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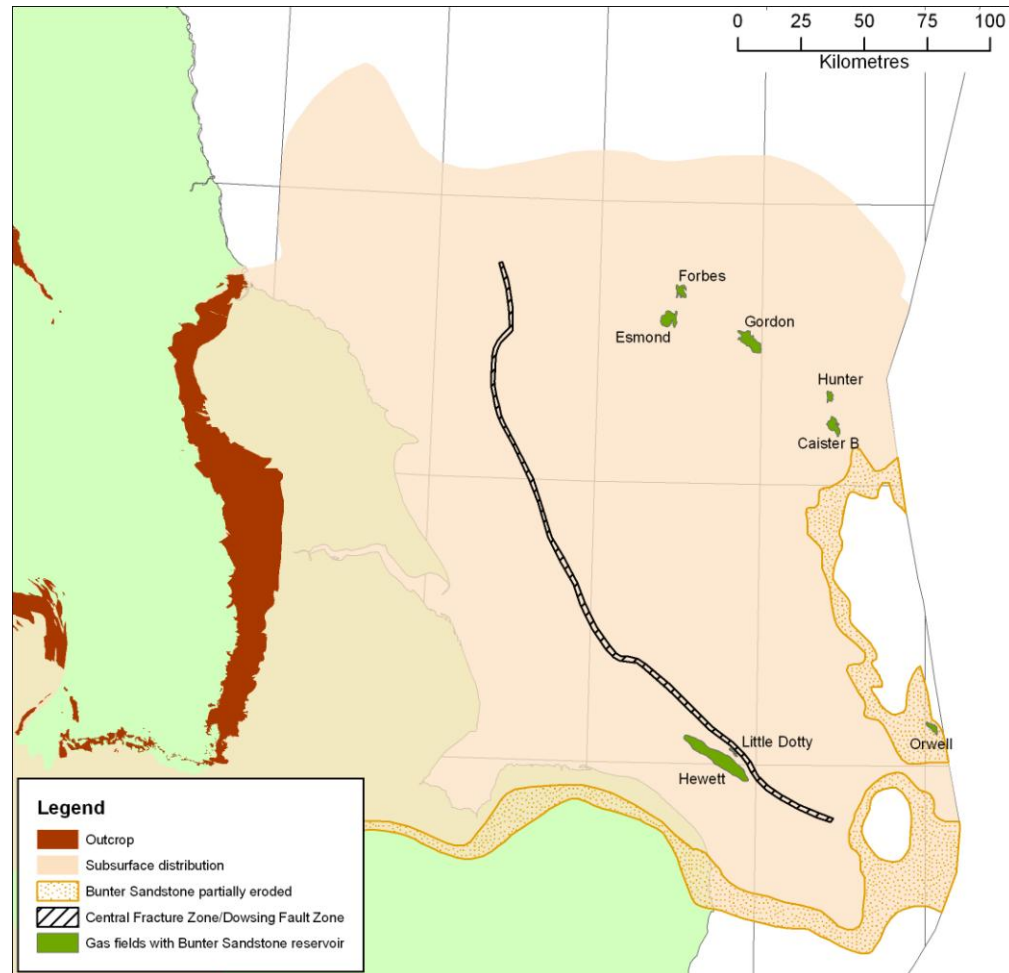
Applied geoscience for our
changing Earth

Modelling CO₂ injection into the Bunter Sandstone, UK sector of the Southern North Sea

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BGS

Where can we store CO₂ in saline water-bearing rocks in the UK?

- Bunter Sandstone Formation perceived as having good CO₂ storage potential
- Good to fair porosity, commonly 15 - 20%
- Permeability of the order of 100 mD
- Up to >350m (typically 200m) thick
- Typically 1 to 3 km deep in SNS east of Dowsing Fault Zone
- Pore fluid commonly brine with salinity up to about 300,000 ppm
- 8 gas fields in UK sector Bunter
- Normally pressured



