Modelling CO_2 Injection and Storage

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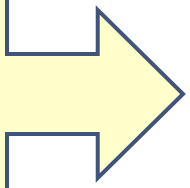
Special thanks to colleagues in Statoil CO2 Storage R&D Project, the In Salah JIP (BP, Statoil, Sonatrach) & Permedia Research

Geological Storage of CO_2

1. The basic concept is to store captured CO_2 underground in reservoirs that would otherwise contain water, oil or gas
2. We need to be deep (greater than 800m) to ensure CO_2 is in a dense form – the super-critical phase
3. These are also the depths where we are confident that natural gas has been trapped for millions of years
4. But the big questions are:
   - Where do we store it?
   - How much CO_2 can we inject?
   - Can we store it safely?
   - Can we store it cost-effectively?

Reservoir modelling is the way we **quantify** the **answers** to these **engineering** questions



Outline

1. Why model? (The purpose of modelling)
2. What do we need to model? (Physics, chemistry, geology)
3. What are the elements of modelling? (Tools, concepts)
4. Some examples (What factors turn out to be most important)

Why model?

When climate scientists tried to explain to management that their long-term forecasts were highly uncertain, the reply came that ...

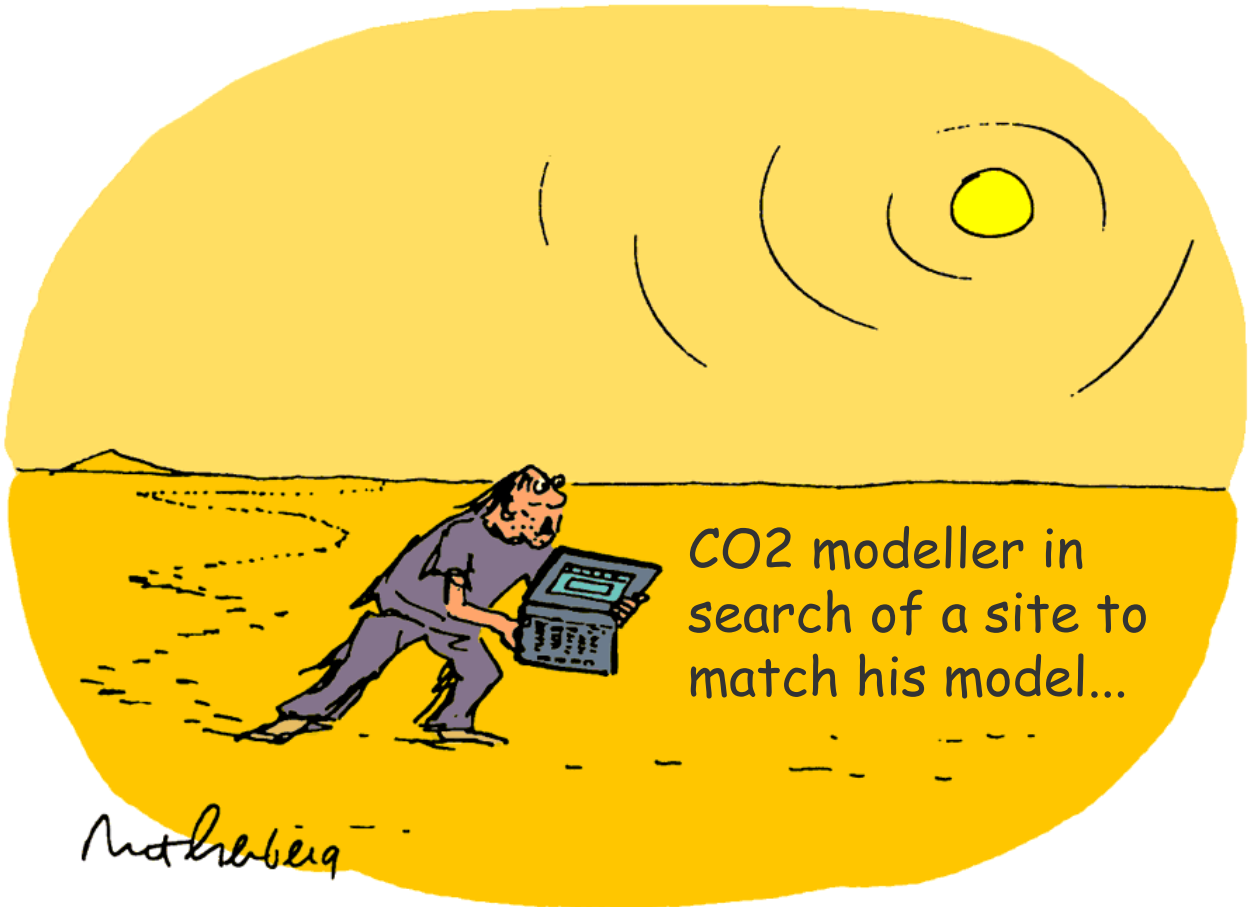
“The director general is quite aware that your predictions are meaningless ...

... but he needs them for planning purposes.”

Against the Gods: The Remarkable Story of Risk, by Peter L. Bernstein, 1998.

“Garbage in, garbage out!”

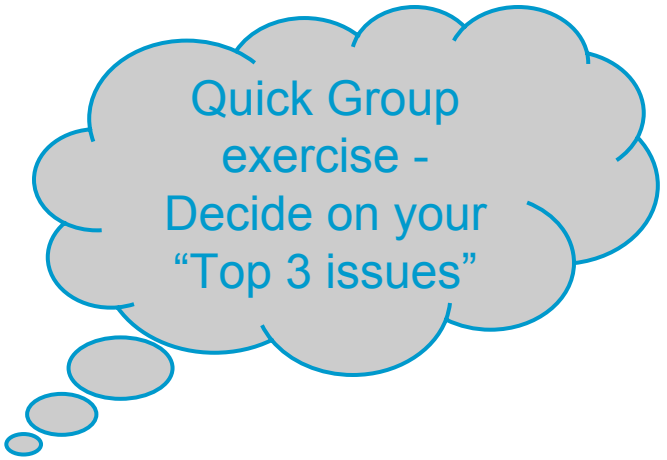
Why model?



- The purpose of modelling is:
  To capture knowledge of the subsurface in a quantitative form in order to make engineering decisions.
- We cannot predict but we can make good estimates of the likely outcome – modelling is a form of forecasting

What do we need to model?

- CO2 phase behaviour
- Multi-phase flow
- CO2 dissolution in brine
- Rock architecture (permeability, porosity)
- Unexpected barriers and faults
- Rock-fluid interactions (surface chemistry)
- Rock mechanical effects
- Topography of top reservoir surface
- Well design and engineering
- Numerical representations of flow processes
- Effects of compositional impurities in gas or brine phase
- ...



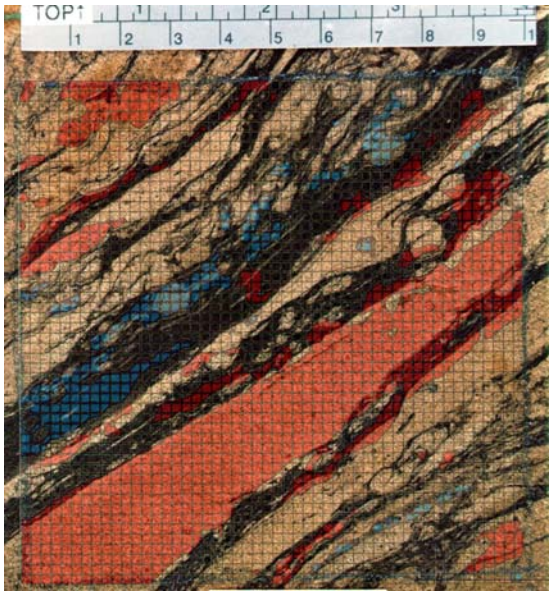
Review your answer after the case studies ...

What are the modelling elements?

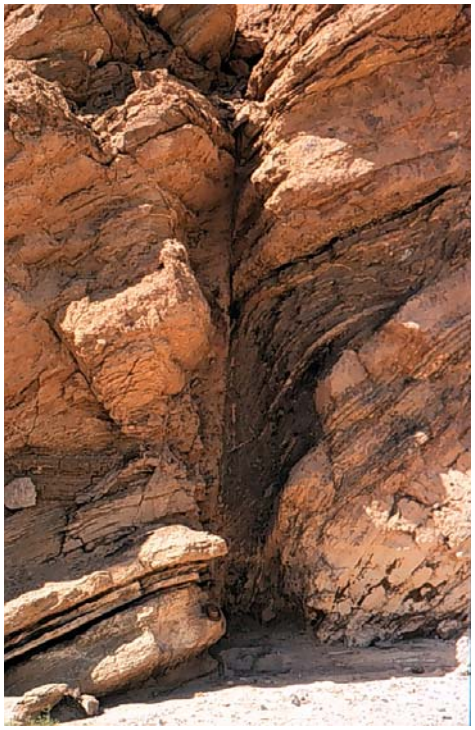
1. A numerical representation of subsurface geology
    - Geological reservoir modelling
    - Complex and time-consuming workflows
2. Appreciation of the relevant physics and chemistry
    - High-school and grad school text-books (maybe even Wiki!)
    - “Back of the envelop” estimates (know what you are modelling)
3. Maths and computation:
    - Appreciate what the software package is trying to do
    - Read the manual

Geological Controls

- Effects of reservoir geology on CO2 injection and storage are critical (but difficult to quantify)
- Good appreciation of geology is essential



Lamina-scale permeability variations (Tilje Fm., Norway)



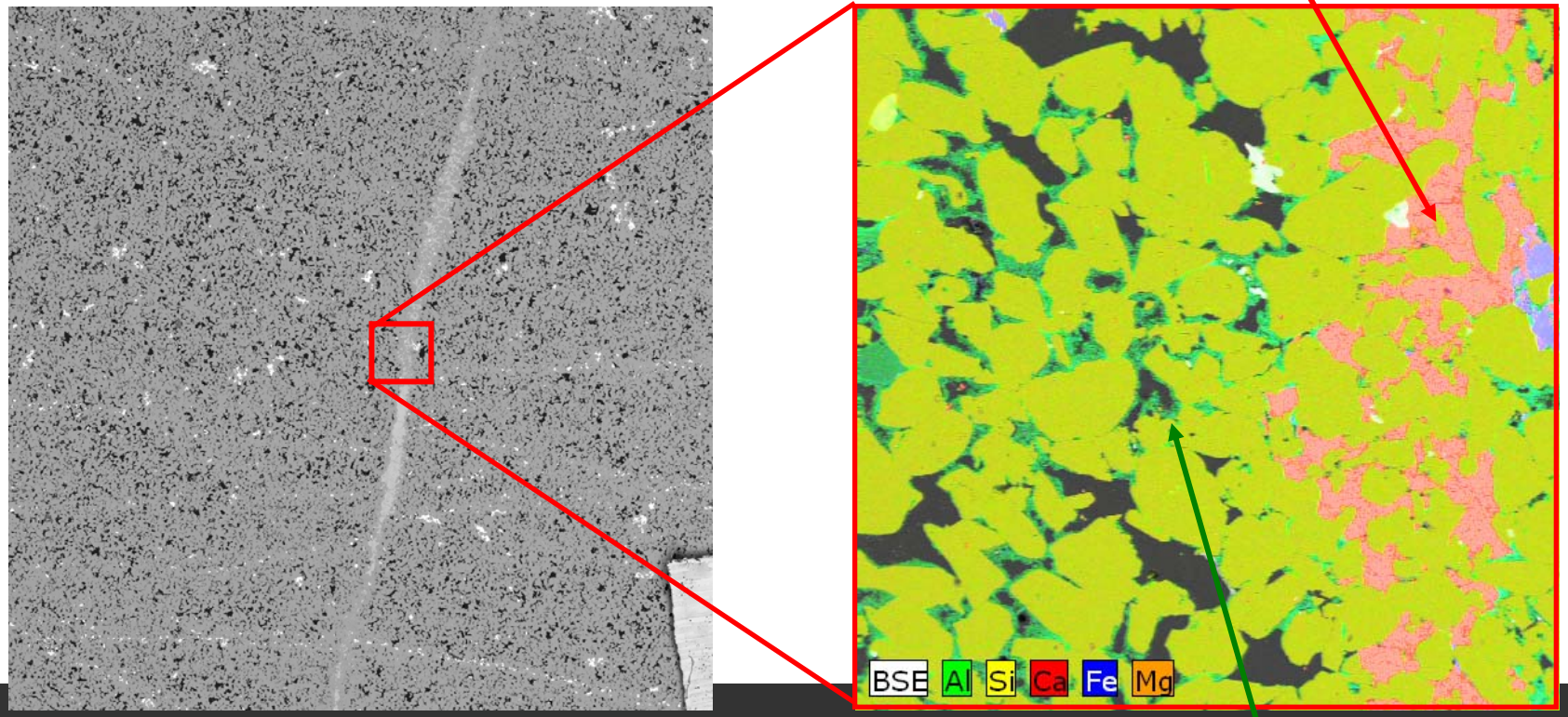
Normal fault gouge with clay smear (Sinai, Egypt)

Tidal Delta Sedimentary Architecture (Niell Klinter Formation, Greenland)

Fluid-rock interactions

- Petrophysical characterisation of the pore space is important
- Recent geochemical work at In Salah shows that CO2-rich brines react to create Fe-carbonate cements similar to natural cementation processes
- It's complicated but… the system seems to be self-healing

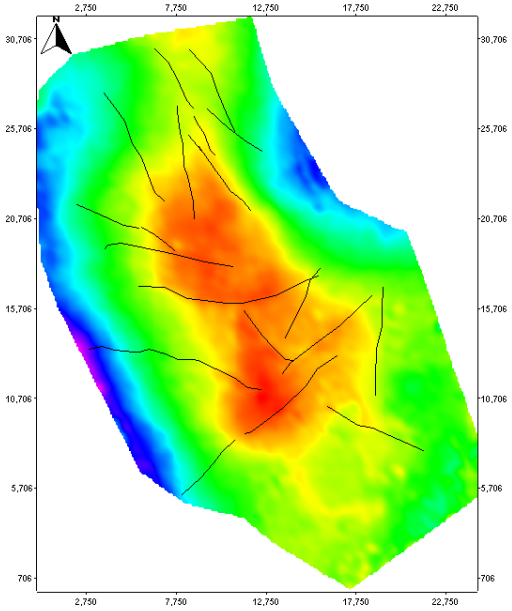
Natural cemented fracture – In Salah (JIP1)



