Assessment of Storage Injection

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SCCS

Outline

- Introduction
  - Issues
- Case Studies
  - Bunter dome
  - Channel sands
  - Captain aquifer
- Conclusions

Issues to Consider

- Want to ensure safe storage, avoid
  - high pressure build-up
  - migration of CO_2 out of the storage complex

- We need to have good injectivity
  - injection rate/unit rise in pressure
    - m3/day/Mpa
  - need high permeability

Issues to Consider

- But, uncertainty about aquifer structure and properties
  - require modelling and simulation
  - cover a range of possibilities

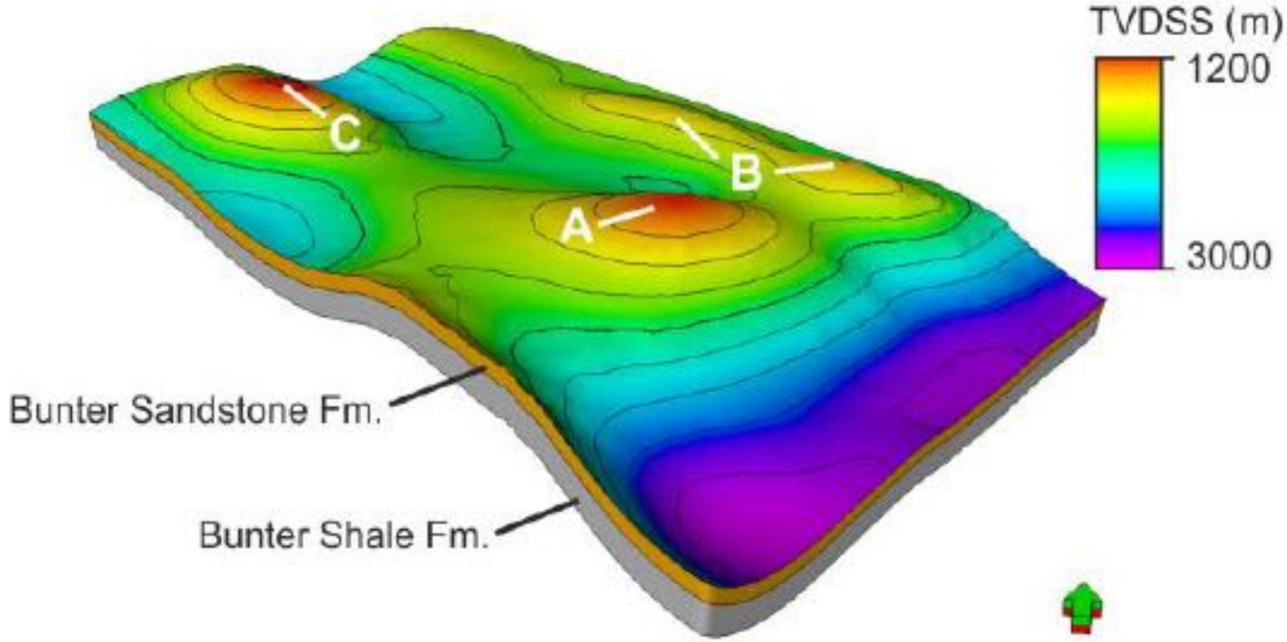
- Knowledge gained from modelling
  - plans for initial injection strategy
  - ID targets for data gathering

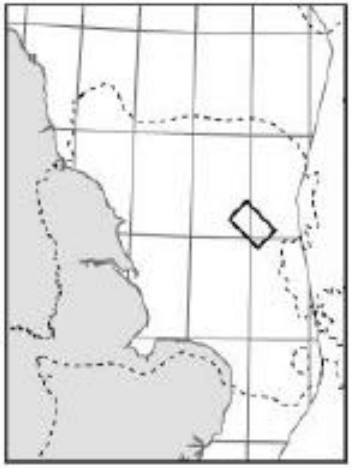
Bunter Dome Study

Energy Technologies Institute
UK Storage Appraisal Project
(ETI UK SAP)
In collaboration with BGS, Keyworth

Bunter Model

- Bunter Formation, S. North Sea





Williams et al, IJGGC, 2013

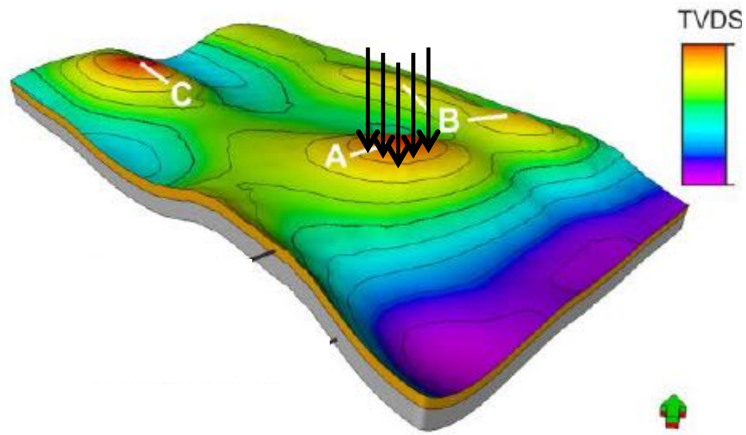
Issues in Bunter study

- Uncertainties
  - extent of the aquifer
  - continuity of a low-perm cemented layer
  - level of heterogeneity
  - will CO_2 migrate out of the dome?

