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CO_2 Storage in a Depleted Gas Reservoir

London SPE Net Zero Programme

June 2022

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Oilfield Production Consultants (OPC)

- Established in 1987
- Global Upstream Technical Services Consultancy
- Experts in Subsurface, Production Engineering and Geosciences
- Clients are NOCs, IOCs and Independents
- Technical Staff, Consultants and Software Technology Resources
- Expert, Independent, and Efficient

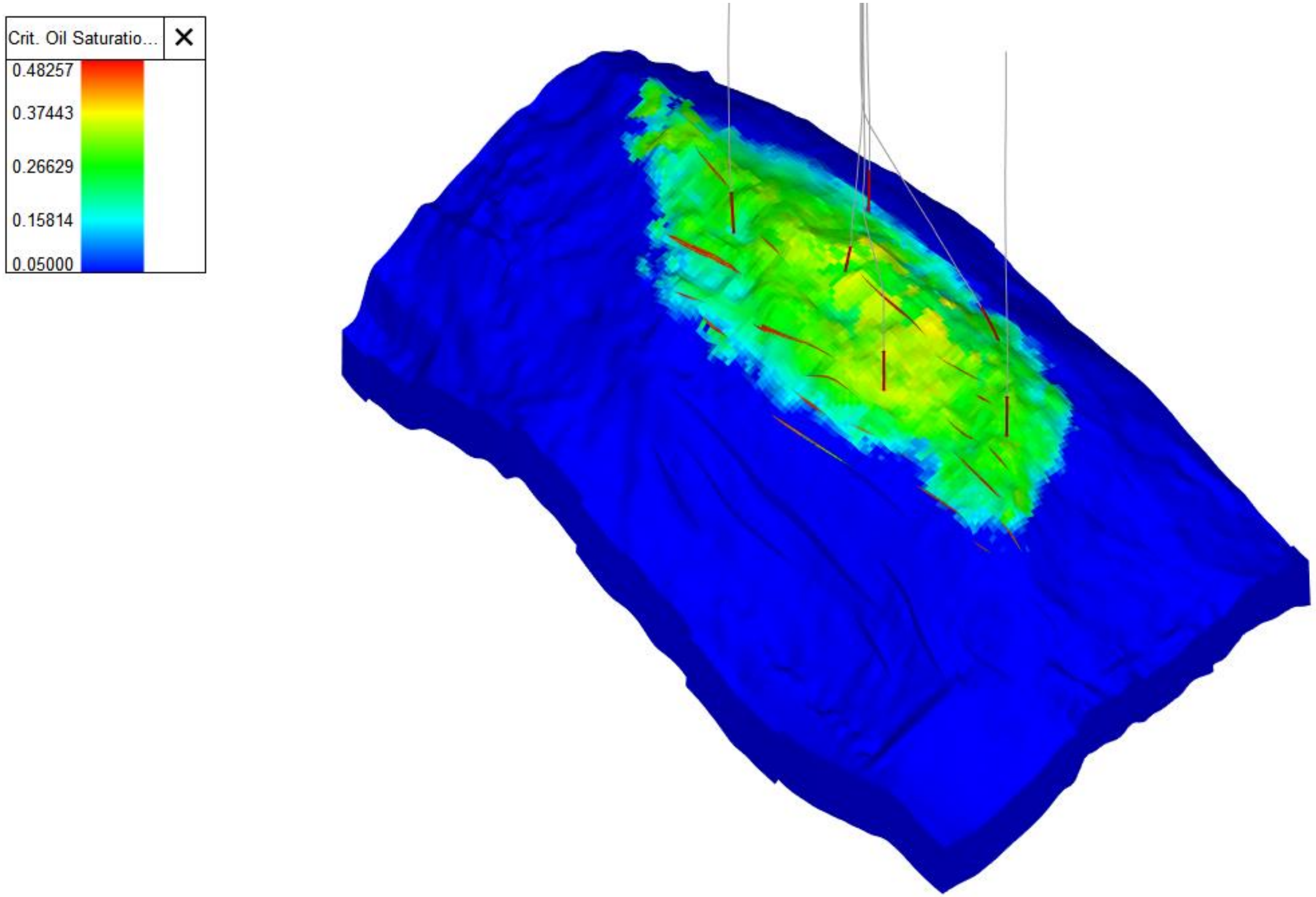
35 Years	47 Countries
761 Clients	6,289 Projects