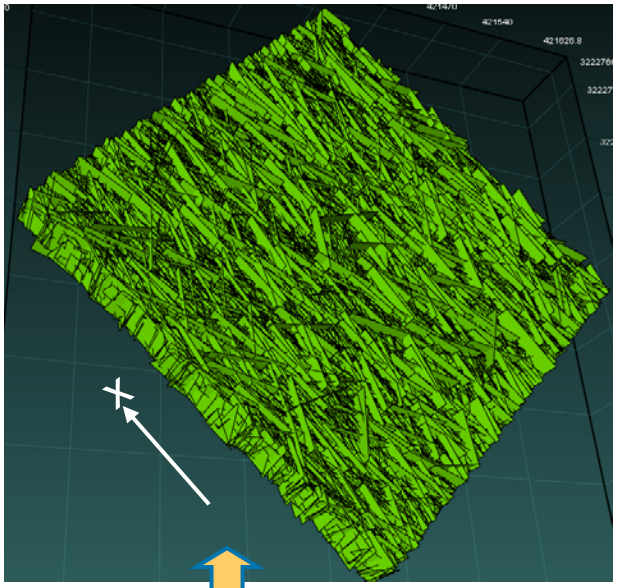
Example workflow – Krechba

- Tools used: GoCad > RMS > Eclipse > Abacus > Fraca+
- See Iding & Ringrose, 2010

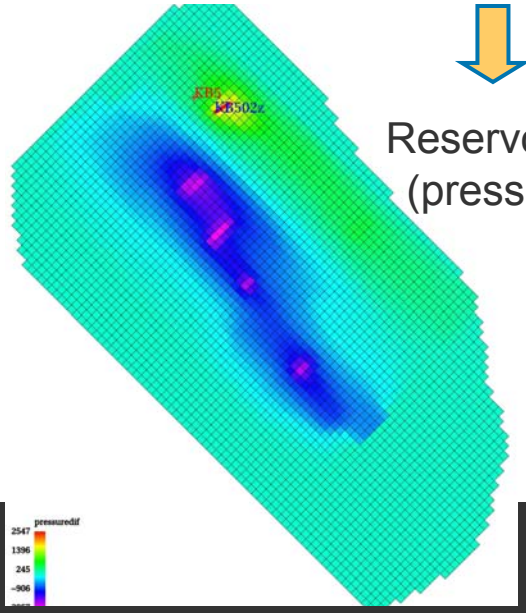
Structural geological model

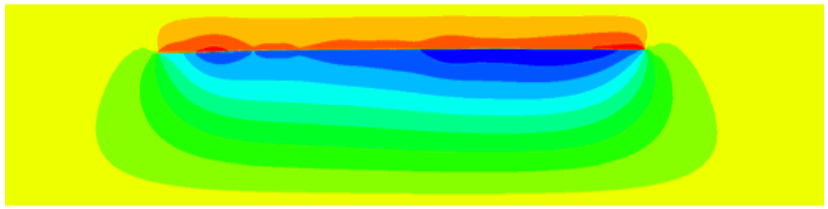


Fractured rock property model (effective permeability)



Reservoir simulation (pressure and flow)

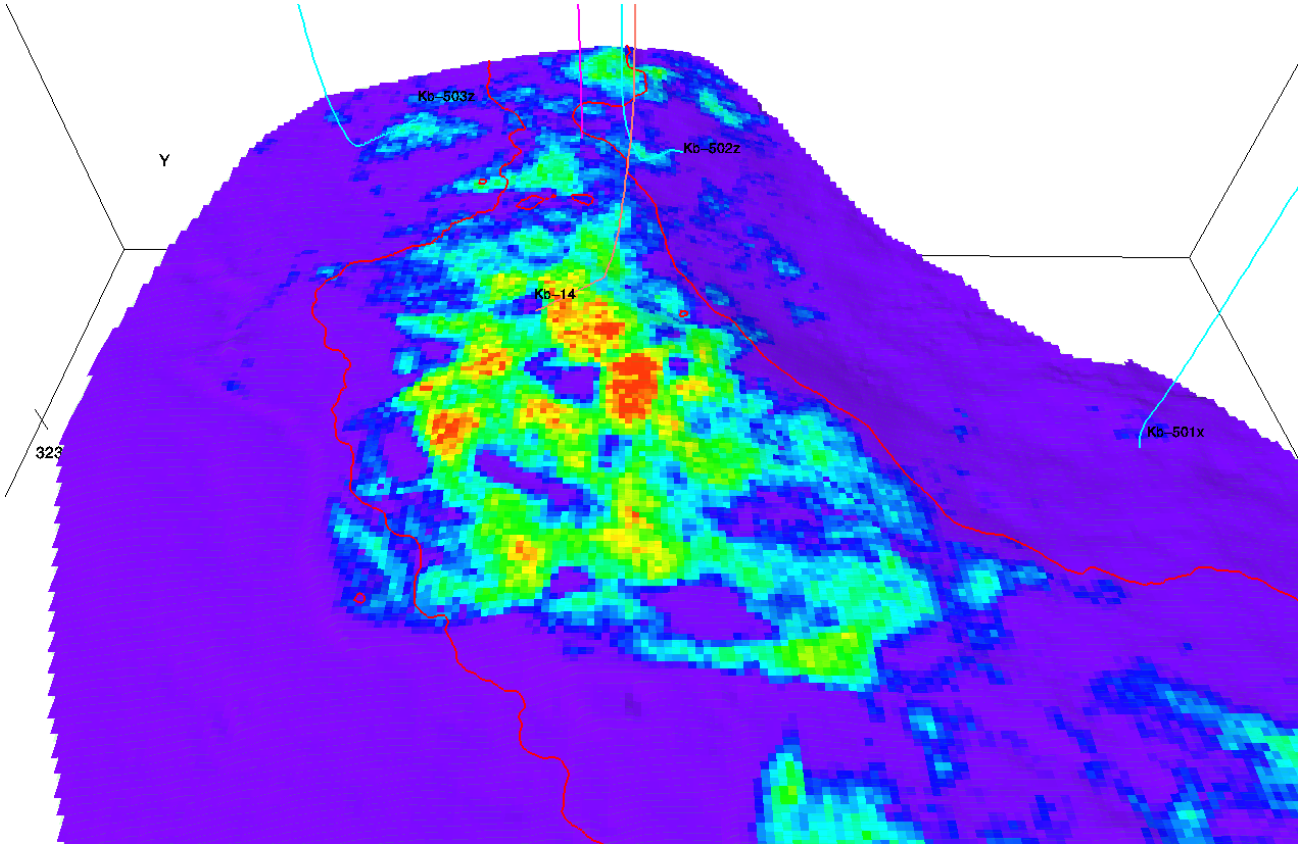




Geomechanical model (stress & strain)

Example Property Modelling

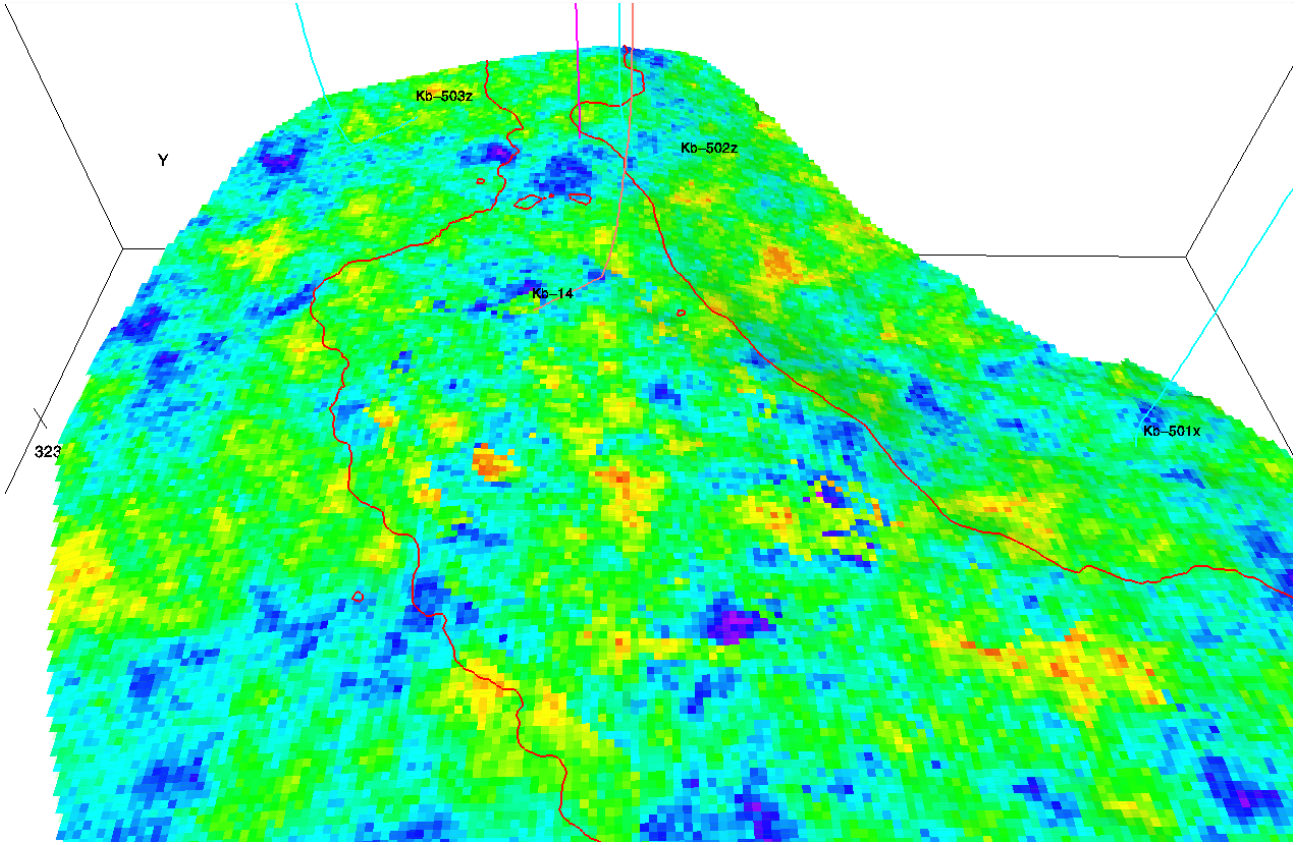
(Krechba, preliminary test case)



Seismic porosity estimate

Example Property Modelling

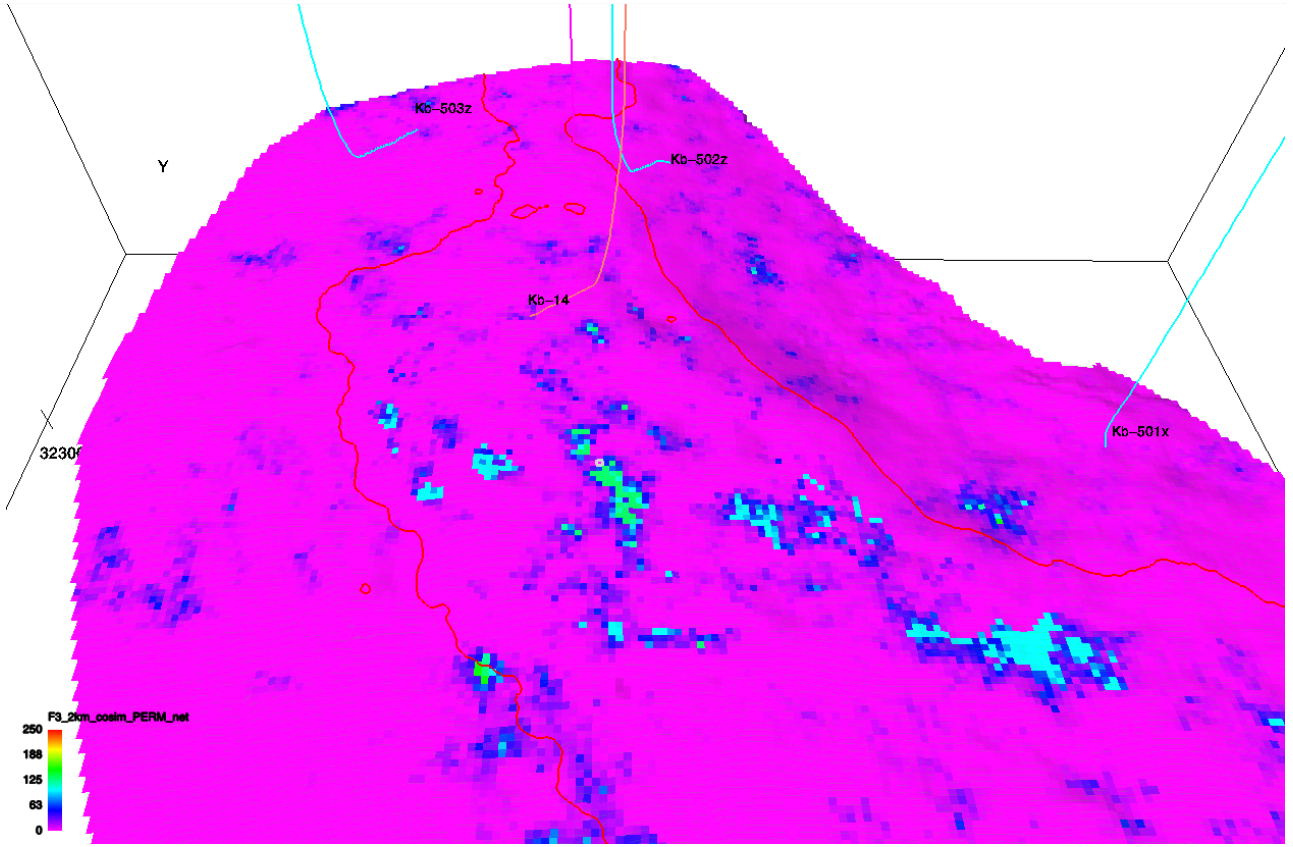
(Krechba, preliminary test case)