Seals above and below the Bunter Sandstone

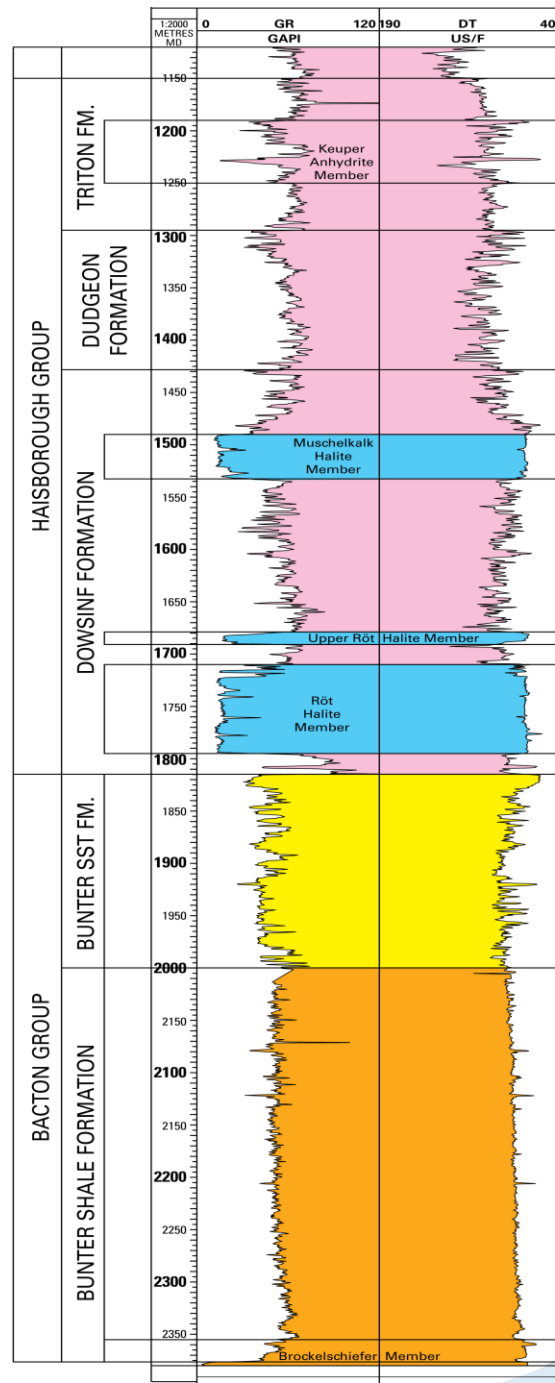
Overlain by Haisborough Group

- mudstones with thick halites

Underlain by Bunter Shale

- mudstones, with sandy interbeds towards UK coast (Amethyst Member)

Near its eastern and southern margins, the Haisborough Group is cut out at Base Cretaceous unconformity, and the Bunter Sandstone is sealed by the Early Cretaceous Speeton Clay

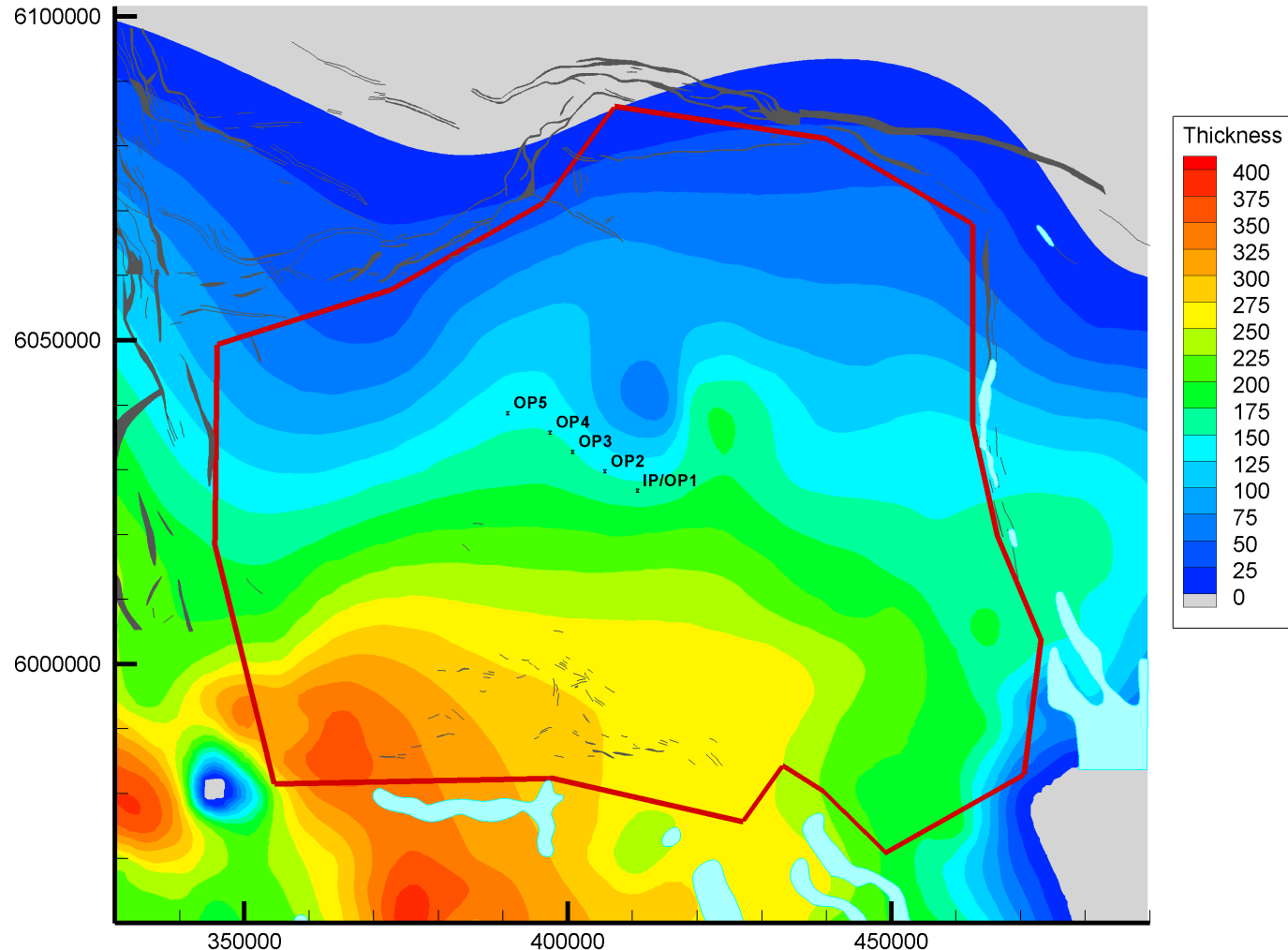


Compartmentalisation in the Bunter Sandstone Formation

- Could vary across UK SNS
- Evidence of pressure communication between Hewett and Little Dotty fields (Cooke-Yarborough & Smith 2003)
 - Crests 5 km apart, separated by North Hewett Fault
- Some evidence of post-gas charge halite cementation in Caister B field (Ritchie & Pratsides 1993) and elsewhere e.g. Esmond.
 - Reduces permeability where present
 - Could affect pressure communication within the aquifer in NE?