- Injection strategy
  - location of wells
    - distance from crest
  - injection rate

Simulations Performed

- Focused on Dome A
  - 10 wells , controlled initially by rate (2 Mt/yr/well)
  - constrained by maximum pressure limit at well
  - and maximum pressure rise at crest of dome
  - also constrained by migration across spill point



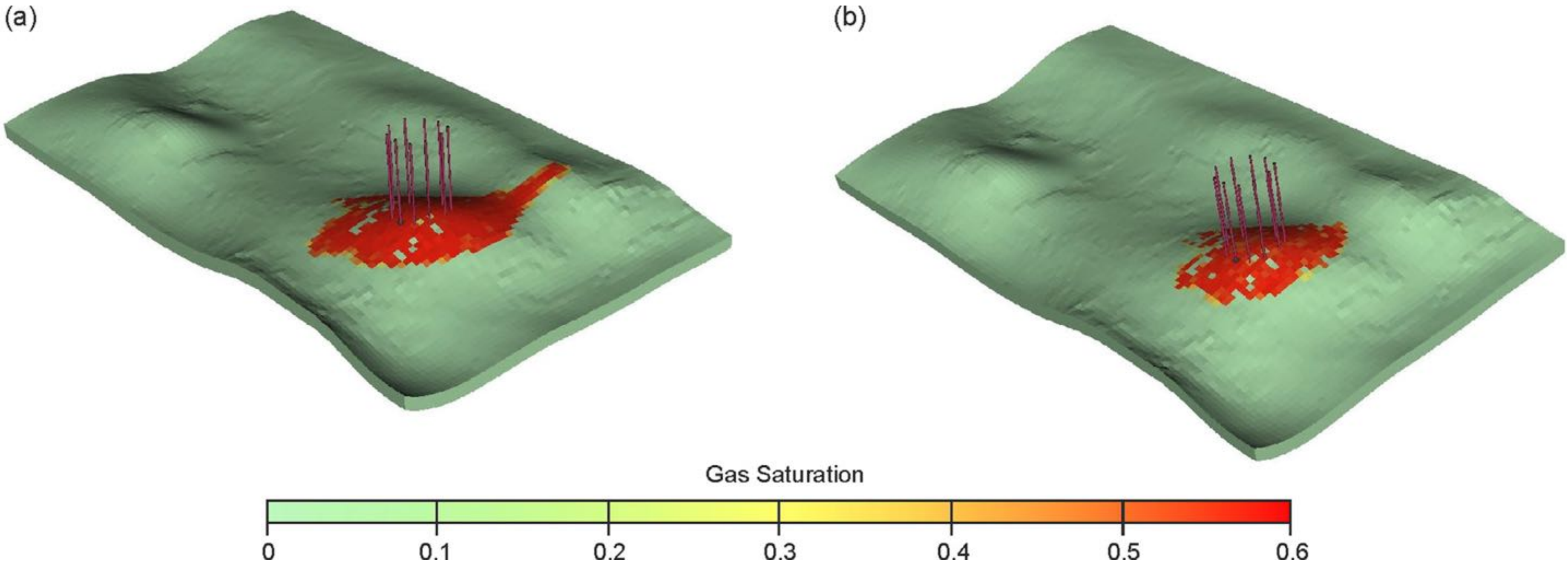
Results

- Examined of dome storage efficiency, E_d
  - volume of CO_2 stored in dome/volume of dome
- Base-case, E_d ~ 19%
  - lower value for limited extent of the aquifer
  - higher value for
    - open aquifer
    - model with no cemented layer
    - homogeneous model

Example Results

a) Cemented layer
- CO_2 migrates underneath

b) No cemented layer
- CO_2 rises due to buoyancy



Discussion

- If injection rate is high
  - pressure will build-up and well may shut in
  - or, CO_2 may migrate through the spill point
- If injection rate is low
  - allows for buoyant rise and higher storage capacity
- If injection wells are placed far from crest
  - risk of migration across spill point
  - but, could be risk of fracturing at crest

Channelised Formations

Funded by The Crown Estate
in collaboration with Durham University

Channel Sand Formations

- Two types of formation
  - Turbidites
  - Fluvial
  - Both characterised by channel sands in a low-perm background

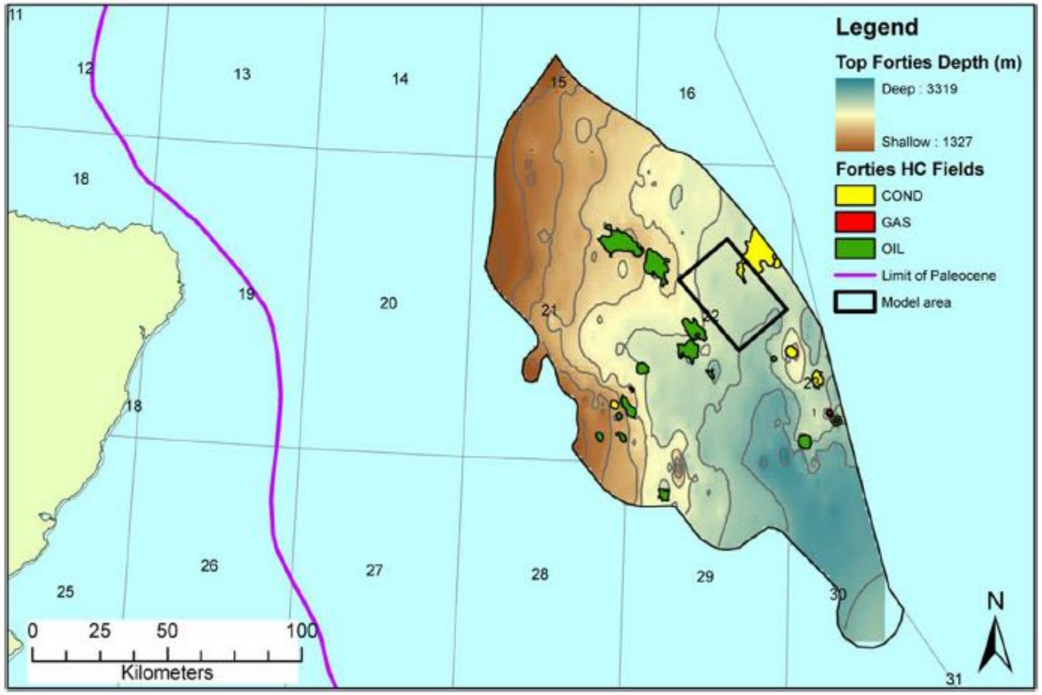
http://en.wikipedia.org/wiki/Braided_river