Co-simulated porosity wells and seismic

Example Property Modelling

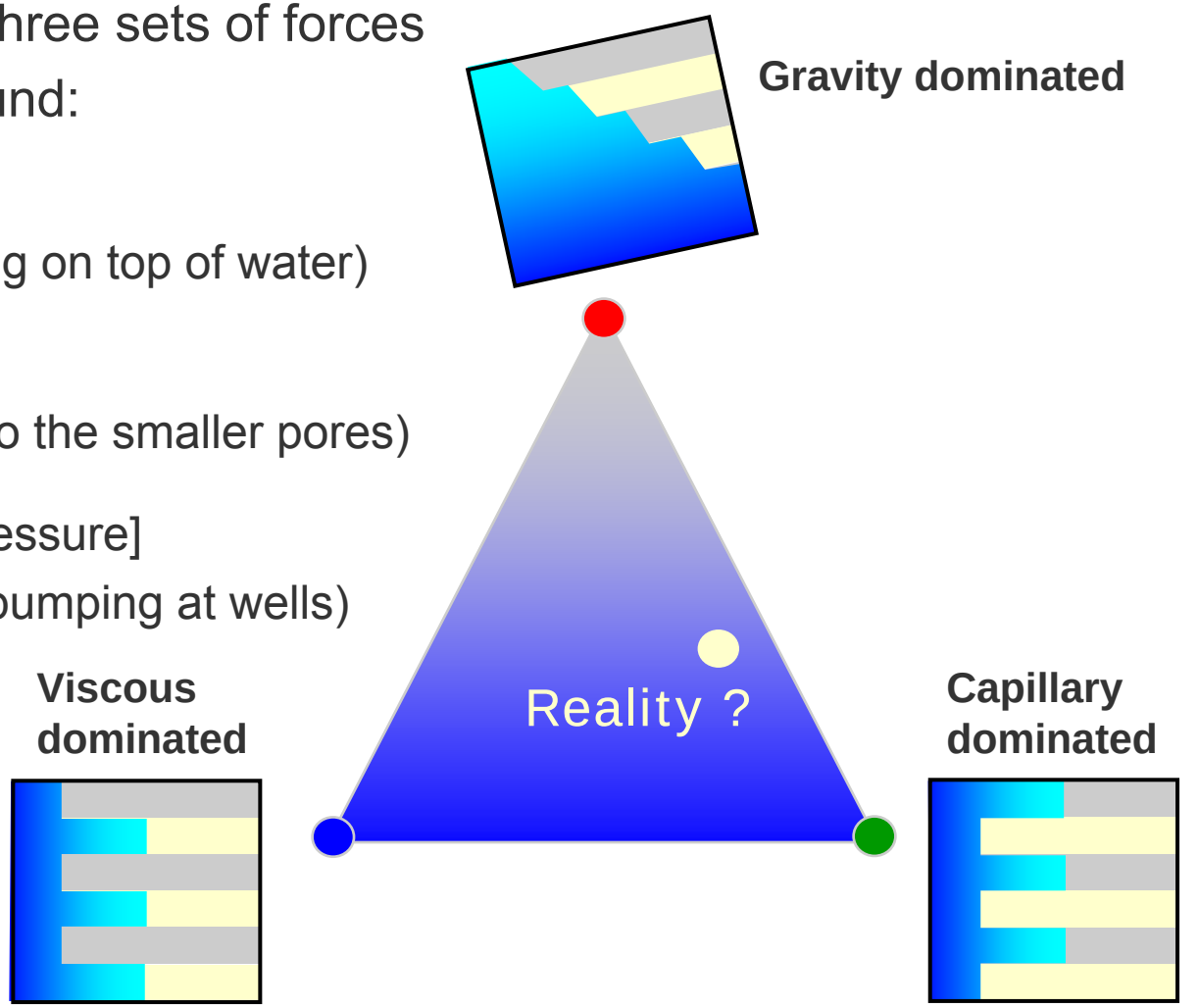
(Krechba, preliminary test case)



Co-simulated permeability

Appreciation of the relevant flow physics

- There are essentially three sets of forces pushing the fluids around:
  - —**Gravity**
    (e.g. gas likes floating on top of water)
  - —**Capillary**
    (e.g. water soaks into the smaller pores)
  - —**Viscous** [applied pressure]
    (e.g. engineers like pumping at wells)



Multiphase Flow (101)

- For two-phase immiscible flow (e.g. gas and water), the two-phase Darcy equation and an interfacial pressure equation are used:

$$\underline{u}_o = -\underline{\mathbf{k}}\, k_{rg} / \mu_g \,.\, \nabla (P_g + \rho_g g z)$$

$$\underline{u}_w = -\underline{\mathbf{k}}\, k_{rw} / \mu_w \,.\, \nabla (P_w + \rho_w g z)$$

$$P_c = P_g - P_w$$

$\underline{\mathbf{k}}$ is absolute permeability tensor

$\underline{\mathbf{k}}k_{rg}$ could be replaced by

$\underline{\mathbf{k}}_g$ the phase permeability tensor

where

g and w refer to the oil and water phases,

k_{rw} and k_{rg} are the relative permeabilities

μ and ρ are viscosity and density.

P_c is the capillary pressure

∇P is the pressure gradient

$$\nabla P = \frac{dP}{dx} + \frac{dP}{dy} + \frac{dP}{dz}$$

Relative Permeability Basics

- The most common functions used for relative permeability are the Corey exponent functions:

$$k_{ro} = A(1-S_{wn})^x$$

$$k_{rw} = B(S_{wn})^y$$

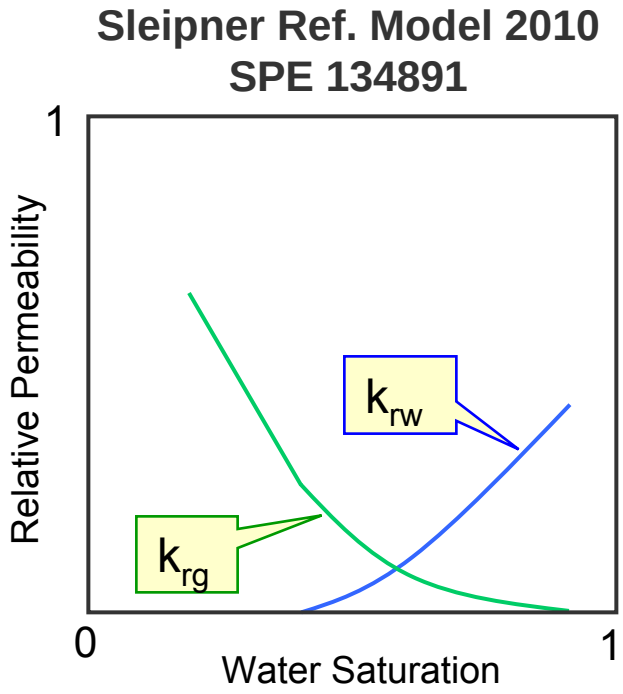
where S_n is the normalized saturation,

$$S_{wn} = (S_w-S_{wc})/(S_{wor}-S_{wc})$$

- Typical values for a water-wet light oil would be

$$k_{ro} = 0.85(1-S_{wn})^3$$

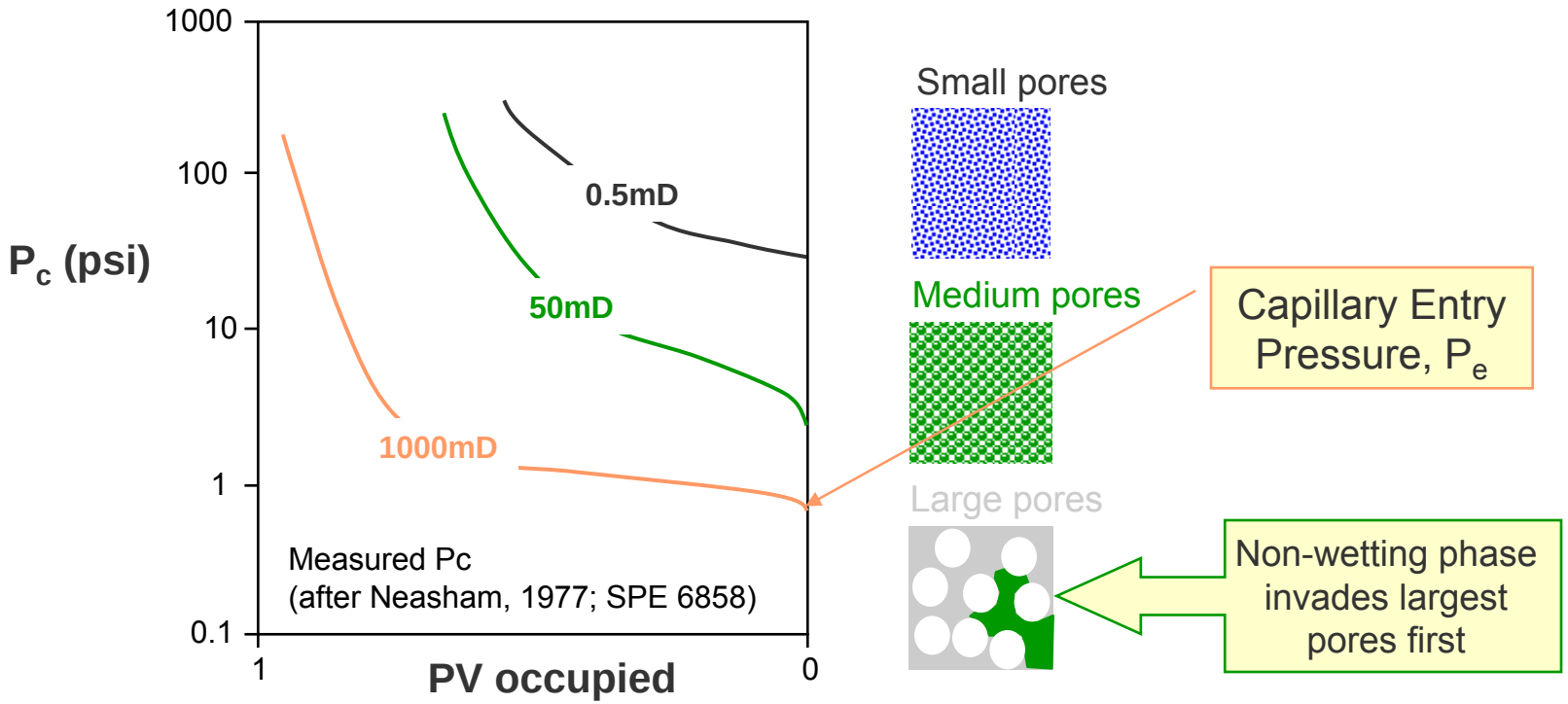
$$k_{rw} = 0.3(S_{wn})^3$$



- Functions for CO2-brine systems are much debated
  - Stanford Rel perm explorer is a useful took:
    http://pangea.stanford.edu/research/bensonlab/relperm/index.html

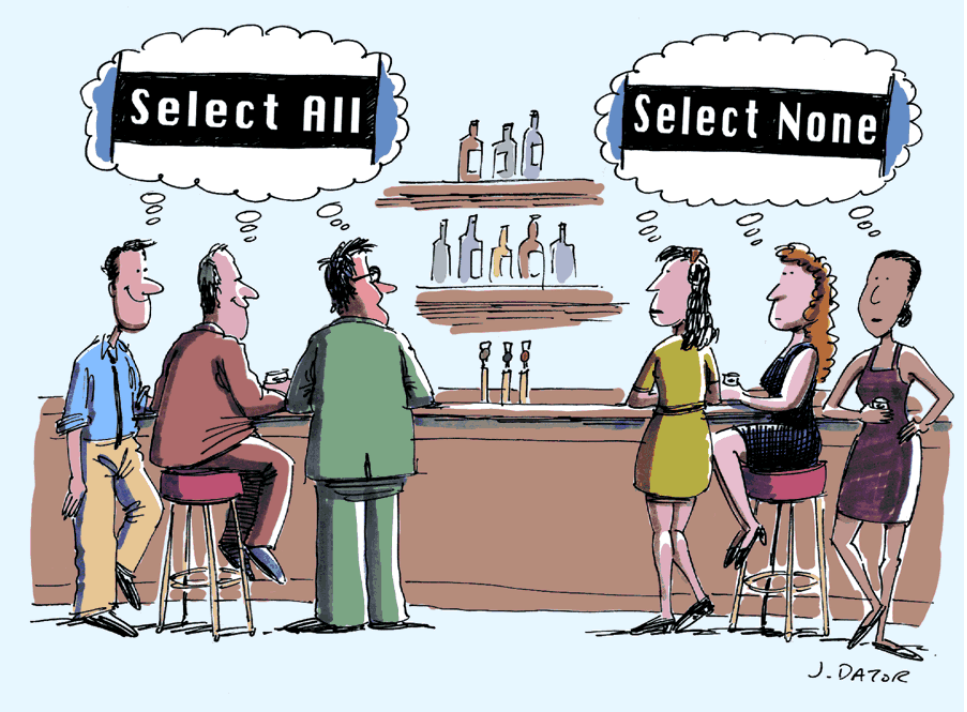
The Capillary Pressure Curve

- The capillary pressure curve is a “summary” of fluid-fluid interactions
- By definition, $P_c = P_{\text{non-wetting phase}} - P_{\text{wetting-phase}}$ [Pc = f(S)]
- But note that P_c is the difference between gas/oil and water pressure across all the oil/water interfaces within the porous medium



Maths & Computation

- Defining an appropriate grid for simulation is a difficult task requiring care and experience

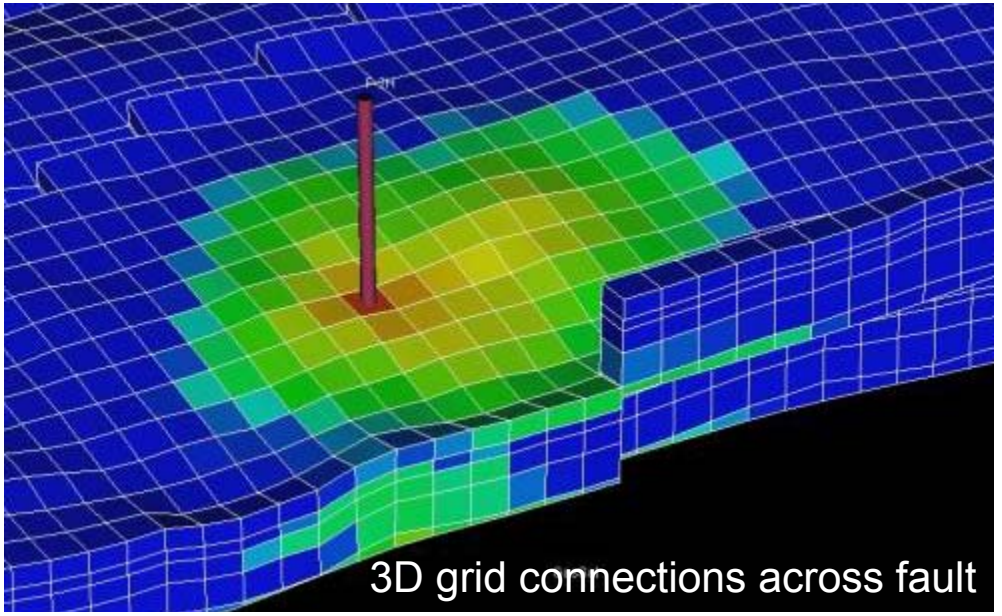


You need to:

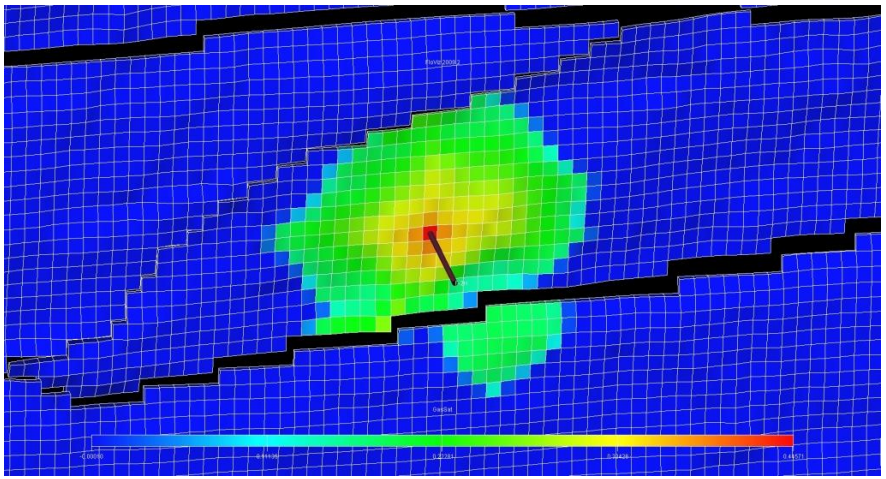
1. Appreciate what the software package is trying to do:
   - e.g. estimate fluxes between grid centres across cell faces (finite difference, 5-point stencil)
2. Read the manual...
   ... which is usually out of date so ask someone who has most recently used that function!
3. Learn to differentiate between “good enough” and “wildly inaccurate”

Example flow grid

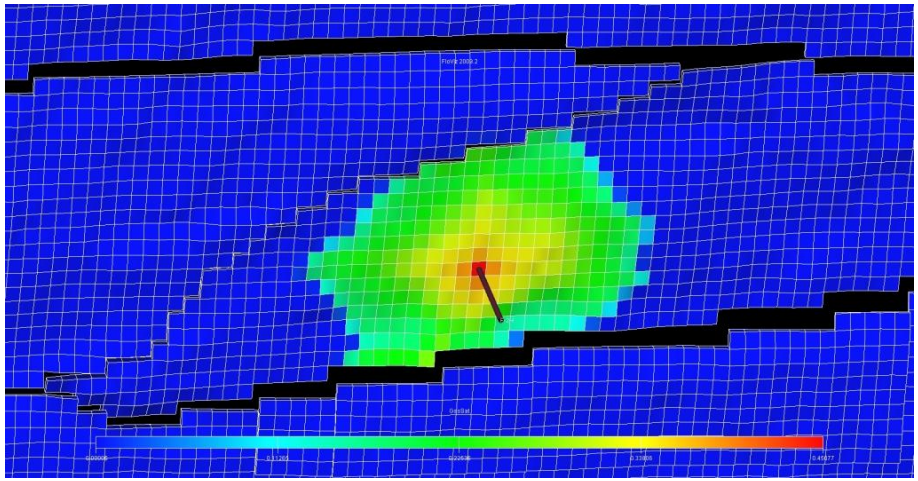
- Snøhvit fault sensitivity test case
- Statoil Summer Student Project
- Laure-Hélène Garaffa (U. Nancy)
- CO2 plume distribution for different fault seal cases



With fault juxtaposition but no seal



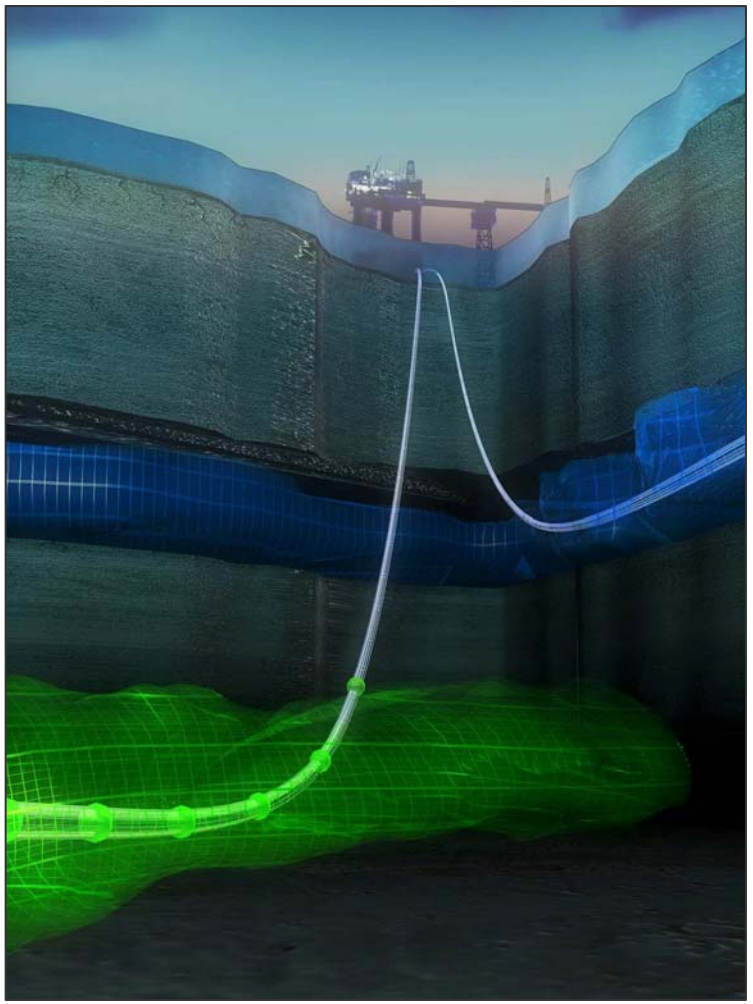
With disconnected faults



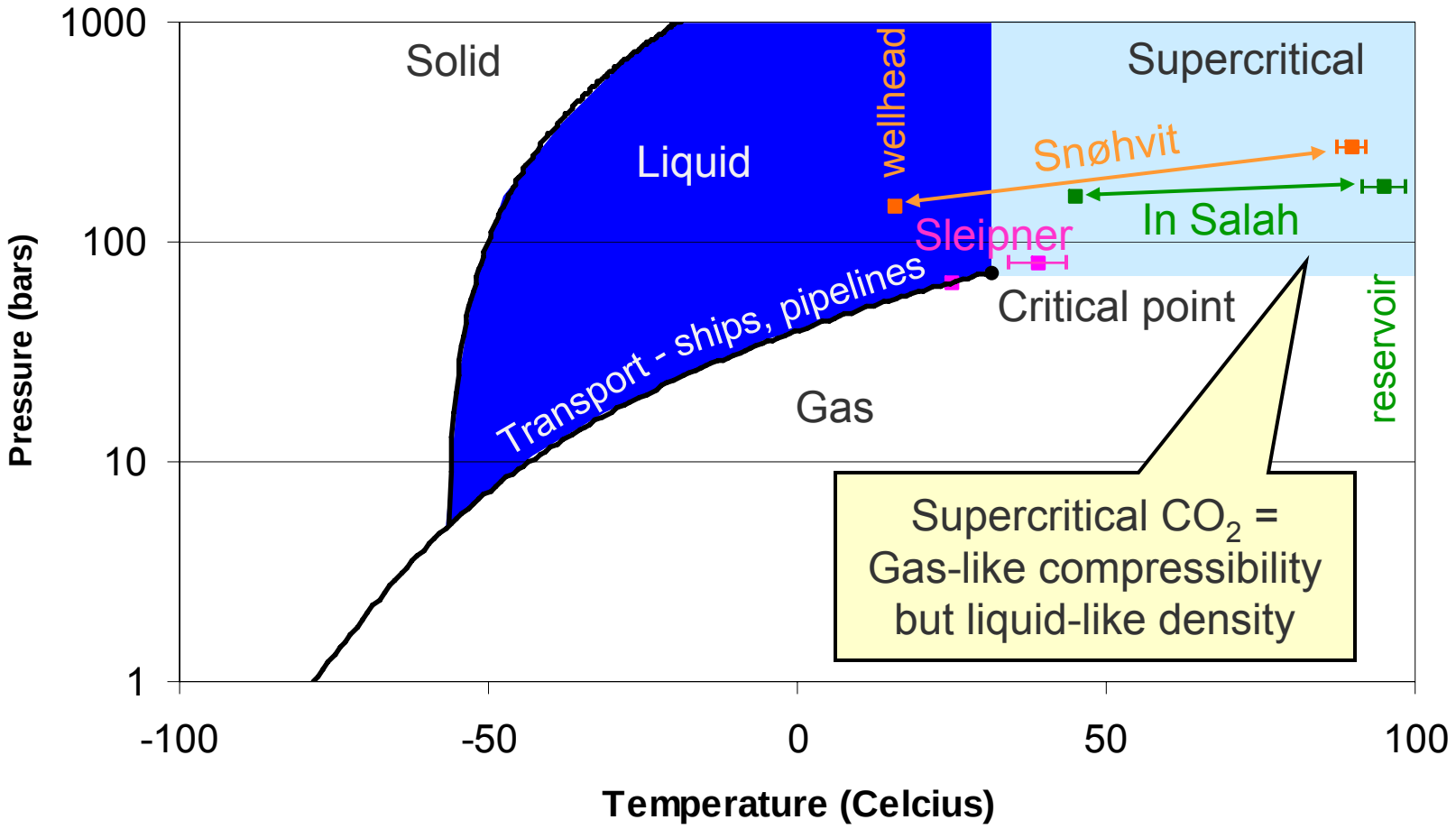
Case Studies (Sleipner, In Salah)

Sleipner Overview

- CO_2 from the Sleipner field is stored in the Utsira Formation, North Sea.
- Reservoir unit at 800-1100 m depth.
- One CO_2 injector.
- Injected gas is ~98% CO_2.
- 11.4 Million tons CO_2 have been injected (1996-Dec 2009).
  - —Wellhead pressure stable at ~65 bar
  - —Wellhead temperature held at 25°C
- Some key refs – Hansen et al 2005, Chadwick et al. 2010.

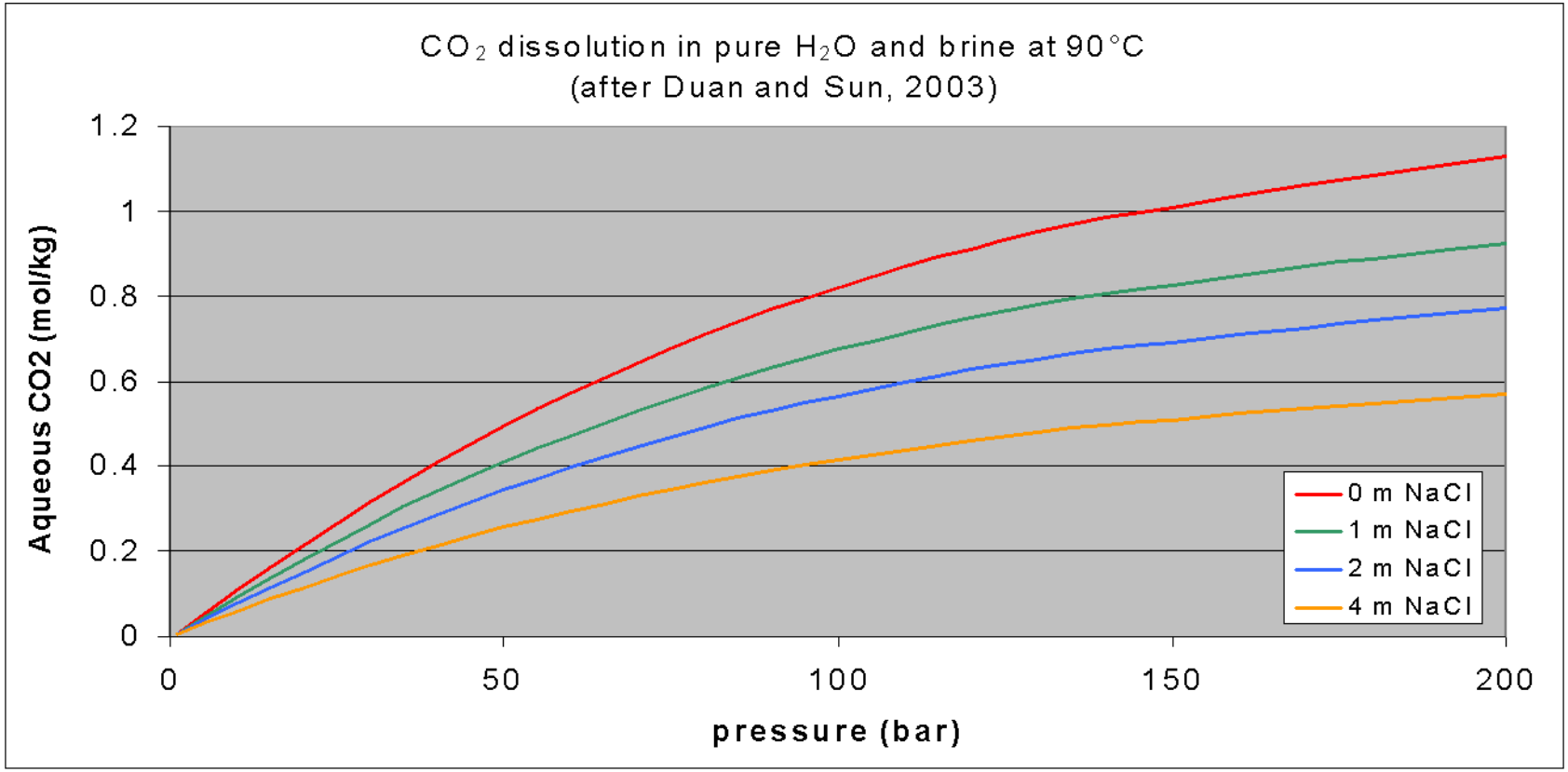


CO_2 Injection and Phase Behaviour



CO_2 solubility in water and brine

- CO_2 solubility increases with pressure (and decreases with temperature)
- Increasing salinity also reduces CO_2 solubility

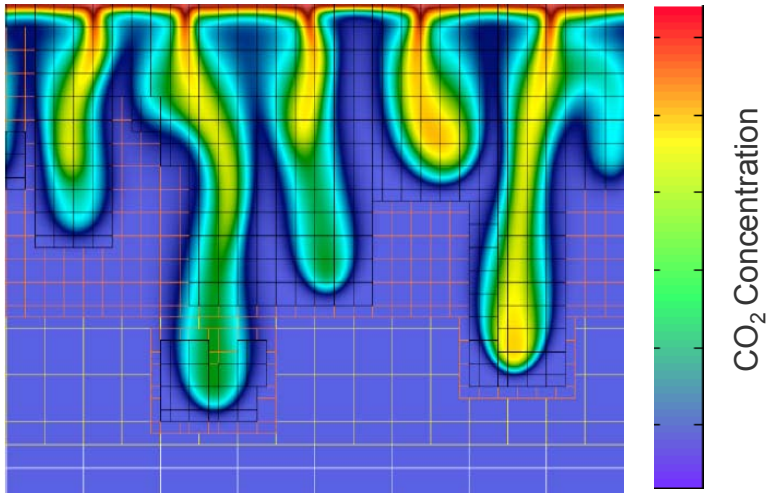


So what actually controls CO_2 Dissolution?