The model

- Based on depth and isopach map of Bunter Sst
- 130 km E-W, 116 km N-S
- 122 x 94 x 10 elements 500m – 5000m in size
- No internal permeability barriers
- Pore volume 584 km³



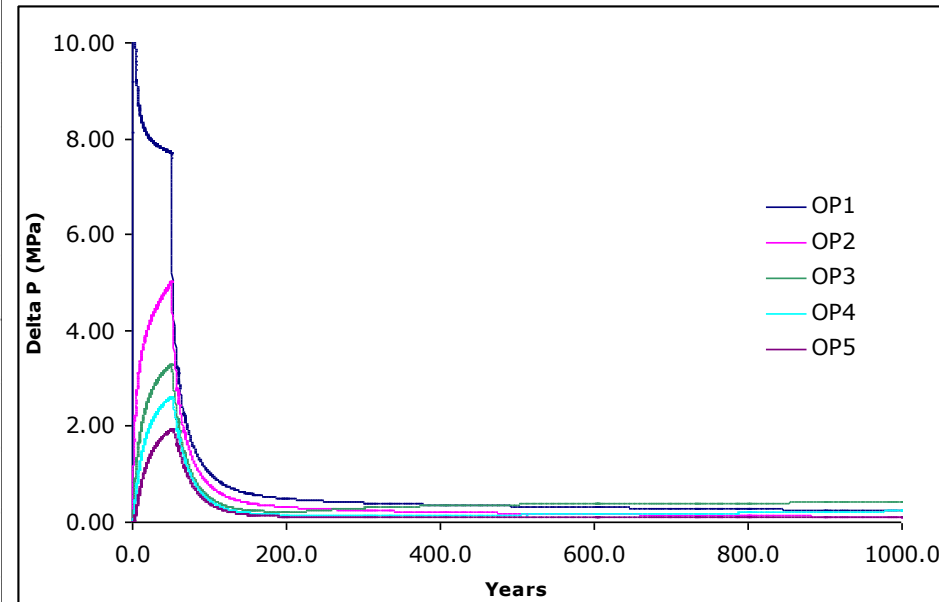
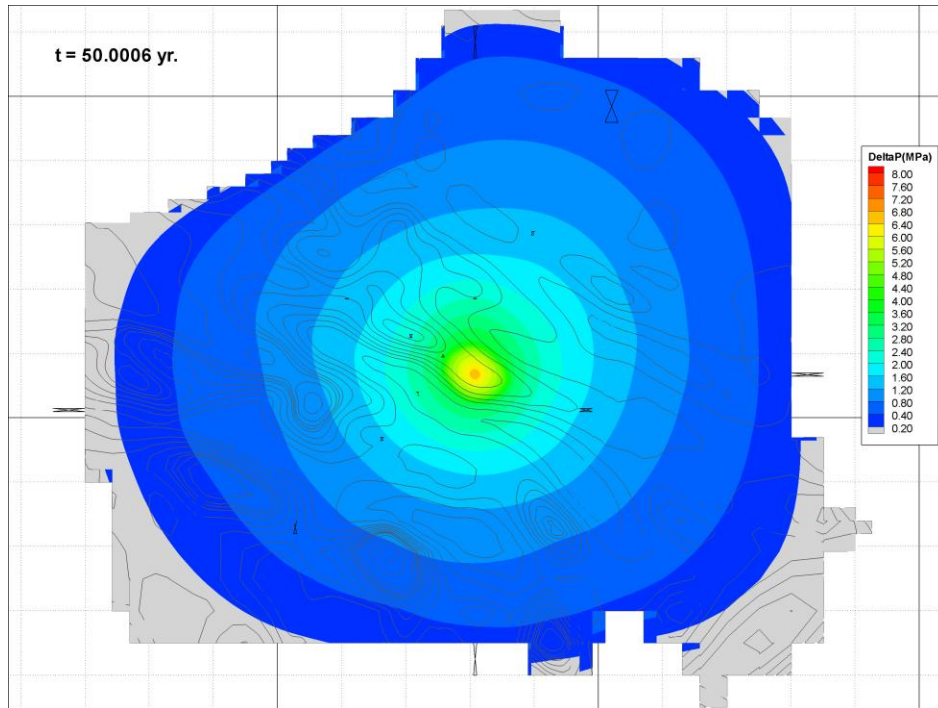
Base case model

- Reservoir permeability: 100 mD
- Reservoir porosity (θ): 20%
- Reservoir pore volume: 584 km³
- Ratio of vertical to horizontal permeability (k_v/k_h): 1
- Brine salinity: 130,000 ppm NaCl
- Lateral and underlying boundaries impermeable. 50 m of caprock $k = 10^{-19}$ m² overlies the reservoir
- Thermal gradient: $dT/dz = 35^\circ\text{C}/\text{km}$
- Reservoir properties uniform throughout the model
- 10 Mt CO₂ p.a. injected for 50 years through 1 well
- Model allowed to evolve to 1000 years

Parameters varied

- Permeability of reservoir boundaries
- Caprock thickness
- Reservoir permeability
- Reservoir porosity
- $K_v:K_h$
- Injection rate
- Number of injection points