Issues in Channel Sands

- Connectivity of the channels
  - good connectivity could lead to long-range migration
- Volume of sandstone connected to the injector
  - injection into isolated channels will cause pressure build-up
  - risk of fracturing

Forties Aquifer

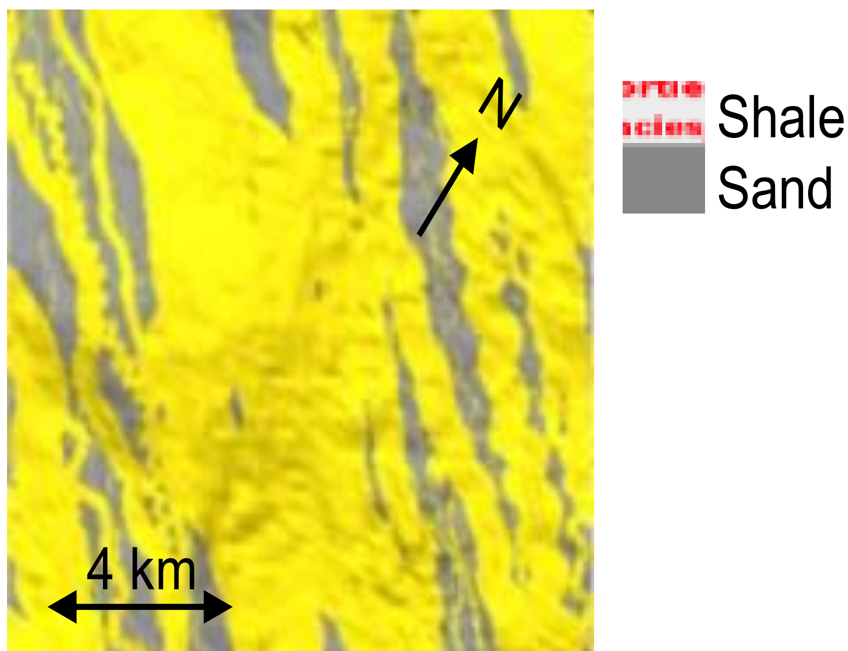
- Model of Forties Formation (Aquifer)
  - model created for ETI UK SAP project
  - turbidite depositional system



From Goater et al, 2013

Turbidite Model Properties

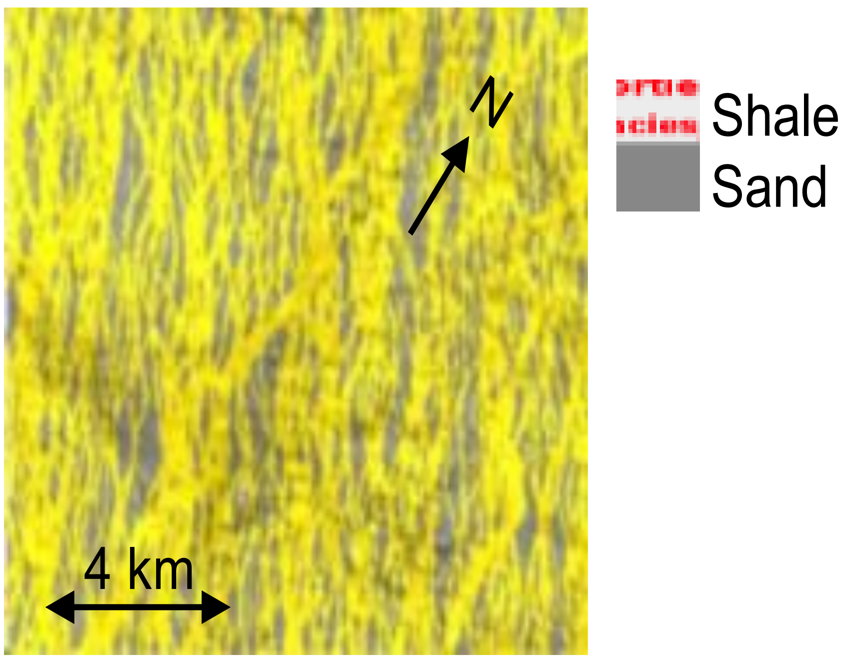
- Sand:shale ratio: 80:20
- Average channel width: 500 m
- Average channel thickness: 8 m