- CO_2 dissolution in brine has an important potential to assist and stabilise long-term storage, but estimates of the effect vary enormously
- We know that convective mixing >> molecular diffusion
- The diffusive boundary level needs to achieve a critical thickness before convection can occur
- Critical time (t_c) for onset of convection and the characteristic wavelength (λ_c) are estimated to be in the range of:
  - 10 days < t_c < 2000 Years
  - 0.3 m < λ_c < 200 m
  - Riaz et al., 2006.

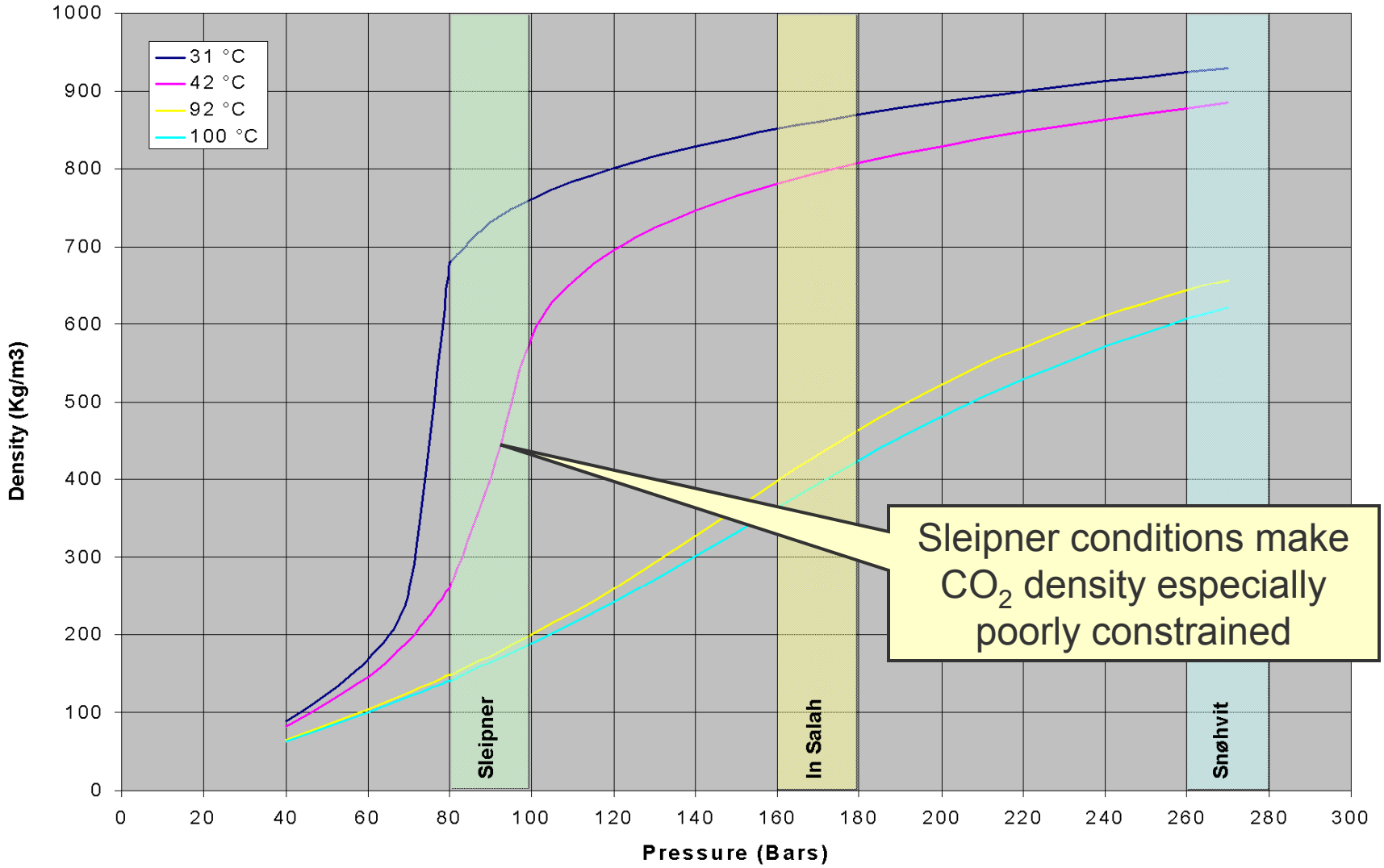
Scope for reducing these ranges using:

- ➢Field Case Histories
- ➢Large-scale lab experiments
- ➢Good geological models

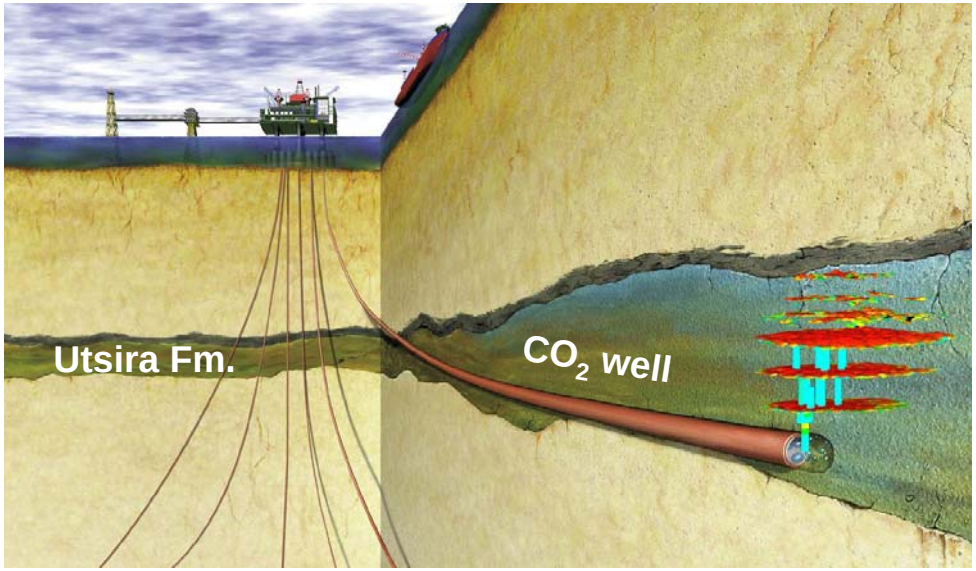


Density-driven flow in CO_2 storage in saline aquifer, Pau *et al*, 2010.

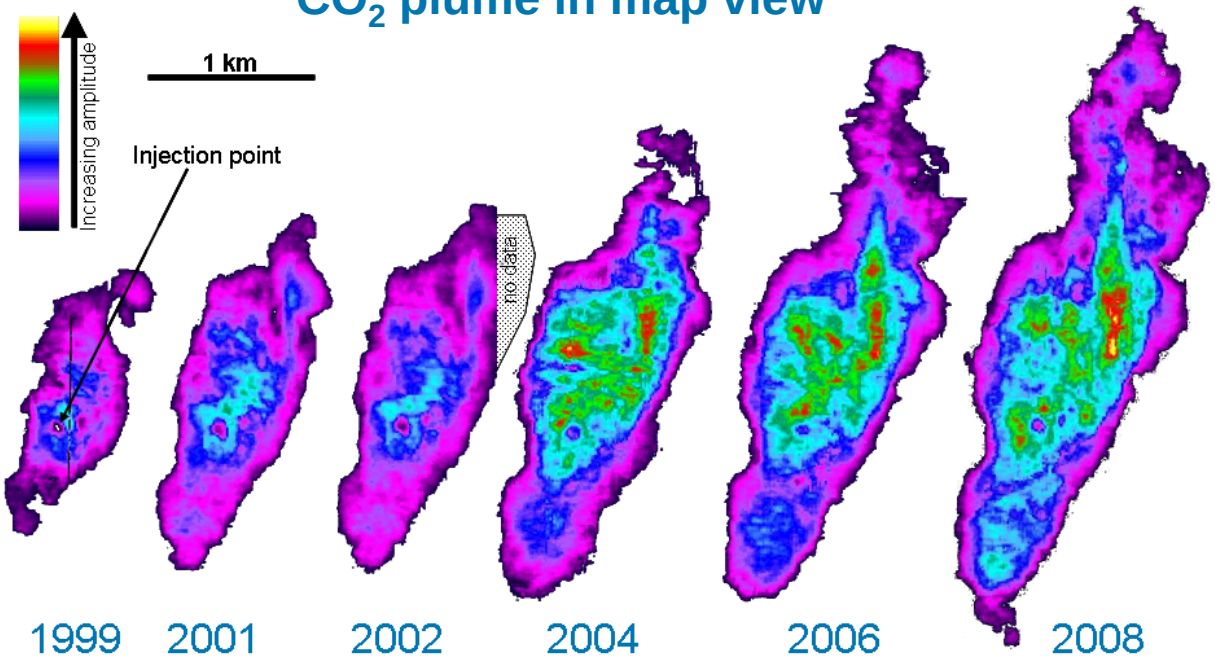
Density Functions for Pure CO_2

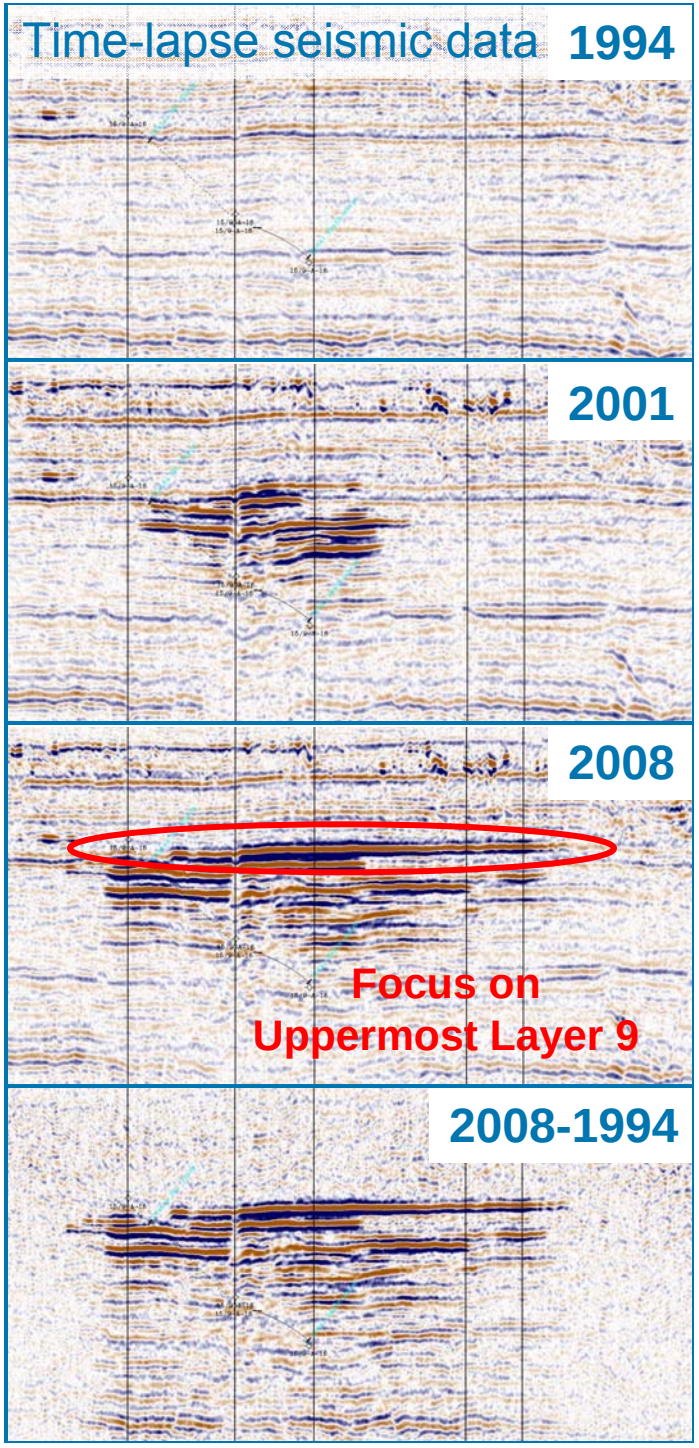


Sleipner 4D Seismic



CO_2 plume in map view

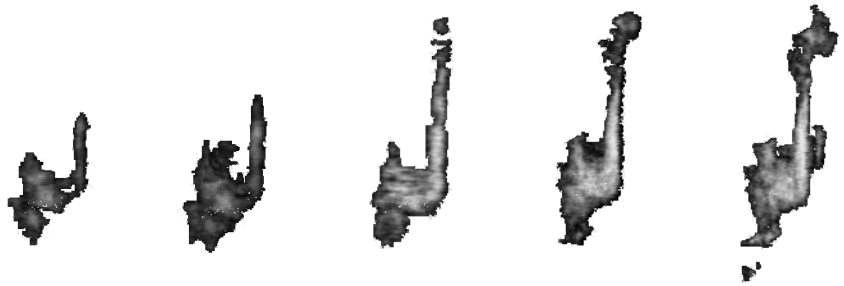




Sleipner Modelling Insights

- Initial models built from pre-injection seismic:
  - Coarse grid simulations which indicated a circular, dispersed plume.
- 4D monitoring data indicates a northerly extension to the plume propagation.
- IP modeling (Permedia Migration tool) gave closer matches to the seismic, indicating a dominance of gravity/buoyancy forces over viscous forces.
- Adjusted inputs to conventional reservoir simulations in order to capture enhanced gravity segregation and understand physio-chemical prosesses:
  - Gives better matches to seismic
  - Shows importance of Vertical Equilibrium (VE) assumption
  - Suggests dissolution was previously overestimated
- Results presented in SPE Paper 134891, Singh et al, 2010.