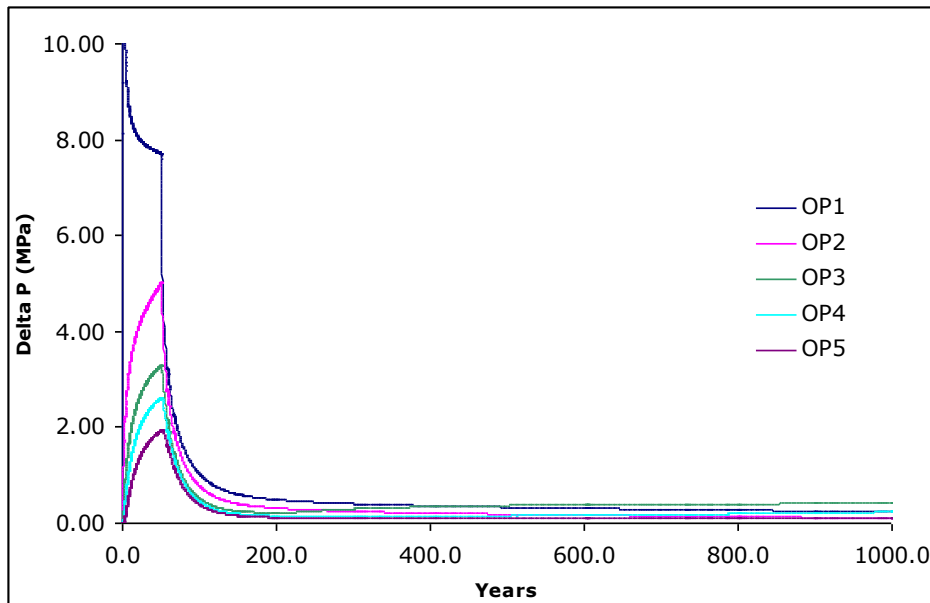
Base case model



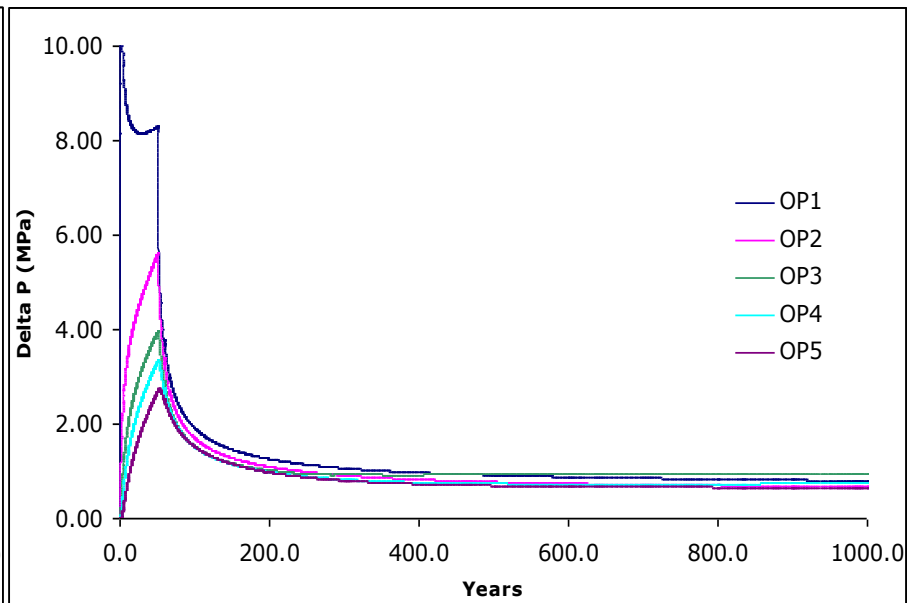
Pressure distribution at 50 years

Pressure evolution

If all boundaries impermeable

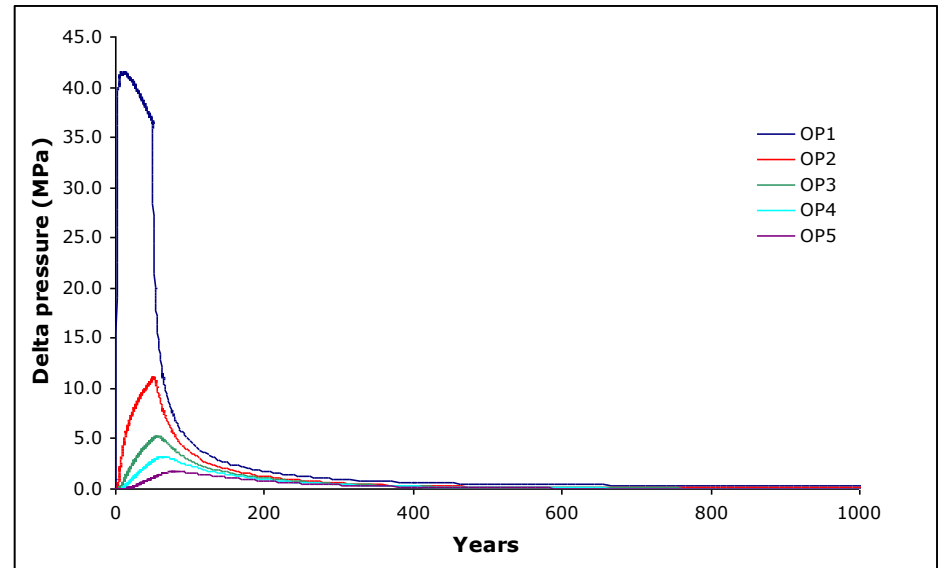
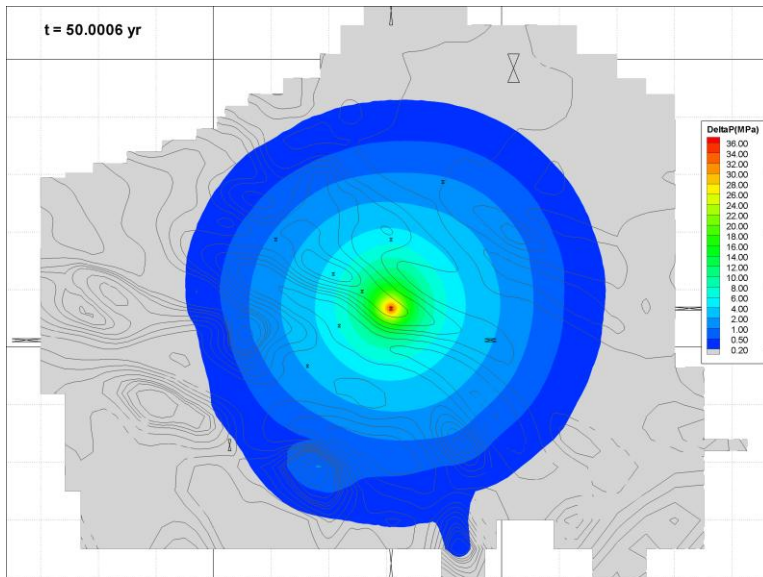