Offices

8 offices

Background Information

- Offshore dry gas field, sandstone
- Average net thickness 260 – 780 ft
- Permeability 0.4 – 20 mD
- Average porosity 0.08
- Six gas producers
- Seven years of production history
- 2.5 million active cells



CCS Screening Process

Key questions during screening process

Practical capacity evaluated using the simulation model, using rock mechanics consideration

Is the subsurface environment suitable?
- Capacity?
- Injectivity?
- Containment?

Can the storage site be developed cost effectively?
- Suitability of the existing wells
- Suitability of the existing facilities
- Suitability of the pipelines
- High level cost estimate

What is the maturation potential?
- Data availability?
- Uncertainty reduction potential?
- Support to progress the project?

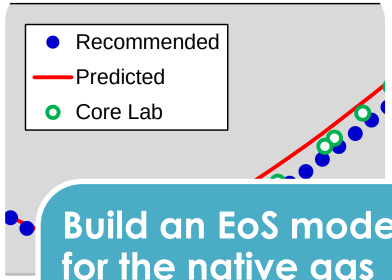
Commerciality
- What price is required to achieve reasonable return on investment
- Contextualisation / Benchmarking

Very briefly assessed during this study

Reasonable assessment

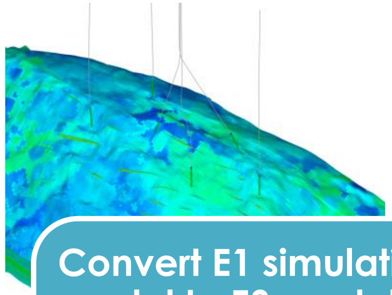
Not looked at

Reservoir Simulation Study Workflow



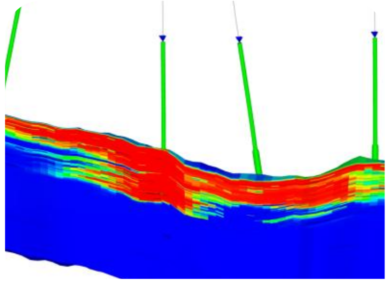
Build an EoS model for the native gas and injected CO_2

- Check consistency with black oil model
- Sensitivities to number of components for run time



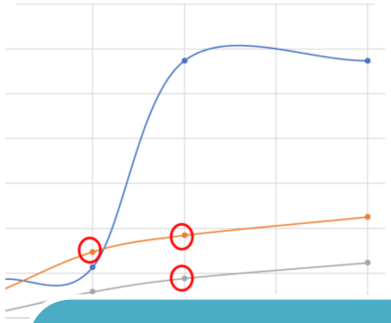
Convert E1 simulation model to E3 model

- Build new saturation model
- Implement E3 PVT model
- Check initial GIIP and HM



Build prediction cases

- Convert producers to injectors
- Build injection scenarios
- Run sensitivities to injection rate, number of wells and timing.