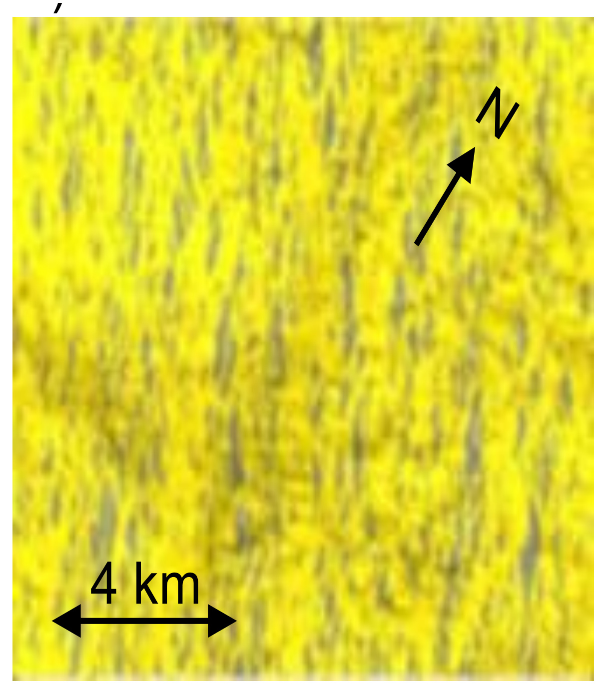


Fluvial Models

- sand:shale 65:35

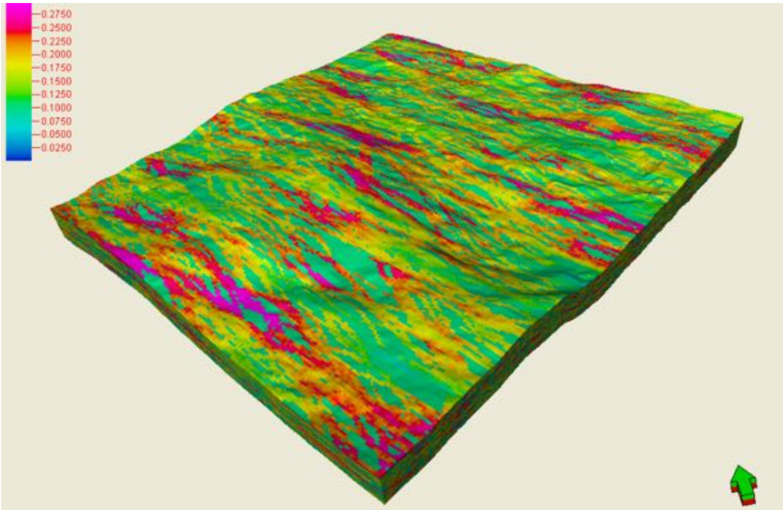
sand:shale 80:20

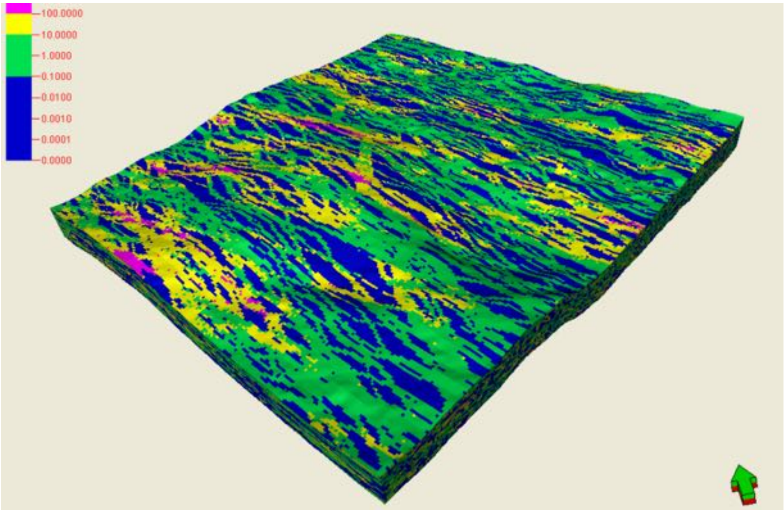




Example of Poro-Perm Properties

- Porosity
- Permeability





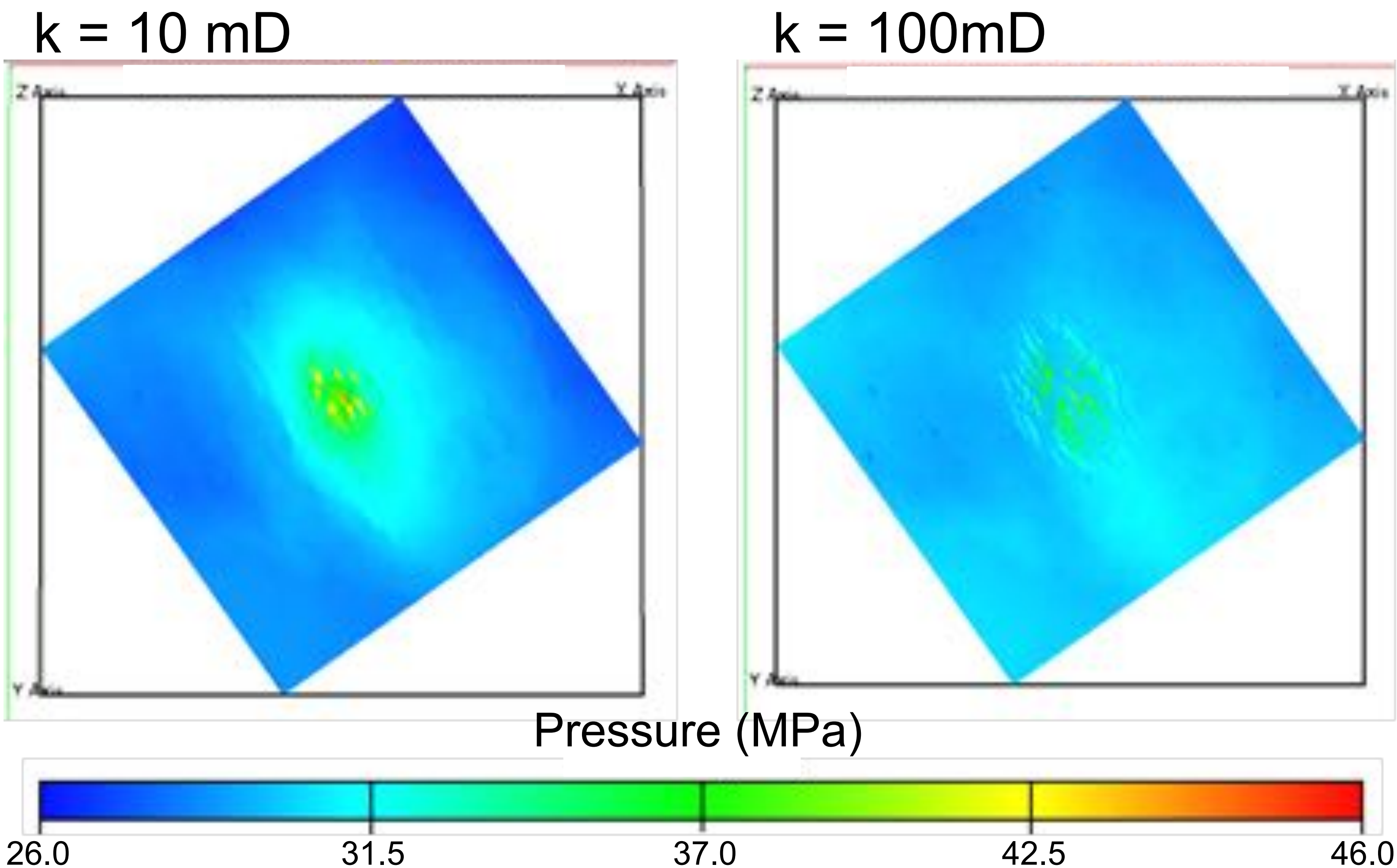
Model Properties

- Total model size: 13 km x 12.6 km x 170 m
- Average sandstone permeability
  - 3 cases: 10 mD, 100 mD, and 1000 mD
- Average sandstone porosity
  - 0.2 for all cases
- Properties of the shale
  - Perm = 10^{-5} mD
  - Poro = 0.1