Pressure evolution, base case



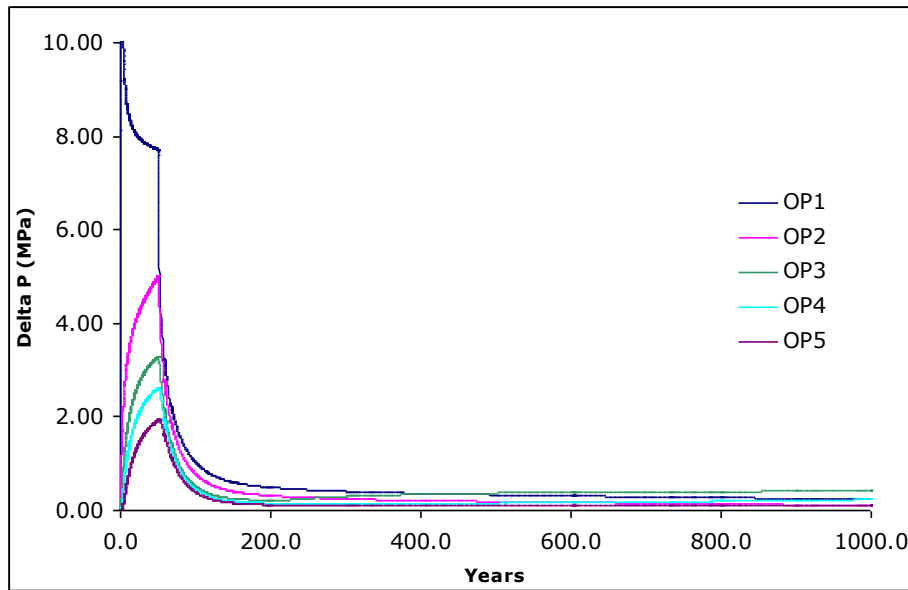
Pressure evolution
impermeable cap rock

Reducing k to 10 mD

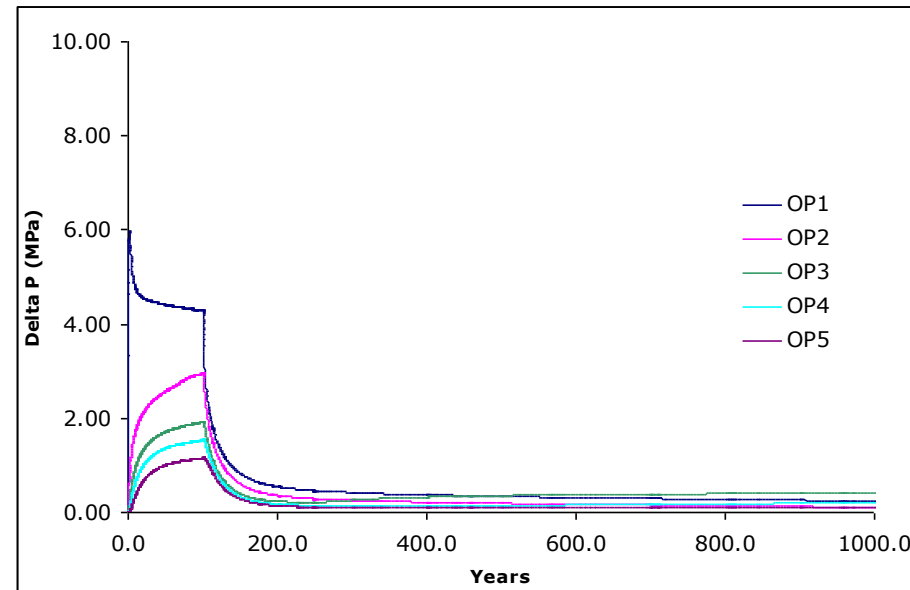


k is a key factor – pressure increase >40 MPa near well.
Need to adjust injection rate to suit permeability