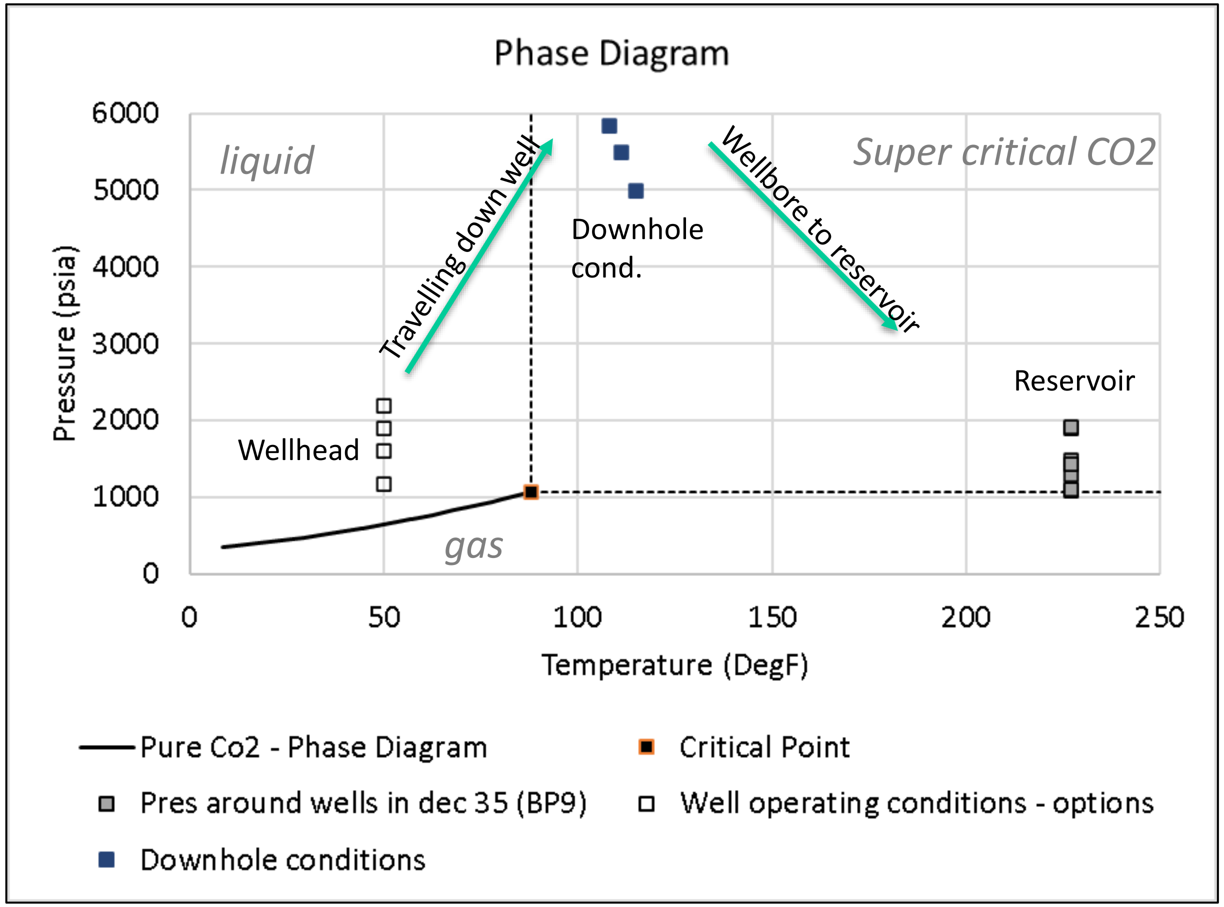
Implement geomechanical constraints

- Maximum injection dP
- Maximum pressure

- Assessment of the practical storage capacity requires use of a compositional simulation model which can model CO_2 properties.
- OPC have converted existing tNav black oil simulation model (E1) to a compositional model (E3) and re-history matched the model.
- The compositional model was used to examine multiple injection scenarios. Prediction runs were typically 4 – 8hrs duration.
- Geomechanical constraints defined by geomechanical study were included.

Introduction

- CCS is considered as one component of a strategy to reduce CO_2 emissions into the atmosphere
- CO_2 injected as a liquid and stored as **supercritical fluid**



Transport:
CO_2 compressed and transported in liquid (dense) phase.
CO_2 gas quality would have to be maintained dry with no free water present at nearly all times.