Sleipner Layer 9 - IP Migration Tool

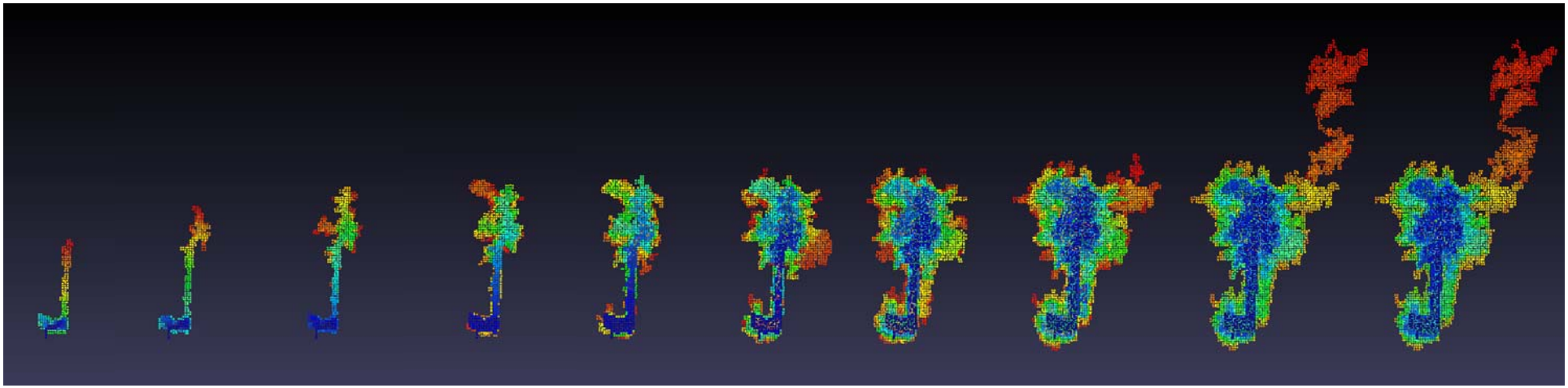


Seismic response

Model Forecast

Grid:
50 x 50 x 5 m
168,000 cells

2001 2002 2004 2006 2008 2010 2012 2014 2016 2030



MPath, Permedia Research

Sleipner Layer 9 - Modeling in Eclipse

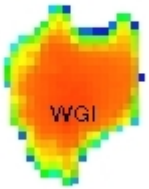
- Objectives:
  - Study of sensitivities (using closure height conditioning)
  - Focus on modeling enhanced gravity segregation
  - Examples from 50x50x5m grid case

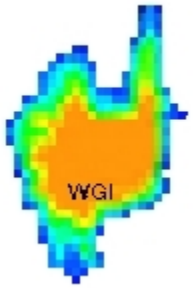
Seismic

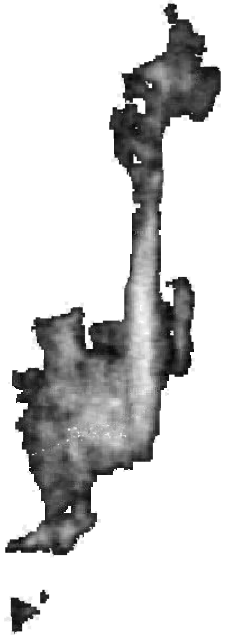
Lab Rel. Perms

Straight Line Rel. perms.

With VE (Lab rel. perms)



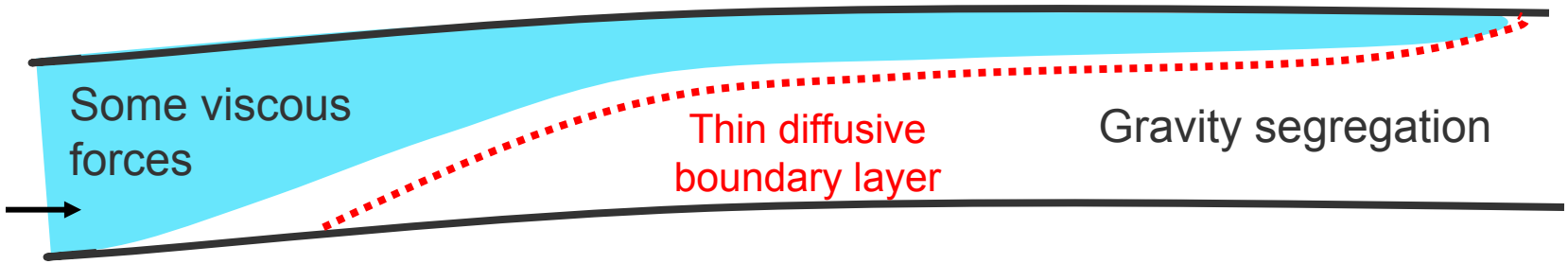




0 *Gas Saturation* 1

Sleipner Modelling: Lessons Learned

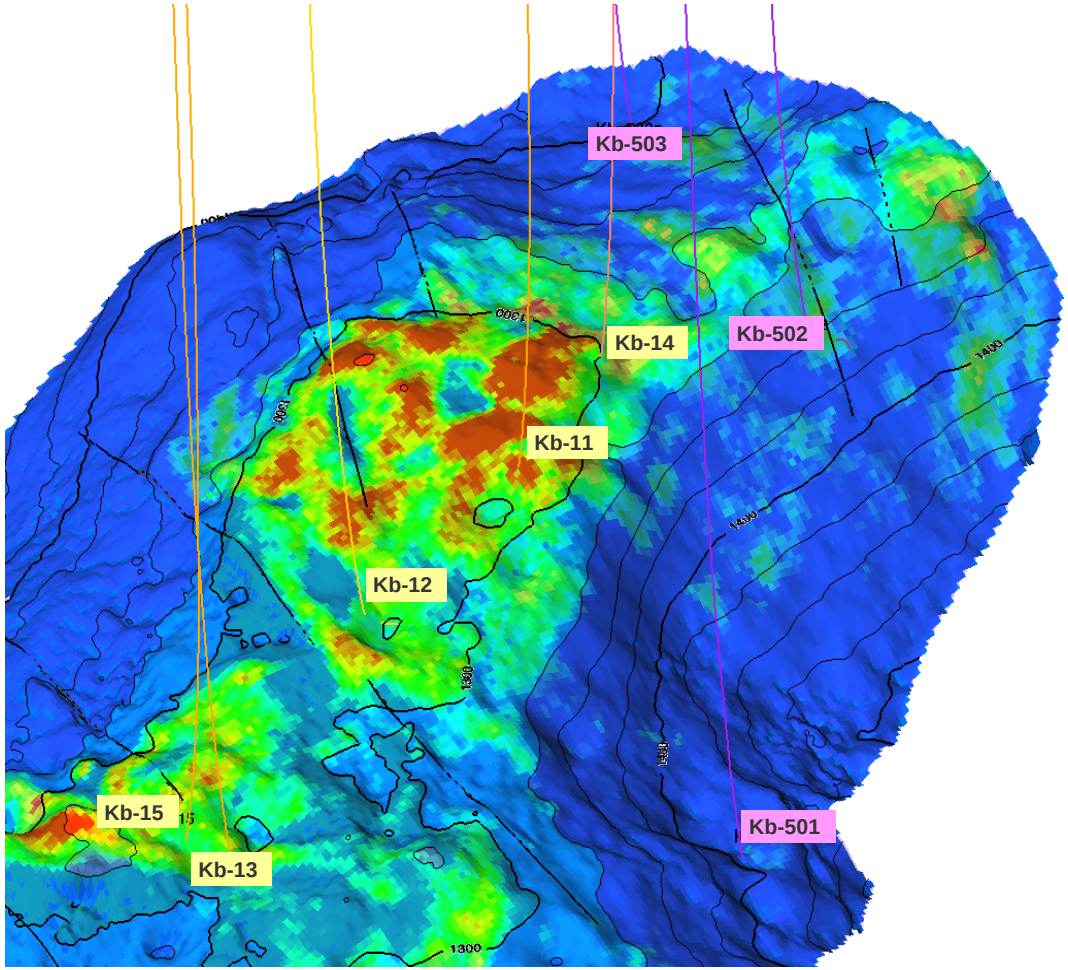
- Detailed analysis of Sleipner Layer 9 (uppermost) reveals strong gravity segregation and plume thinning
  - IP Migration gives a good match to northern plume extension
  - Use of Vertical (gravity) Equilibrium improves Eclipse simulator match
  - Default simulators have too much dispersion and CO_2 dissolution



$$\frac{Viscous}{Capillary} = \frac{u_x \Delta x \mu_o}{k_x (dP_c / dS)} \rightarrow 0 \qquad \frac{Gravity}{Capillary} = \frac{\Delta\rho\, g\, \Delta z}{(dP_c / dS)} \rightarrow 1$$

- Long-term predictions and capacity estimates need to be based on models verified with short-term monitoring data (5 to 15 years)
- Now focusing on multi-layer model and effects of discontinuous (?) shales

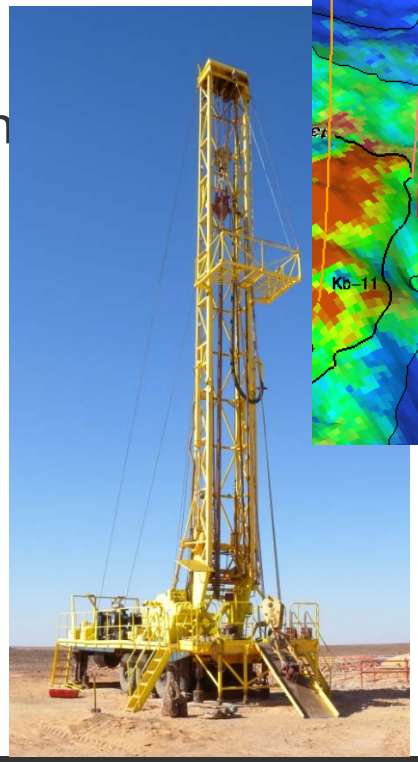
In Salah: An Overview

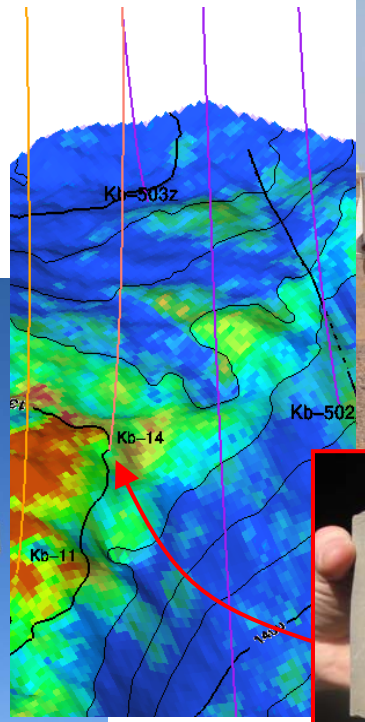


- CO_2 from several fields in the In Salah Gas Development is stored in the aquifer (Carboniferous) at Krechba
- Storage unit is 1880m deep, 20m thick
- 5 gas producers and 3 CO_2 injectors
- 3 long-reach horizontal wells (up to 1800m horizontal sections)
- Initial reservoir conditions:
  - P= 175bars
  - T = 95°C
- Over 3 MT CO_2 have been injected (2004-2009)
- See Ringrose et al 2009, Wright et al 2009.