Halve injection rate and double injection period

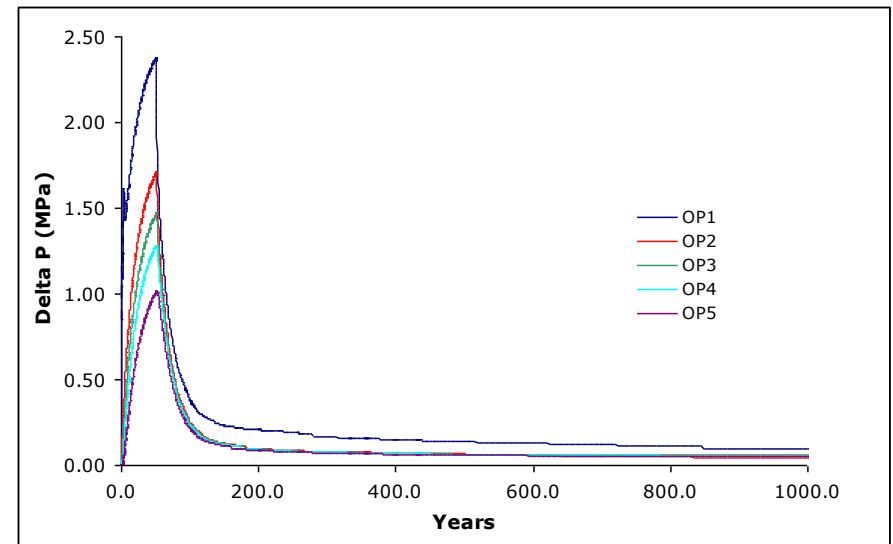
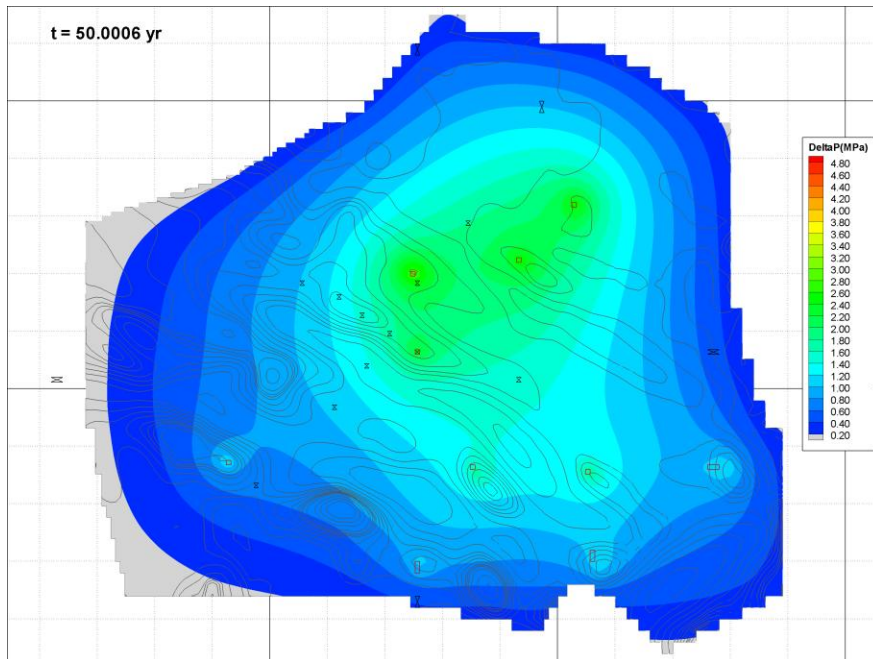