Numerical Simulations

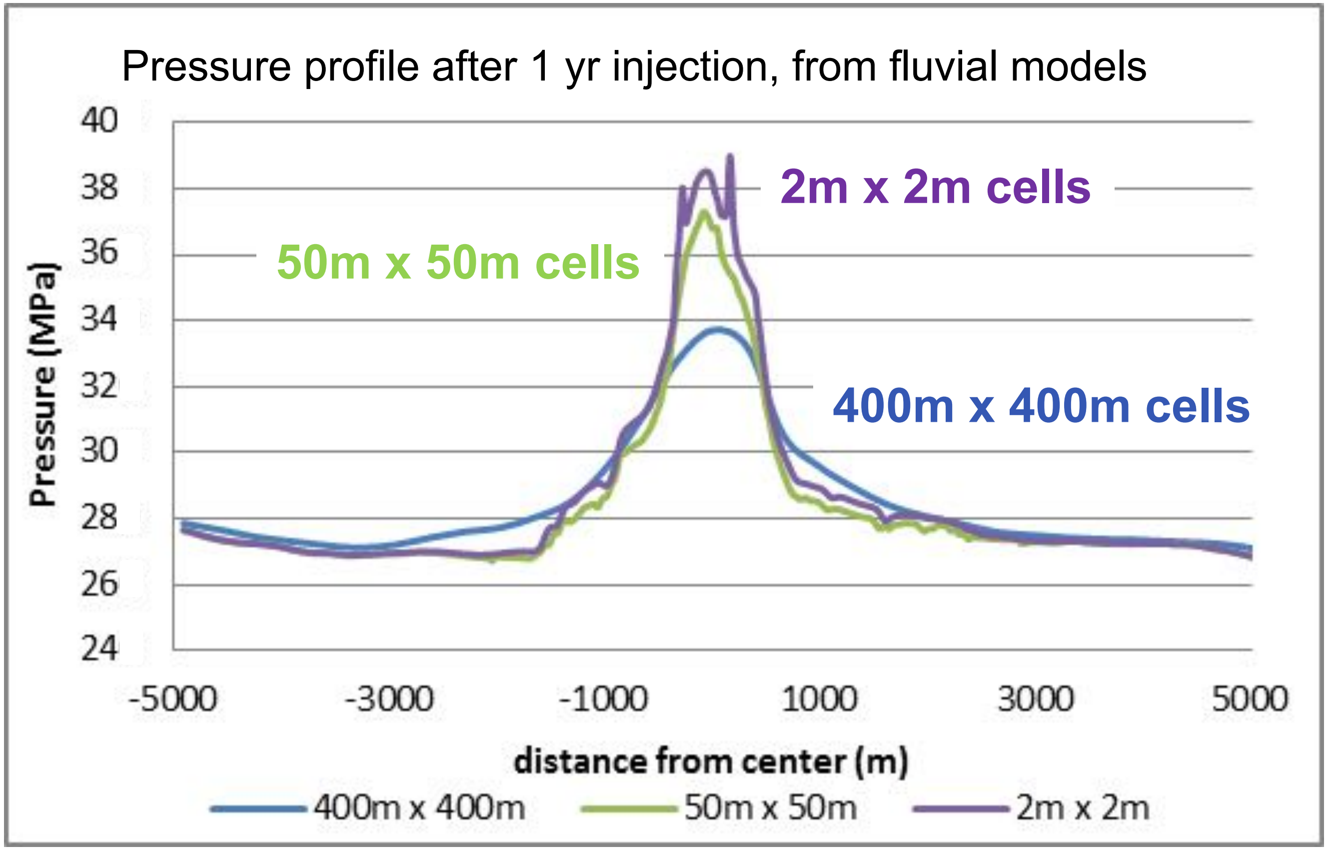
- CO_2 injected through 4 wells in centre of model – perforated through whole thickness
- Injection rate: 0.5 Mt/yr/well
  - max pressure = 400 bar (40 Mpa)
- Total injection time: 20 years

