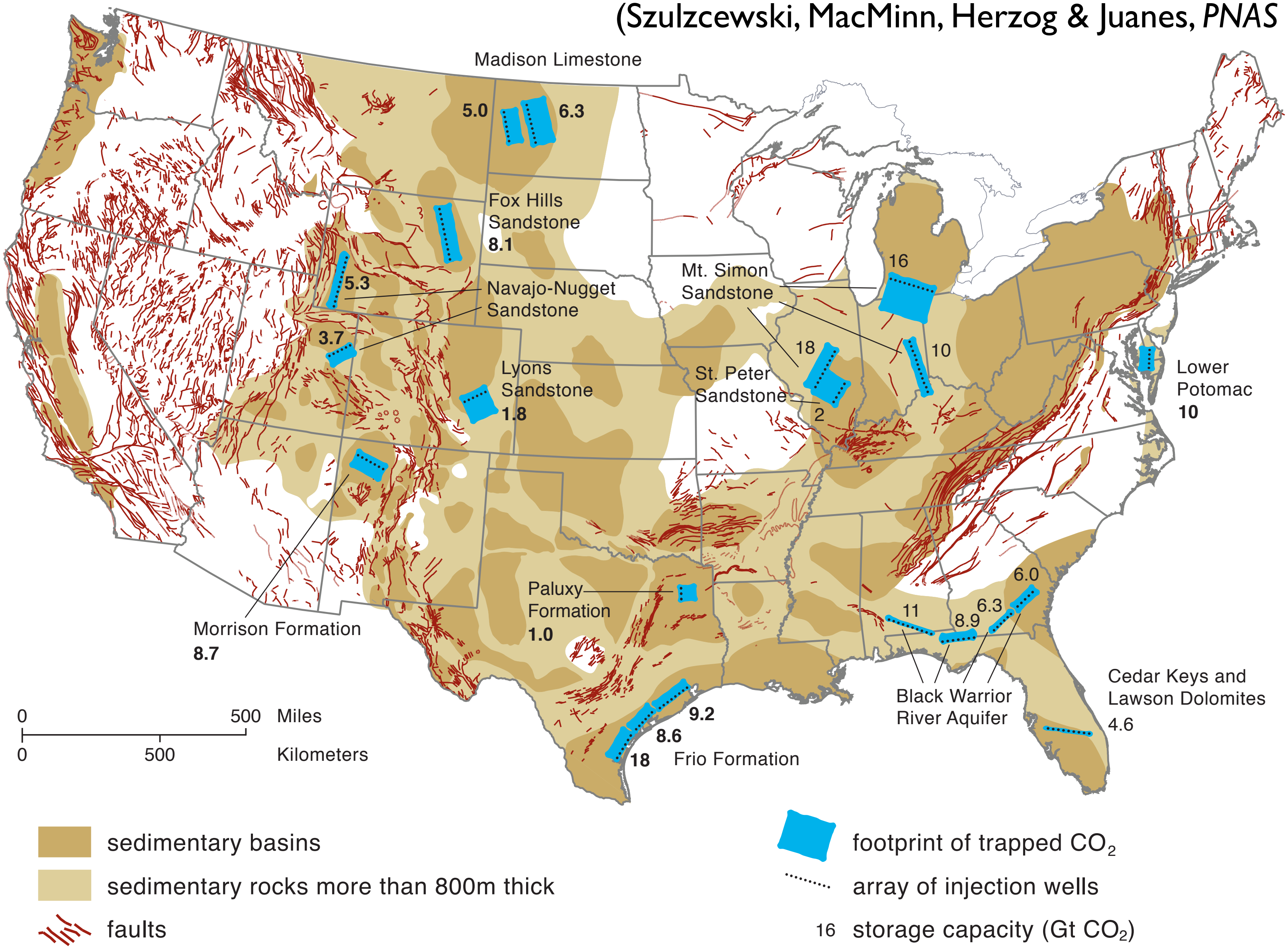


Capacity Estimates for the United States

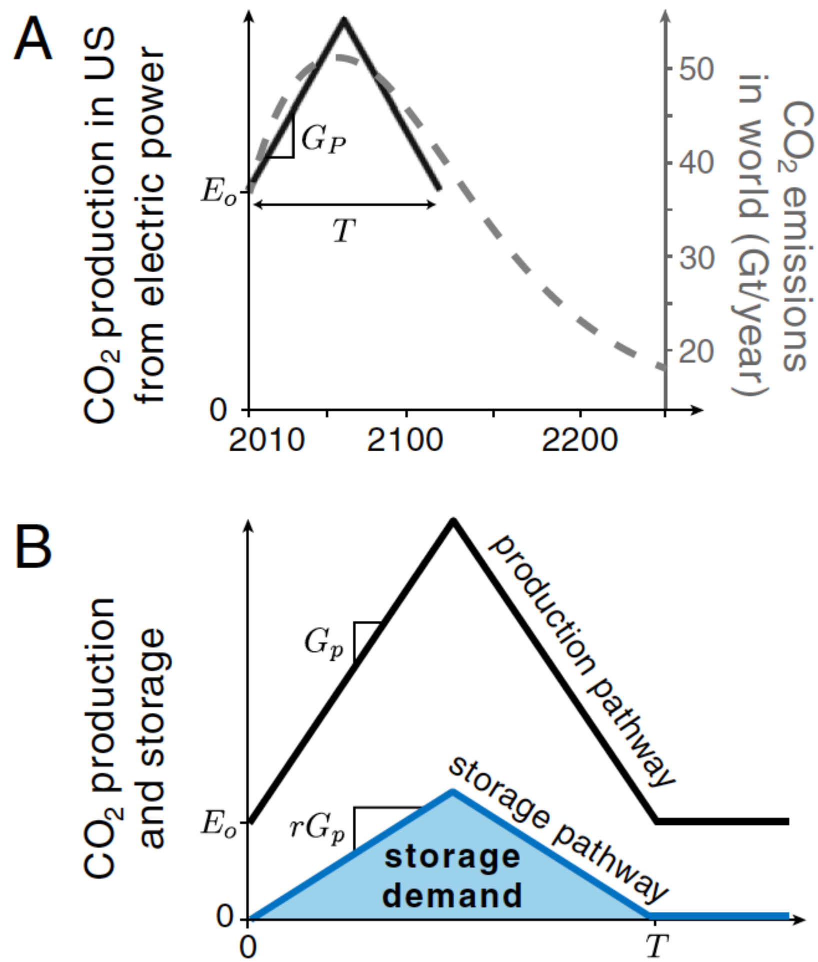
- Studied 20 well arrays in 12 saline aquifers throughout the U.S.
  - Largest, most structurally sound, best characterized aquifers
  - Capacities between 1 and 18 $GtCO_2$