Base case pressure evolution



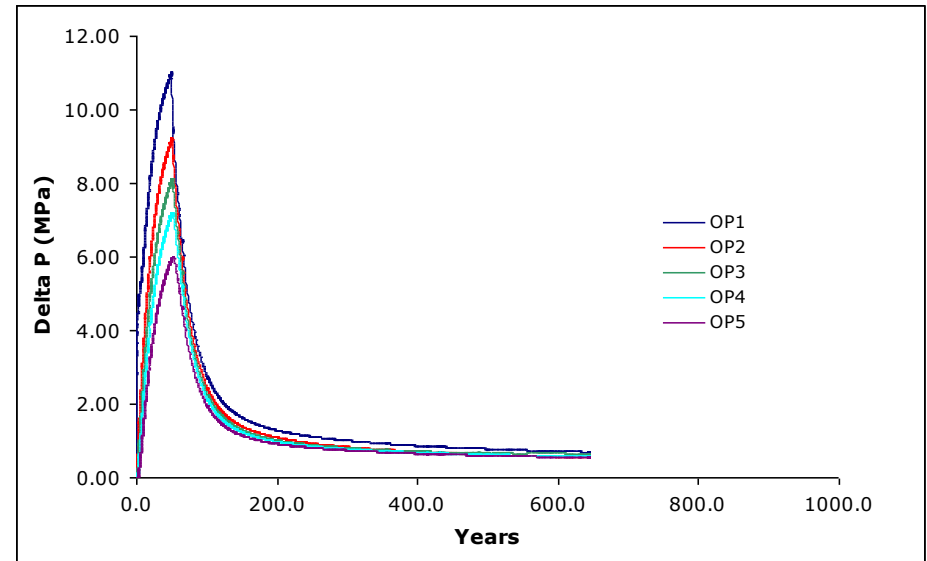
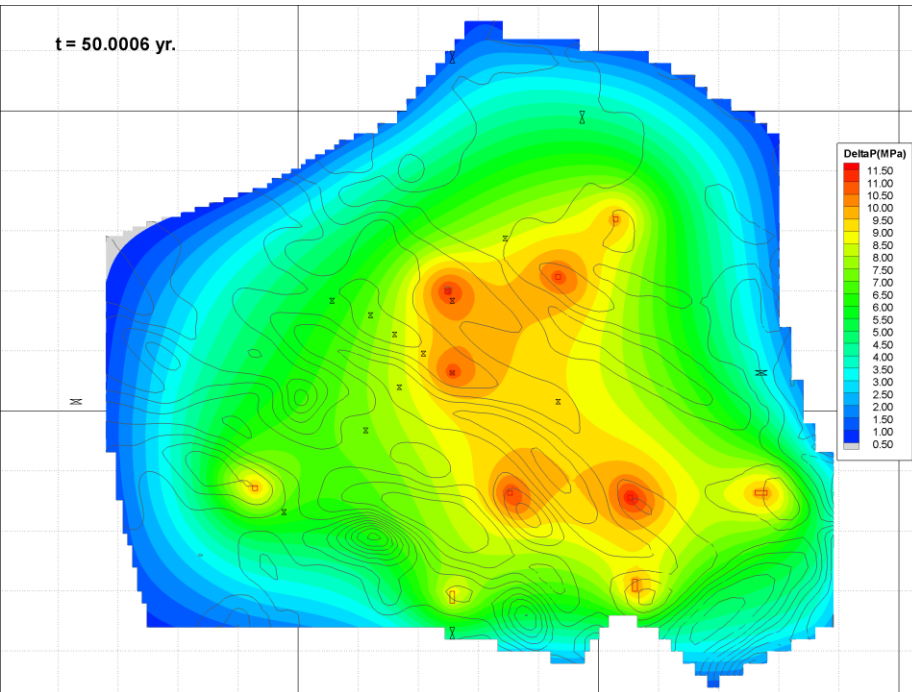
Pressure evolution 100 years injection at 5 Mt CO₂ p.a.

10 injection points, 1 Mt CO₂ p.a. per well for 50 years



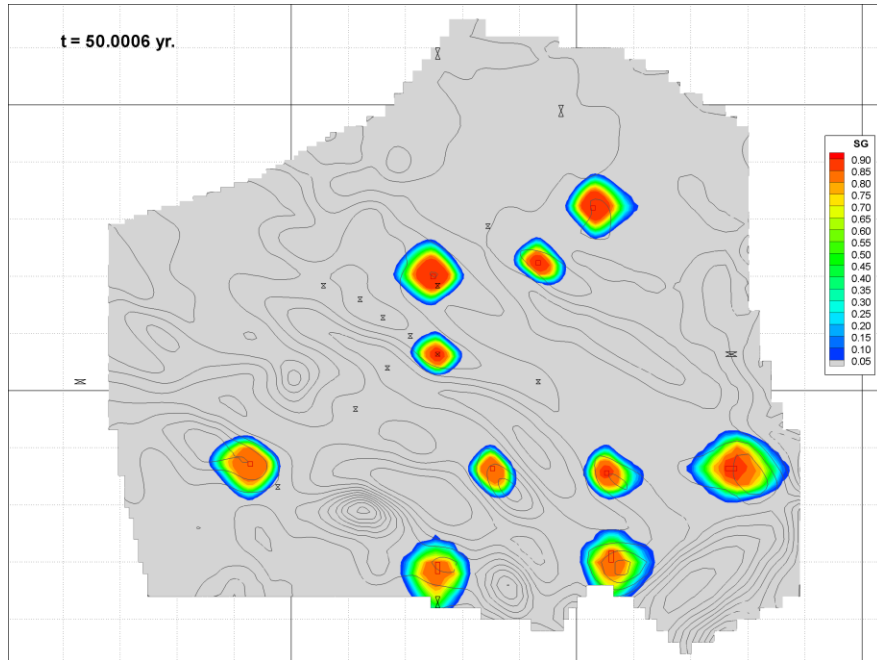
Near-well pressure increase greatly reduced, more even pressure distribution in injection period

92 Mt CO₂ p.a. through ten wells

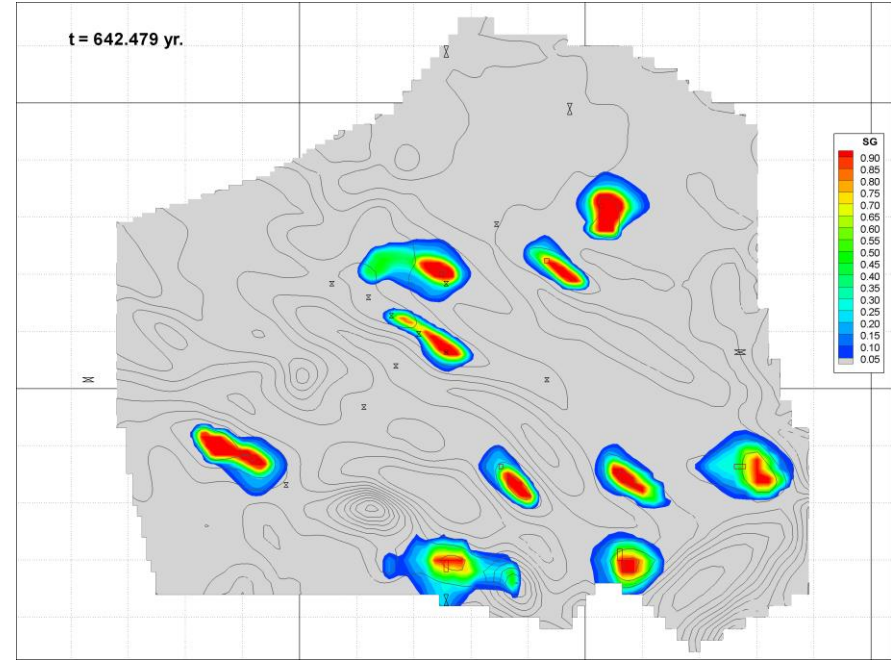


More even pressure distribution during injection period, delta p slightly exceeds 10 MPa near wells