Storage

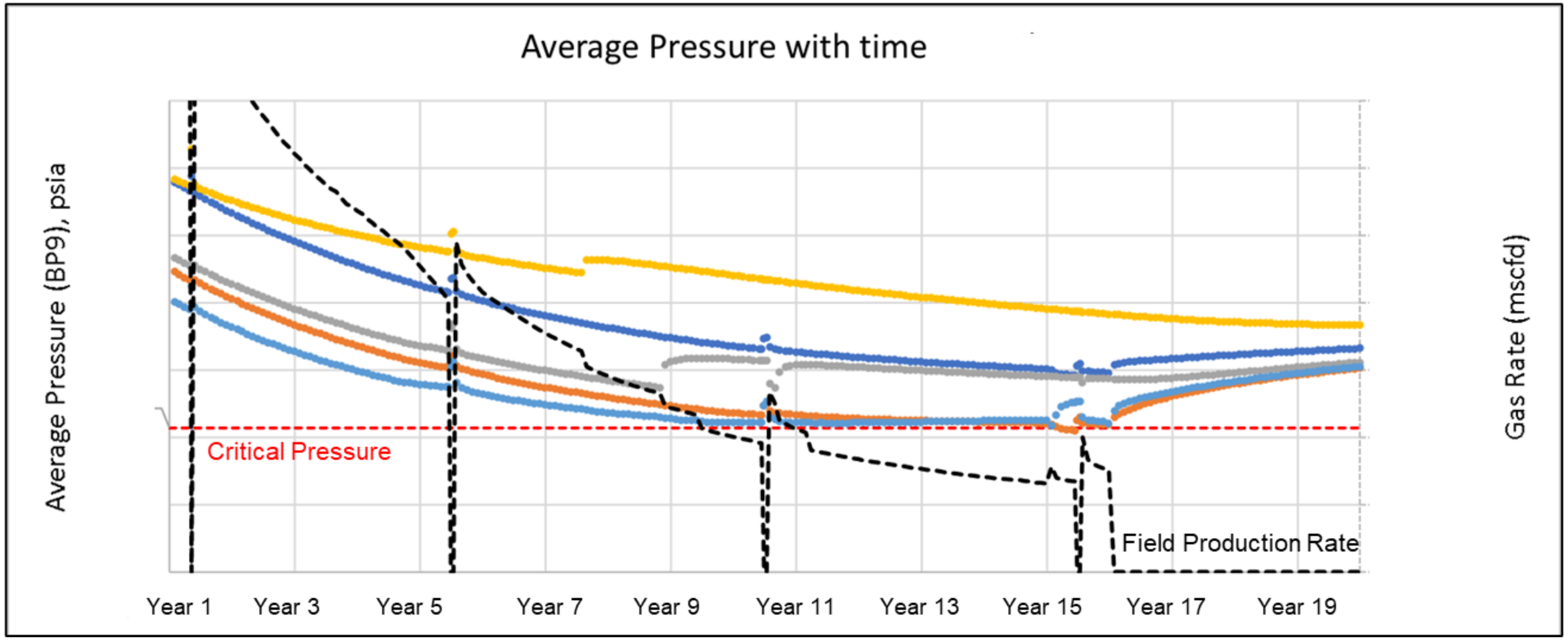
Super-critical CO_2: weighs like a liquid and flows like a gas.

The CO_2 density will still be less than water. The injected CO_2 will migrate to the top of the rock layer because of buoyancy forces.

As we are interested in the long term trapping of the CO_2 for hundreds to thousands of years, it is imperative that the CO_2 cannot escape.