In Salah: An Overview

- Monitoring Dataset (Mathieson et al., 2010):
  - —Time lapse (4D) Seismic:
    - 1997 (baseline)
    - 2009 (northern area)
  - —Wellhead measurements
    - Monthly wellhead samplin
    - Gas chemistry, Tracers
  - —Satellite InSAR Surveys
  - —Observation wells:
    - 1 Microseismic well
    - 5 shallow aquifer wells
    - CO_2 breakthrough to appraisal well KB-5
  - —Surface Measurements:

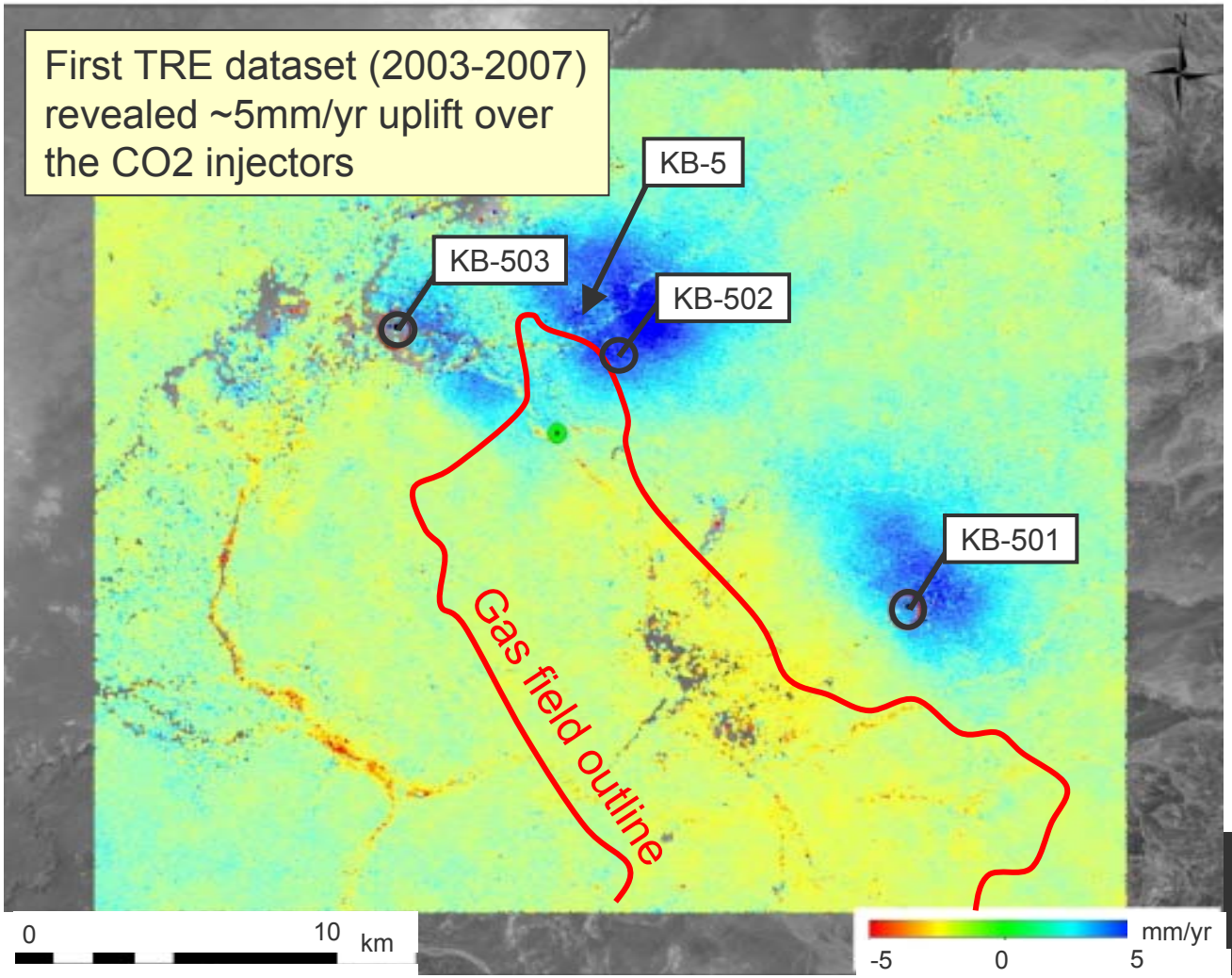




Satellite Monitoring

Pioneering work by TRE and LBNL has demonstrated value of PSInSAR™ to record surface deformation related to subsurface injection:

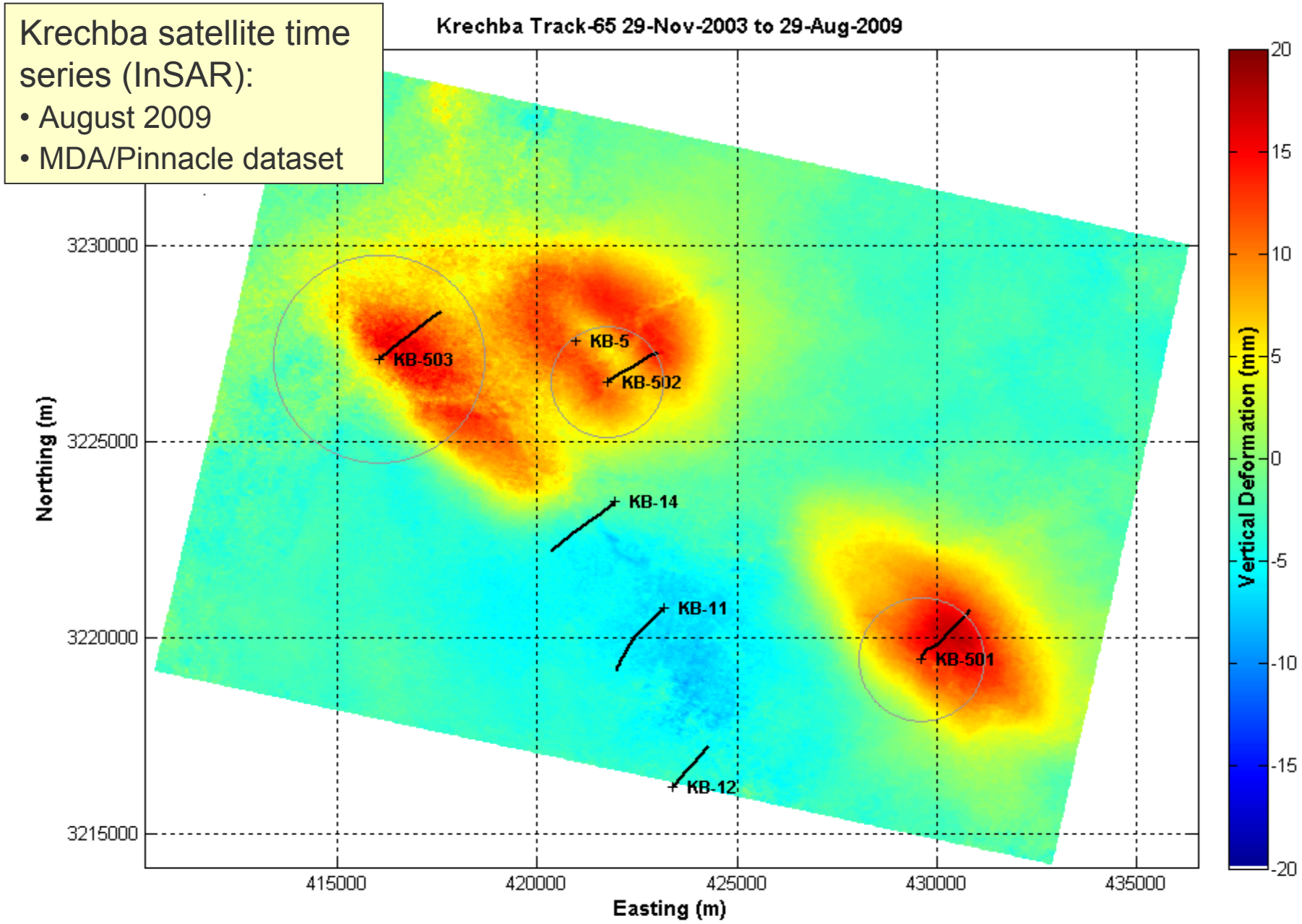
- See Vasco et al., 2008.



Ongoing monthly satellite surveys and surface calibration using tilt meters and DGPS (Pinnacle Technologies)

Krechba satellite time series (InSAR):

- August 2009
- MDA/Pinnacle dataset



Rock Mechanical Response

Reference 2D case - Abacus FE model (Statoil Rock Mechanics group):

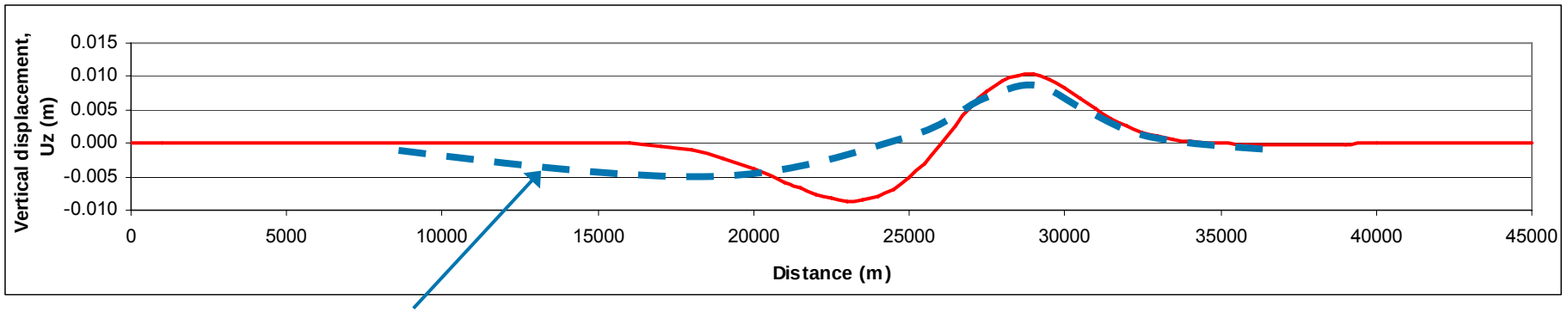
- E (reservoir) = 10 GPa
- E (overburden) = 5 GPa
- Poisson's ratio = 0.2

Vasco et al., 2010, show how a detailed mechanical model is important to correct inversion

Vertical strain (m)