92 Mt CO₂ p.a. through ten wells



CO₂ distribution after 50 years



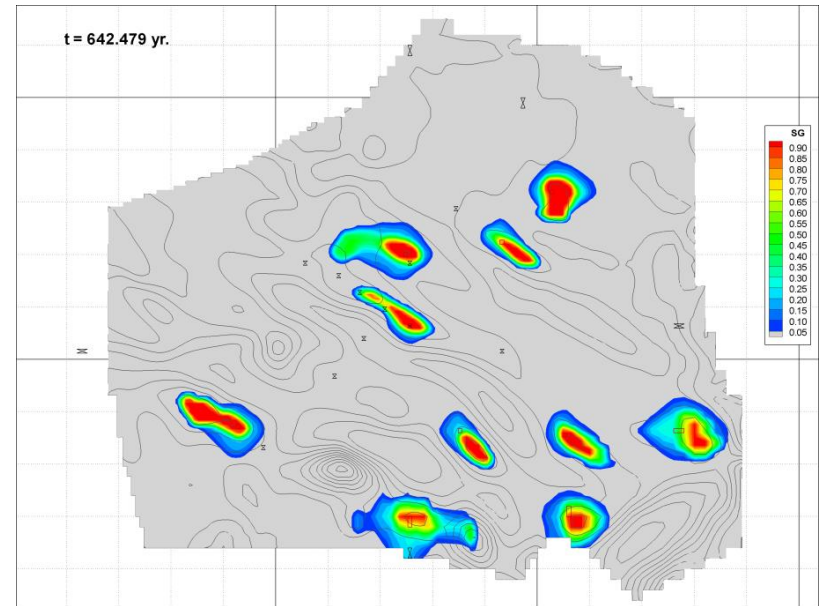
CO₂ distribution after 642 years

Conclusions

- The model is only a very crude representation of the Bunter Sandstone Formation - major assumptions include permeability of cap rock, no-flow boundaries around model and absence of permeability barriers within model
- About 2000 Mt CO₂ can be injected into the model without exceeding the 10 MPa pore fluid pressure increase threshold if all the boundaries of the model are made impermeable.
- About 4500 Mt CO₂ can be injected into the model if the cap rock is assigned a possibly realistic permeability
 - (but note Rot and Muschelkalk halites are present within the cap rock over much of the modelled area)

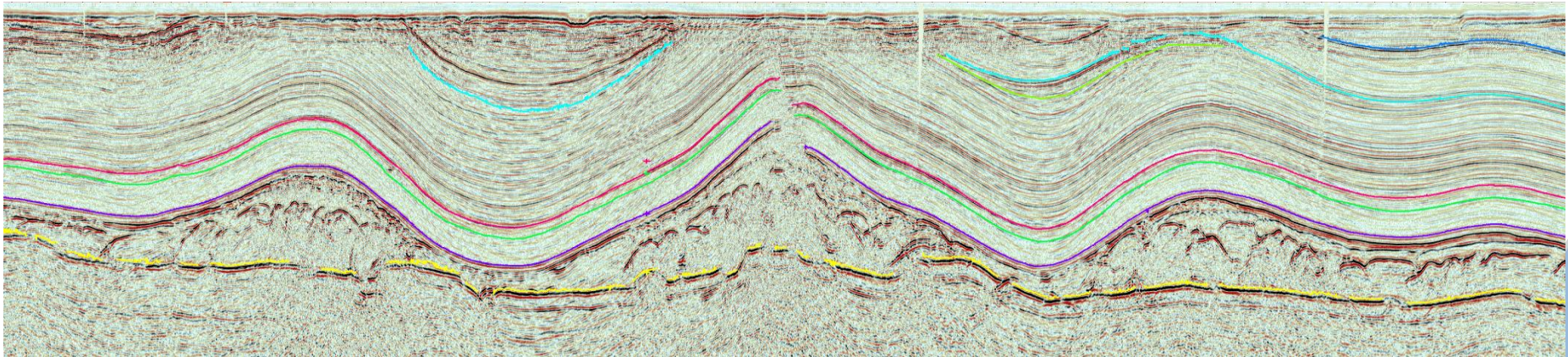
Conclusions

- The injected CO₂ fills a maximum of about 1% of pore space in the target formation in the cases considered
- Pore fluid pressure rise is a greater constraint on CO₂ storage capacity than physical containment within the storage formation
 - Probably the case for most well-confined formations
 - Possibly not the case for Utsira-like formations, which may be well connected less tortuously to the sea bed?
 - Reservoir permeability / injection rate are key factors influencing pore fluid pressure rise in our model



And finally.....

- The model neglects containment risks (faults) not only in the CO₂ footprint but also within the pressure footprint, where there is the potential for brine with a salinity of ~300,000 ppm to leak to the sea bed



Seismic data courtesy of Schlumberger WesternGeco