Pressure Buildup



Pressure Profiles

- The coarse grid does not resolve the pressure increase



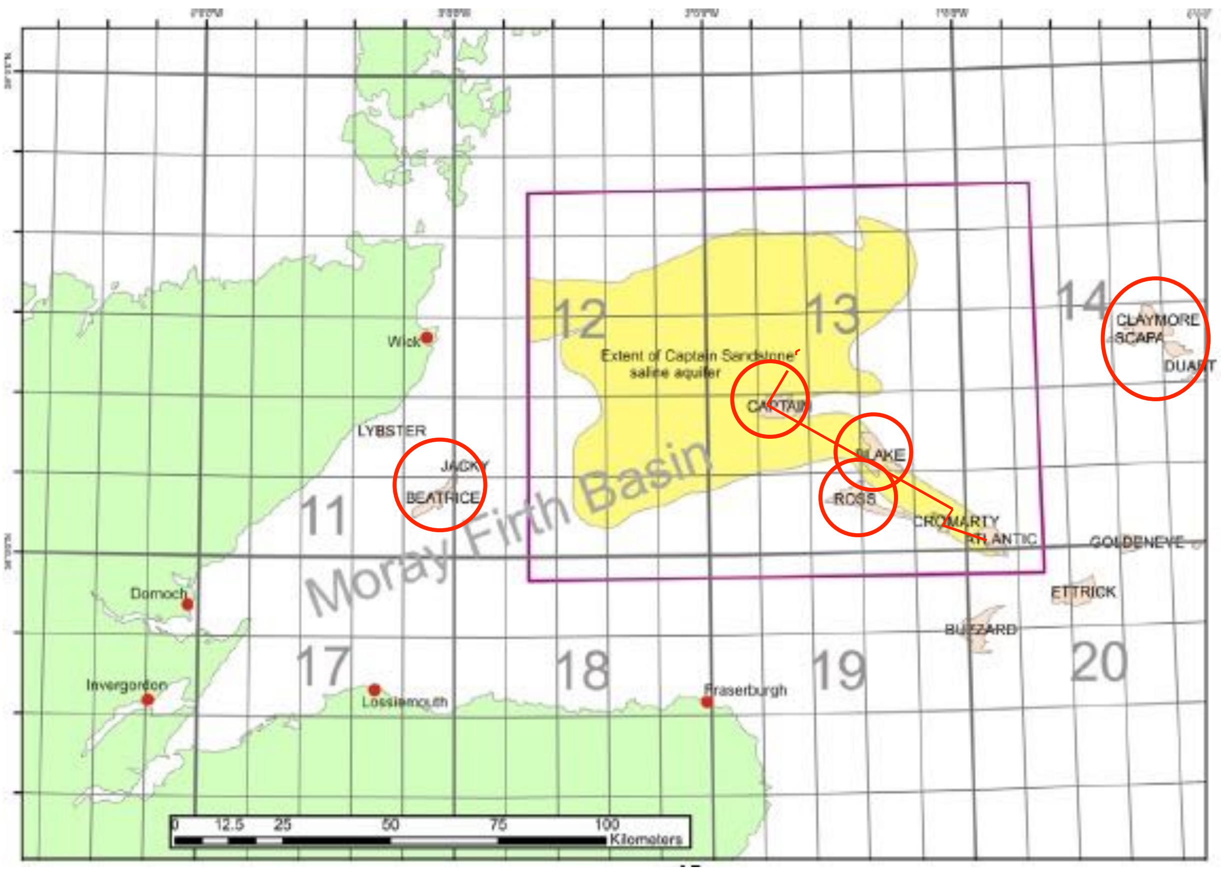
Discussion on Channel Models

- Impact of heterogeneity is significant
- If fine-scale detail is omitted near a well
  - build-up in pressure may be underestimated
  - injectivity may be overestimated
- In models with low sand permeability, injectivity depends on sand:shale ratio
- In models with higher sand permeability, injectivity also depends on facies type (fluvial/turbidite)

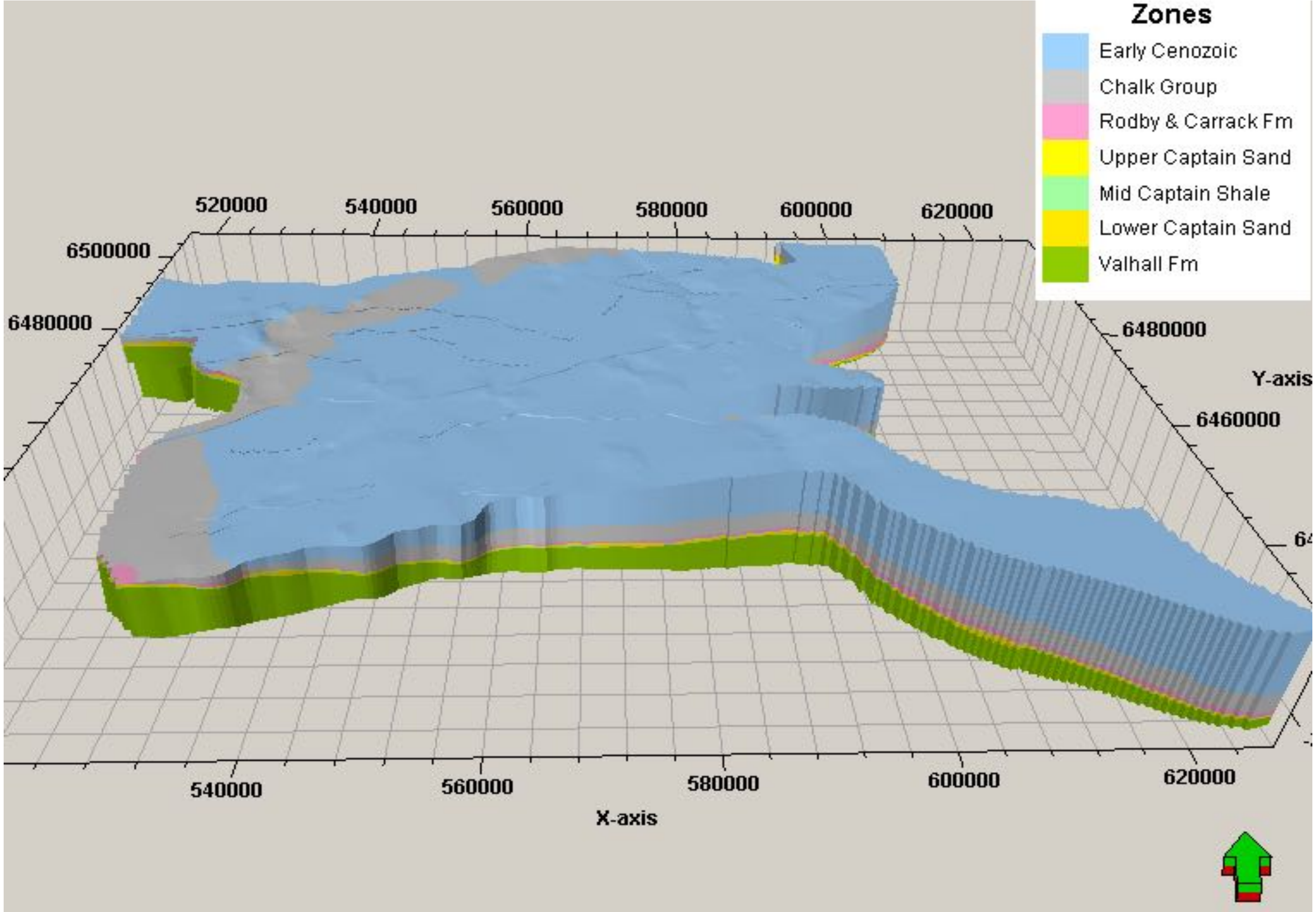
Captain Aquifer

"Progressing Scotland's CO_2 Storage Opportunities"
Government and Joint Industry Project
In collaboration with BGS, Edinburgh