- 8 were limited by pressure, 12 by migration
- Estimates are representative of geologic capacity constraints nationwide

Storage Footprint for 100-year Injection

(Szulzcewski, MacMinn, Herzog & Juanes, *PNAS* 2012)



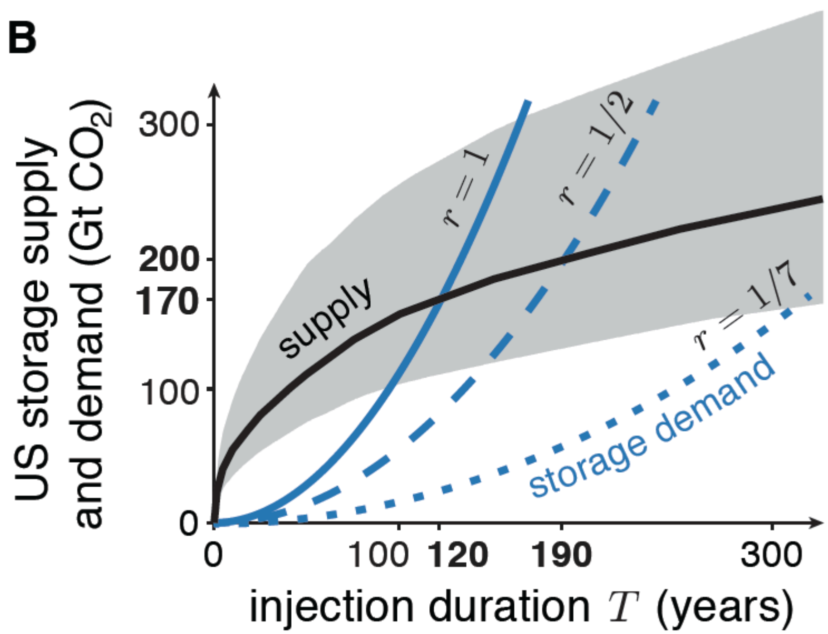
What Does This All Mean for Climate Change Mitigation?