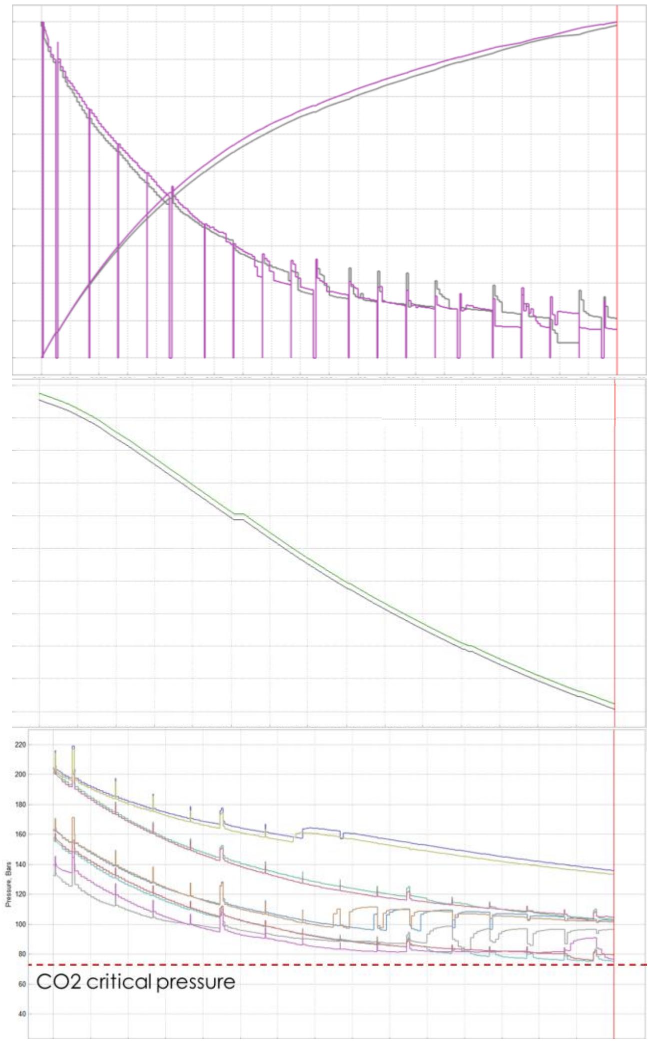
Reservoir Pressure & Temperature

- Initial reservoir pressure 401bar.
- Depleted reservoir pressure expected 75 – 132 bar.
- Ambient reservoir temperature 227˚F.
- BHT during CO_2 injection 108˚F.



Well	Avg. Pressure (BP9) - psia
1	1480
2	1290
3	1090
4	1440
5	1920
6	1100
Field Avg.	1900

Conversion of E1 Model to E3 Model



Key assumptions and modifications:

- Reference black oil history matched base case model.
- The following modifications were made to the model:
  - Implementation of the E3 PVT file. A 9- components model was initially used; subsequently reduced to 6, for run time (similar results).
  - The field is initialised using the initial water saturation grid of the E1 model, for GIIP consistency.
  - The saturation tables were re-built for compatibility with E3.
- Assumptions:
  - It is assumed that the injected fluid contains 100% CO_2.