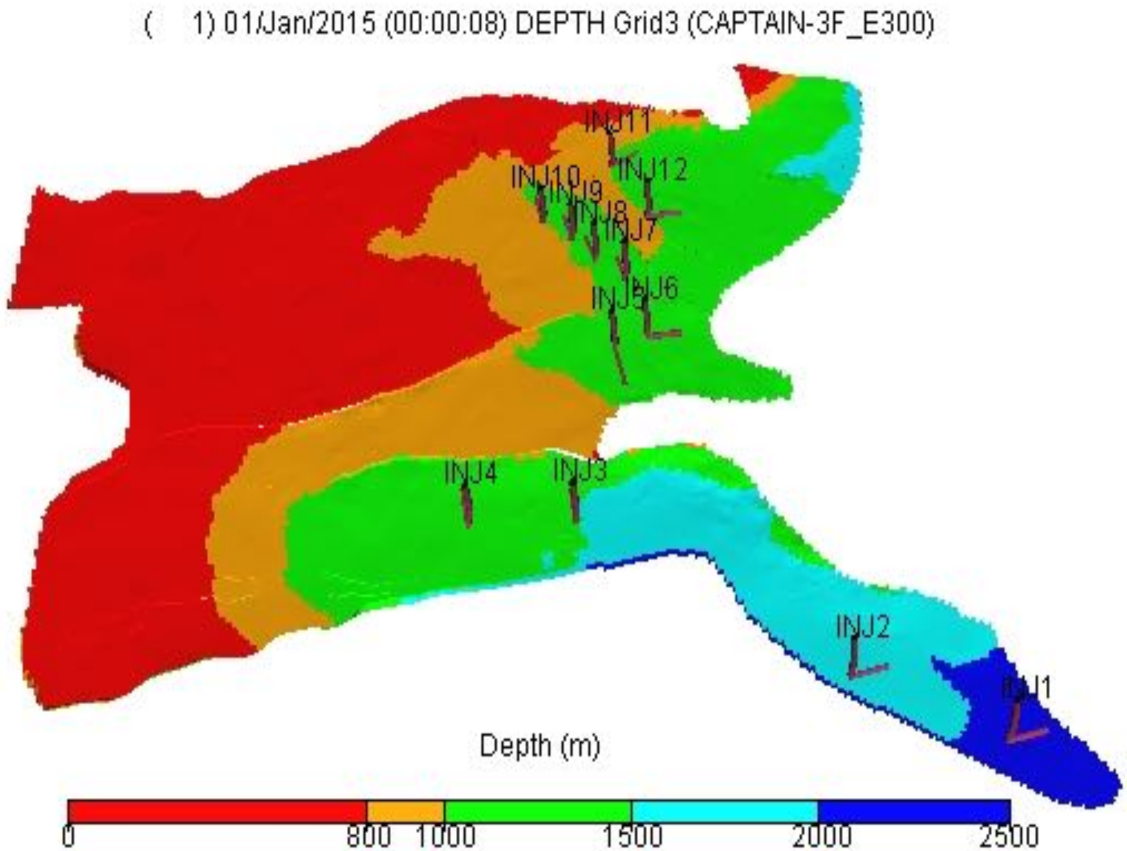
Captain Sandstone Aquifer



Geological Model



Injection Well Locations



Factors Affecting CO_2 Storage

a) If aquifer is "closed"
- pressure build-up
- CO_2 capacity limited by maximum pressure

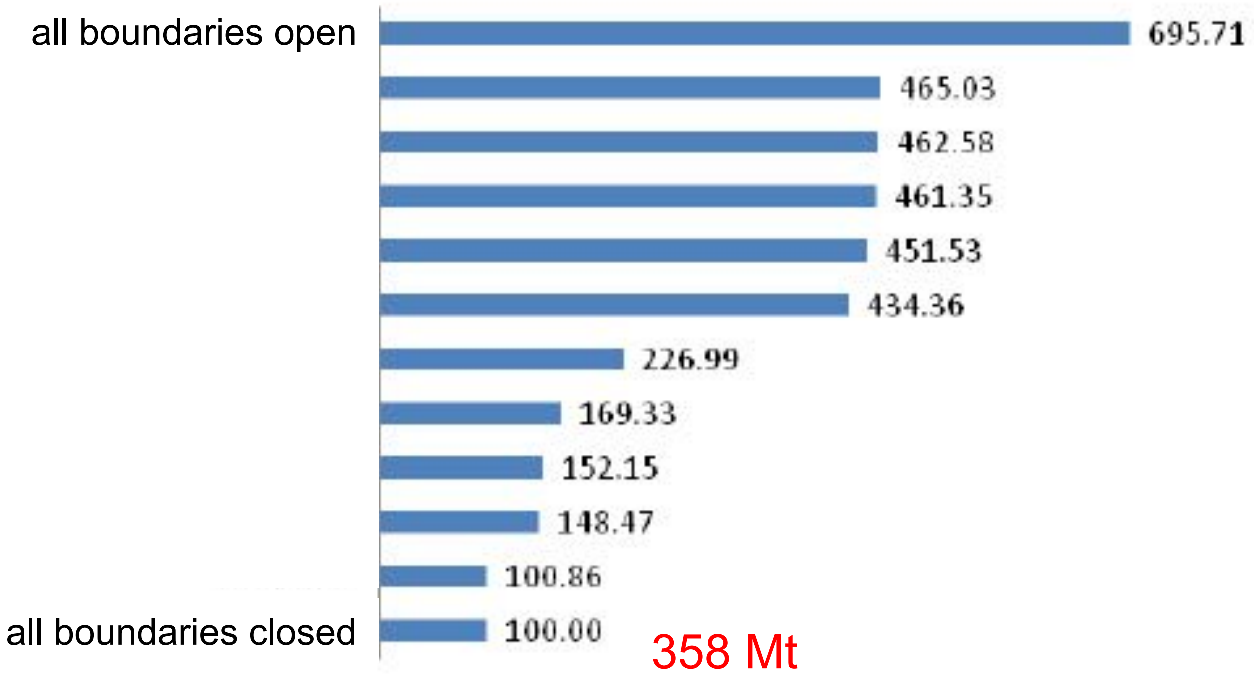
b) If aquifer "open"
- CO_2 may migrate out of storage formation
- Could migrate towards oil reservoirs

c) Transmissibility of faults
- impermeable faults limit migration of CO_2
- but increase local pressure build-up