- We adopt a simplified CO_2-production curve that resembles emissions scenarios
- Rates increase during deployment and then decrease during phase-out
- Cumulative storage increases quadratically with injection duration

Supply and Demand Determine CCS Lifetime

- Geologic capacity scales at most as $C \sim T^{1/2}$ ("supply curve")
- Cumulative injection scales as $I \sim T^2$ ("demand curve")



(Szulzcewski, MacMinn, Herzog & Juanes, *PNAS* 2012)

- ***Large-scale implementation of CCS is a geologically-viable climate-change mitigation option in the United States over the next century***

Summary of Results

- Storage capacity is dynamic, and depends on duration of injection: both CO_2 migration and pressure dissipation may limit storage capacity
- Storage capacity in underground formations imposes a constraint, which is dependent on the CCS injection scenario
  - Cumulative injection scales as $I \sim T^2$ ("demand curve")
  - Geologic capacity scales at most as $C \sim T^{1/2}$ ("supply curve")
- The crossover of these two curves constrains the life span of CCS
  - In the case of the United States, this is in the range of 100-200 years

Carbon Capture and Storage (CCS)

- <u>Can CCS be a bridge solution</u> to a yet-to-be-determined low-carbon energy future?

Lifetime of carbon capture and storage as a climate-change mitigation technology

Michael L. Szulczewski[a], **Christopher W. MacMinn**[b], **Howard J. Herzog**[c], **and Ruben Juanes**[a,d,1]

Departments of [a]Civil and Environmental Engineering and [b]Mechanical Engineering, [c]Energy Initiative, and [d]Center for Computational Engineering, Massachusetts Institute of Technology, Cambridge, MA 02139

Edited by M. Granger Morgan, Carnegie Mellon University, Pittsburgh, PA, and approved February 15, 2012 (received for review September 19, 2011)

- ***CCS is a geologically-viable climate-change mitigation option in the United States over the next century*** (Szulczewski et al., *PNAS* 2012)

Earthquake triggering and large-scale geologic storage of carbon dioxide

Mark D. Zoback[a,1] **and Steven M. Gorelick**[b]

Departments of [a]Geophysics and [b]Environmental Earth System Science, Stanford University, Stanford, CA 94305

Edited by Pamela A. Matson, Stanford University, Stanford, CA, and approved May 4, 2012 (received for review March 27, 2012)

- ***CCS is a risky, and likely unsuccessful, strategy for significantly reducing greenhouse gas emissions*** (Zoback and Gorelick, *PNAS* 2012)

- <u>Is CO_2 leakage really a show-stopping risk?</u>

No geologic evidence that seismicity causes CO_2 leakage through faults

- Zoback & Gorelick's line of argument:
  - Maps of earthquakes epicenters show earthquakes occurring almost everywhere, suggesting Earth's crust is near critical state
  - Overpressure from CO2 injection will trigger earthquakes within the reservoir and the caprock
  - They take for granted that this will cause leakage through faults

No geologic evidence that seismicity causes CO_2 leakage through faults

- Zoback and Gorelick articulate an important, albeit well-known, concern: CCS may induce seismicity, as can other subsurface technologies. However, their characterization misrepresents its relevance to CCS.

  - The vast majority of earthquakes are much deeper than CO2 storage reservoirs.
  - Sedimentary rocks can undergo substantial deformation without establishing leaking pathways, in contrast with brittle basement rocks
  - Link between fault slip and leakage is tenuous for sedimentary rocks: hydrocarbon reservoirs have existed for millions of years in regions of intense seismic activity (e.g., Southern California)
  - While induced earthquakes and leakage risk could compromise particular CCS projects (they mention the Mountaineer project), many geologic formations exhibit excellent promise for storing CO2

The debate is far from settled …

LETTER

Juanes et al. (*PNAS* 2012)

No geologic evidence that seismicity causes fault leakage that would render large-scale carbon capture and storage unsuccessful

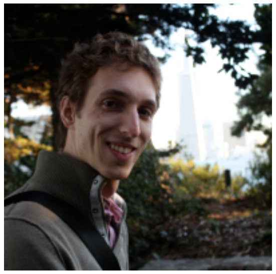
LETTER

Zoback and Gorelick (*PNAS* 2012)

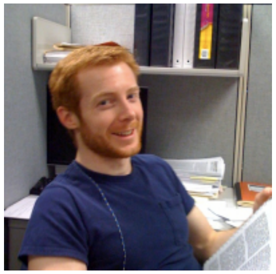
Reply to Juanes et al.: Evidence that earthquake triggering could render long-term carbon storage unsuccessful in many regions

Acknowledgments

- Students



Chris MacMinn



Mike Szulczewski

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