Confirms surface deformation is linear elastic response to subsurface pressure

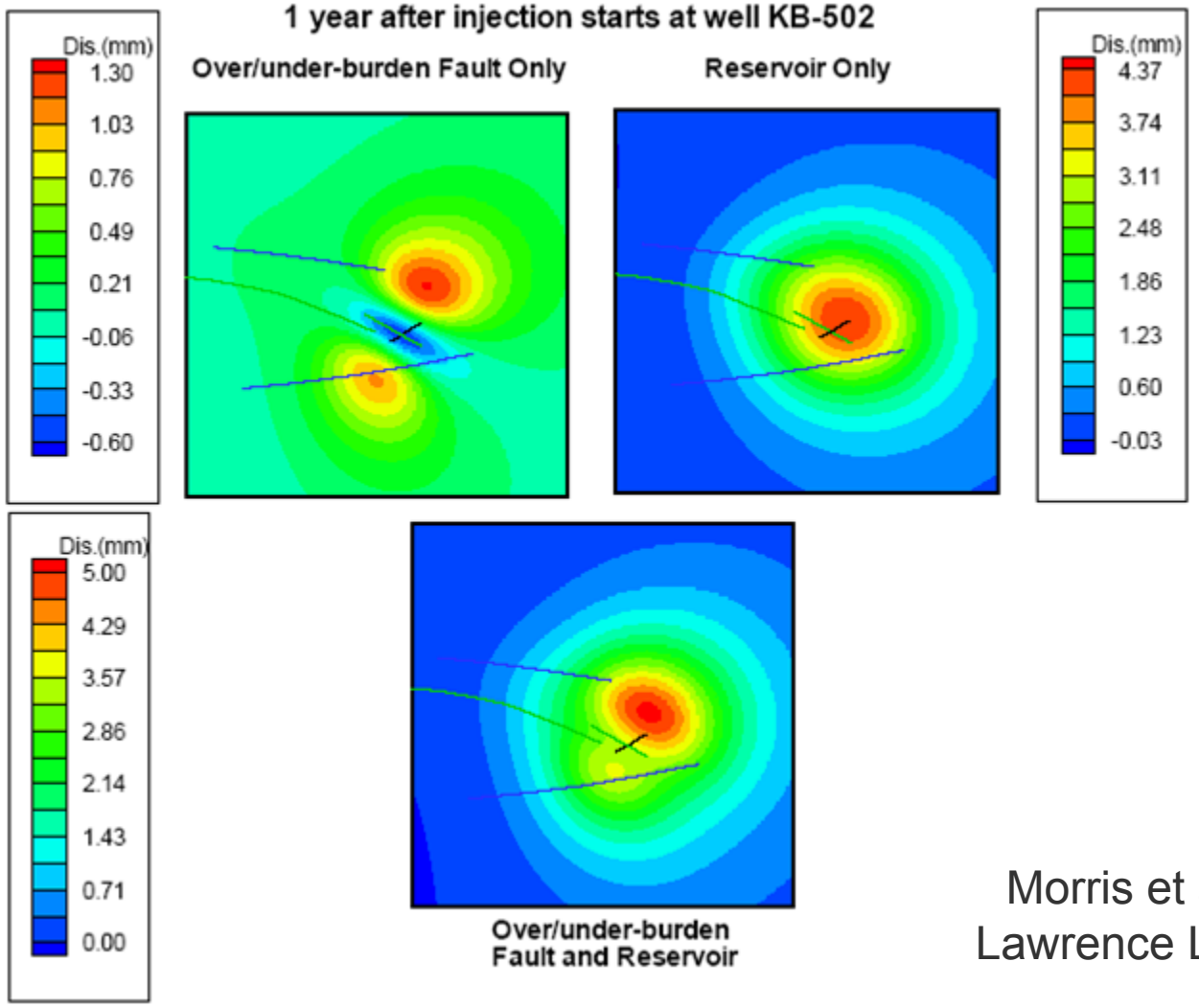
Vertical displacements at model surface



Line through observed deformation from satellite observations

Coupled geomechanical-flow model

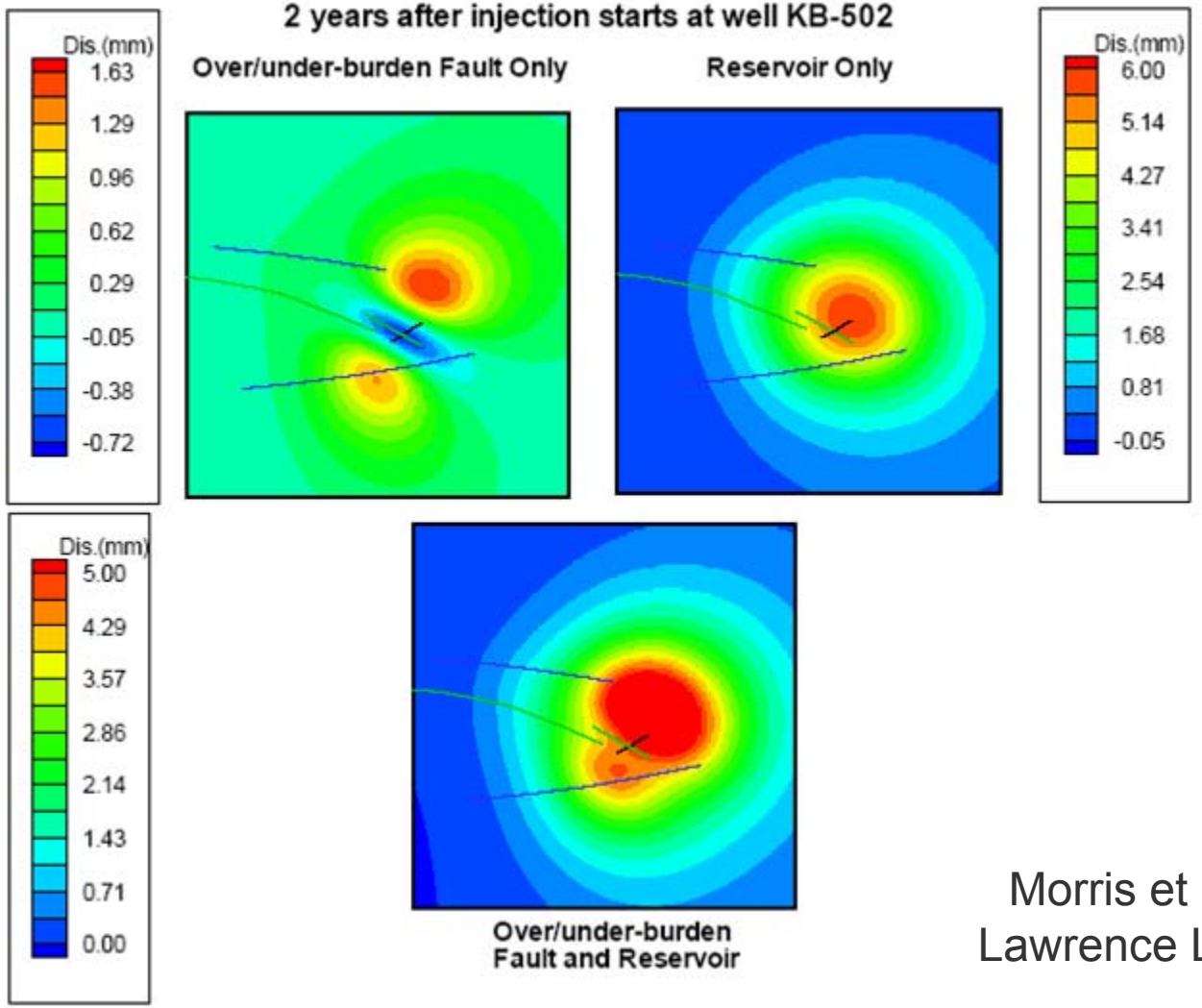
Livermore NUFT Code - 3 Year Analysis



Morris et al. 2010
Lawrence Livermore

Coupled geomechanical-flow model

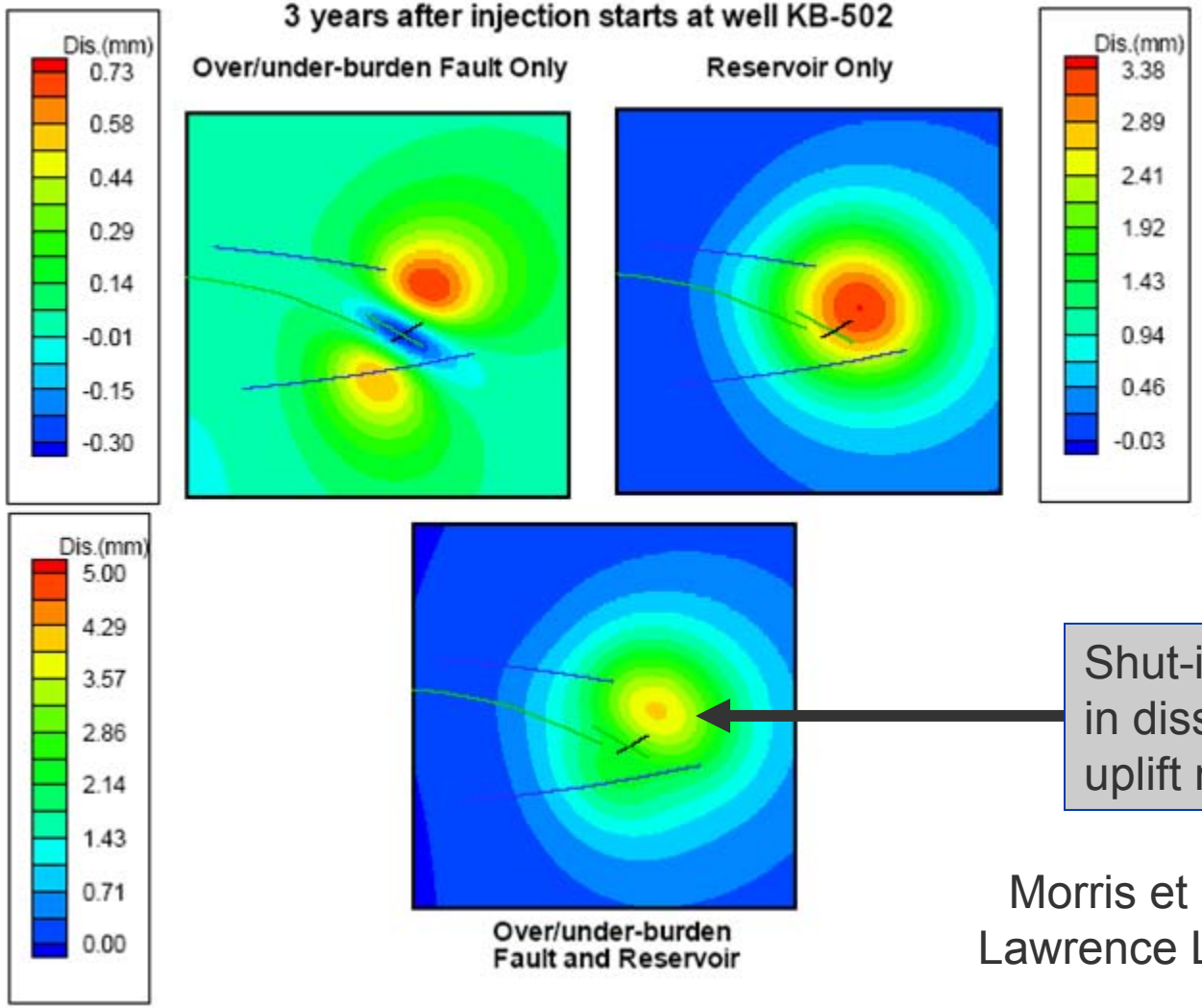
Livermore NUFT Code - 3 Year Analysis



Morris et al. 2010
Lawrence Livermore

Coupled geomechanical-flow model

Livermore NUFT Code - 3 Year Analysis



Shut-in results in dissipation of uplift mound

Morris et al. 2010
Lawrence Livermore

In Salah Modelling: Lessons Learned

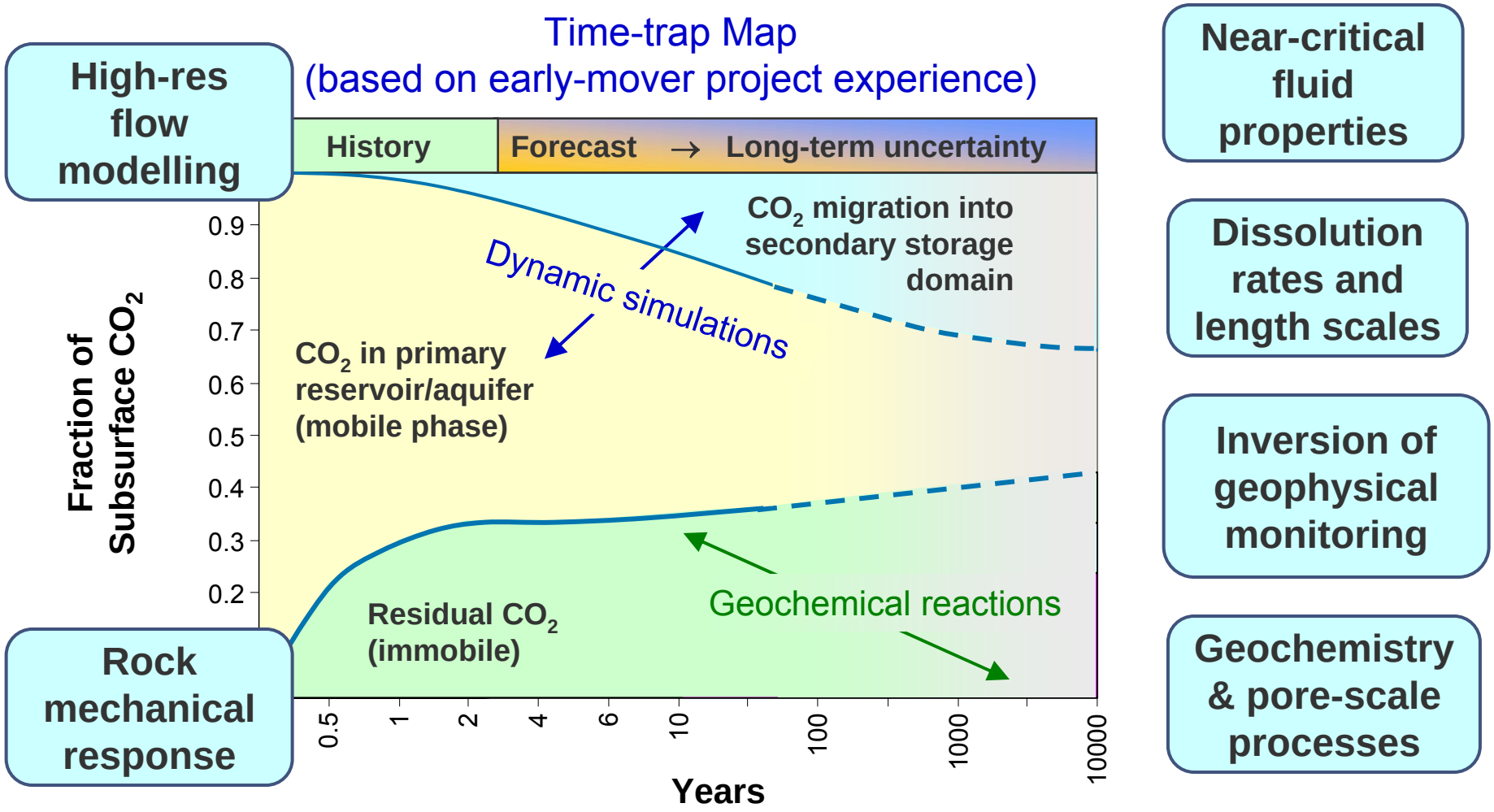
- Pioneering use of satellite InSAR reservoir monitoring technology revealing mm-scale surface deformation
- Important new insights into rock mechanical deformation in response to CO_2 injection (and gas production)
- Surface response is best understood using:
  - detailed geomechanical model
  - combined effects of a fault/fracture and reservoir compartment
- Integration is a key:
  - Space technology, geophysics, rock mechanics, geology, reservoir engineering and well technology

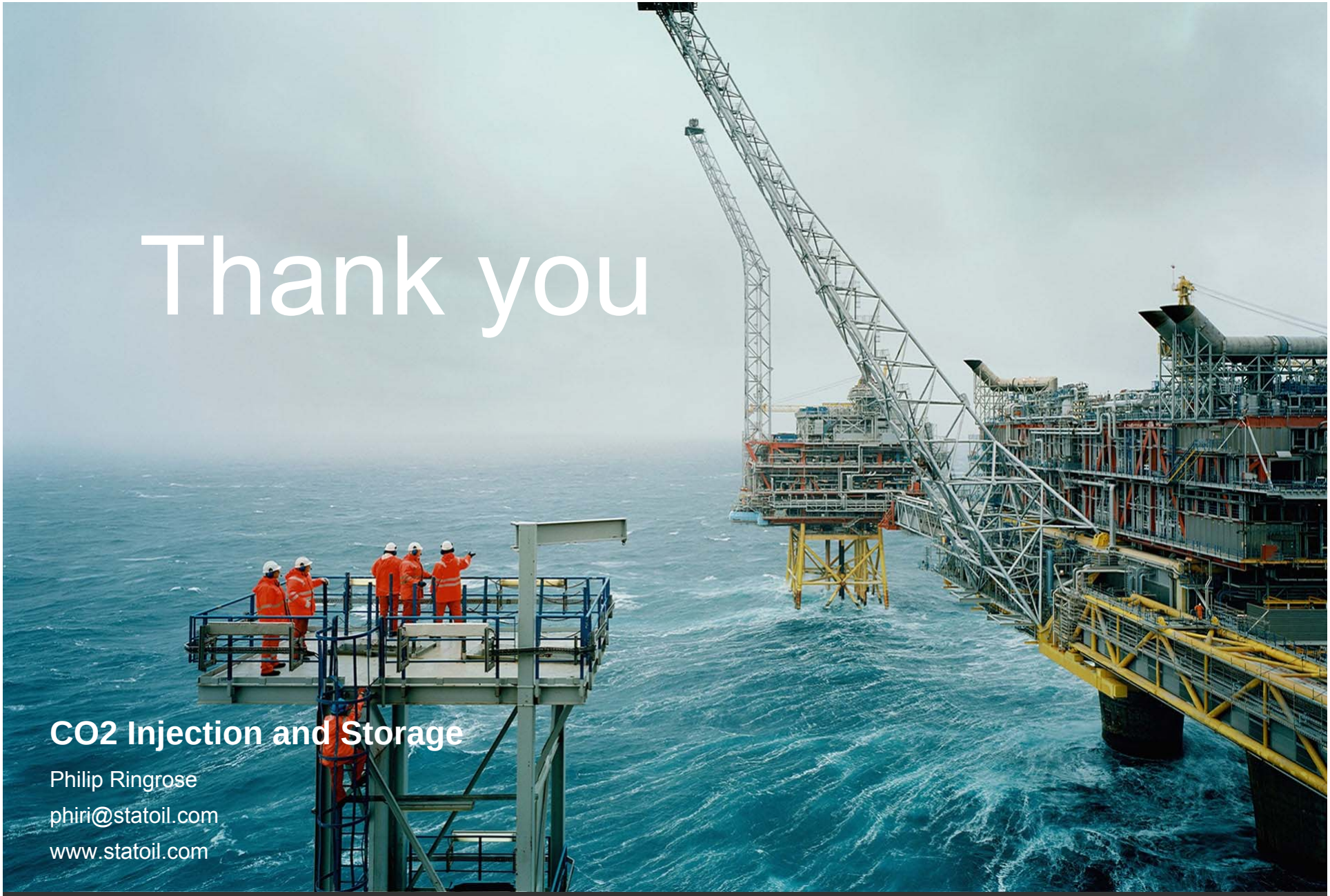
Summary

1. Why model?
   - In order to make engineering decisions
2. What do we need to model?
   - Physics, chemistry and geology
3. What are the elements of modelling?
   - Develop Concepts > Know the Tools
4. Some examples:
   - Learning the important factors & effects

Challenges for Long-term Forecasting

So what are the main challenges?





CO2 Injection and Storage

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