Jin et al, 2012, SPE 154539

Results

- Large range of storage capacity
- However, some cases are extreme



Other Factors

- There are several hydrocarbon reservoirs in the Captain Formation
  - must not inject within ~ 10 km of these

- Pressure build-up may be mitigated by producing formation water

Conclusions

Conclusions

- Although there are different structures in these models, there are similar problems
- Extent of aquifer
  - the pressure rise depends on the total size of the aquifer, often uncertain
- Size of connected pore volume
  - impermeable barriers will increase pressure build-up
    - impermeable layers or faults
    - inter-channel shales

Conclusions

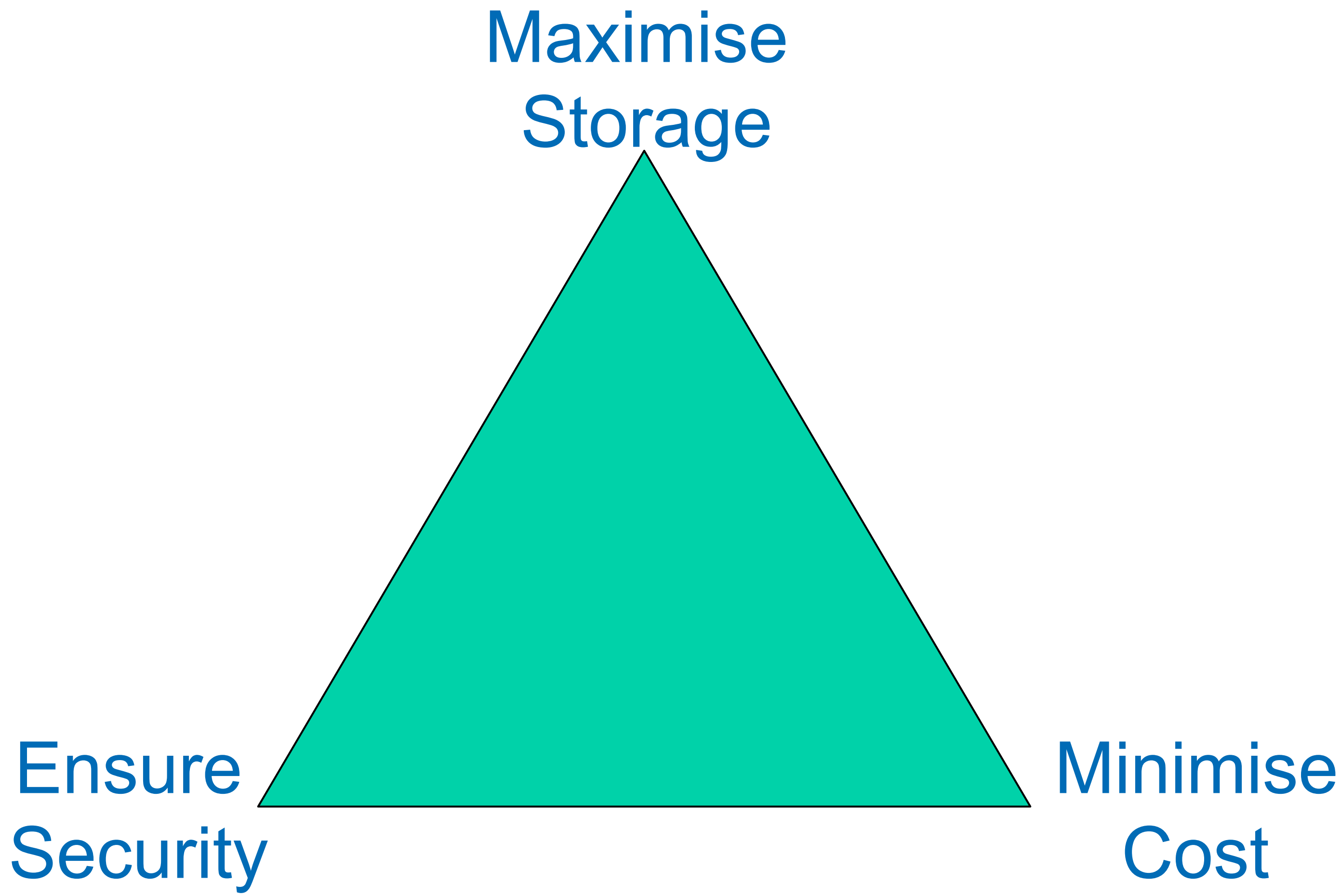
- Possible migration out of storage complex
  - due to heterogeneity, migration pattern is irregular
  - may get migration under horizontal barriers
  - or migration into shallow part of aquifer where CO_2 is sub-critical
  - or migration towards a hydrocarbon reservoir

- However, CO_2 migration is limited by
  - dissolution
  - residual trapping

Additional Factors

- Near-well issues
  - salt deposition
    - could block pores and reduce permeability
  - thermal cooling due to Joule-Thompson effect
    - could adversely affect well equipment

Trilemma



Acknowledgements

- We thank Schlumberger for providing software (Petrel and Eclipse)
- We acknowledge co-workers from BGS and University of Durham
- This work was funded by several companies, including
  - ETI, TCE
- Eric Mackay is funded by Foundation CMG