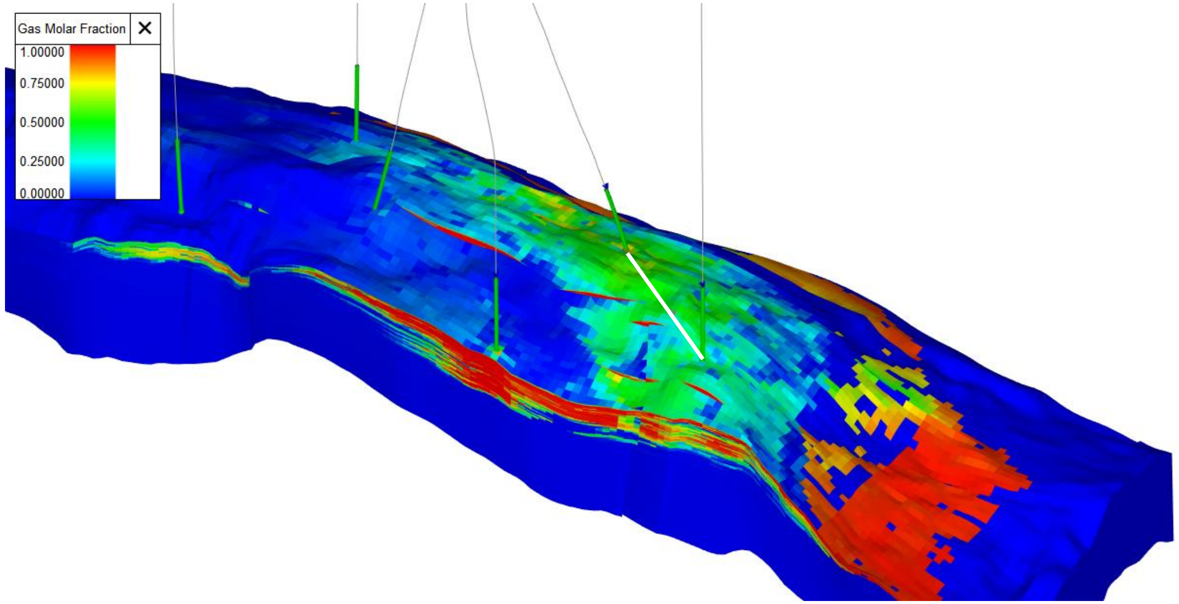
CO_2 Injection Assumptions

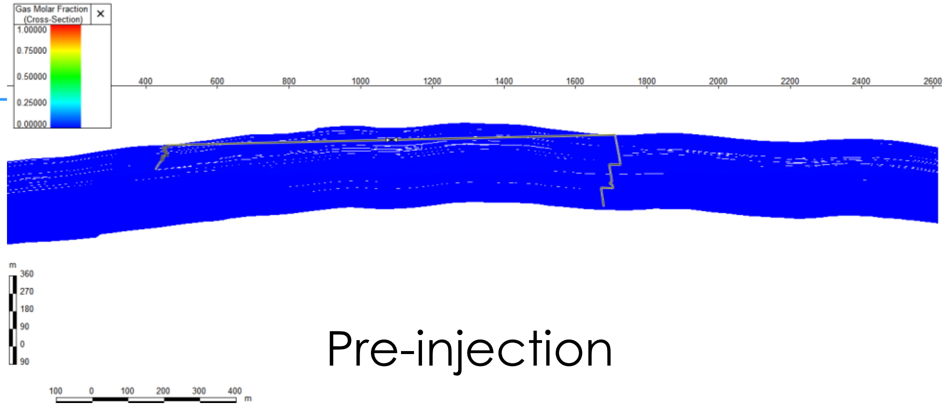
- CO_2 injection start date consistent across all scenarios.
- Injection is controlled by CO_2 injection rate to maintain the constant rate plateau.
- Maximum THP is set by the facilities (limit as reservoir pressure increases).
- Maximum BHP is set by geomechanics (limit as reservoir pressure increases).
- In order to investigate individual well's injectivity and field's suitability to store CO_2 / plume development and optimum practical storage capacity black oil simulation model was converted to compositional model and all producing wells were converted into CO_2 injectors and the following development concepts were tested:
  - Individual well injectivity at 1Mt/y.
  - Higher injectivity wells tested individually for 2 – 3 Mt/y.
  - Combined injection from a number of wells to meet CO_2 injection rate of 1 – 5 Mt/y and to maintain the stable injection rate.

# Wells	Injection Rate, Mt/y
1	1
1	1
1	0.944
1	1
1	1
1	1
2	1
3	1
5	1
1	2
2	2
3	2
5	2
1	3
2	3
3	3
5	3
3	5
5	5

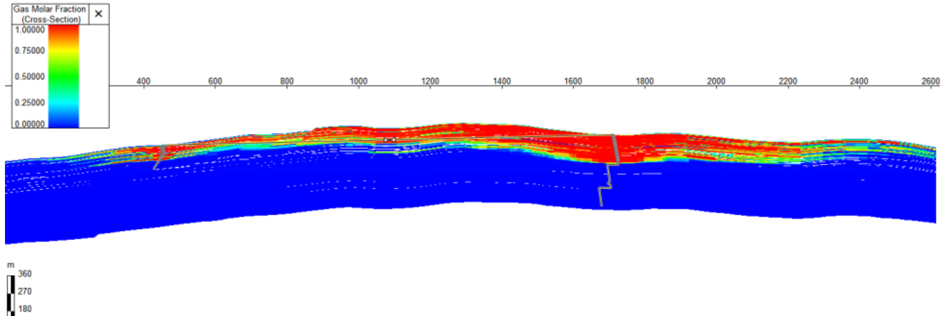
CO_2 Plume Development

- **There are no significant restrictions observed in plume development**
  - Cross-Section through two wells showing the mole fraction of CO_2 pre and post CO_2 injection.
  - Well schedule and sequence as well as combination of different injection strategies would require optimisation at a later stage.

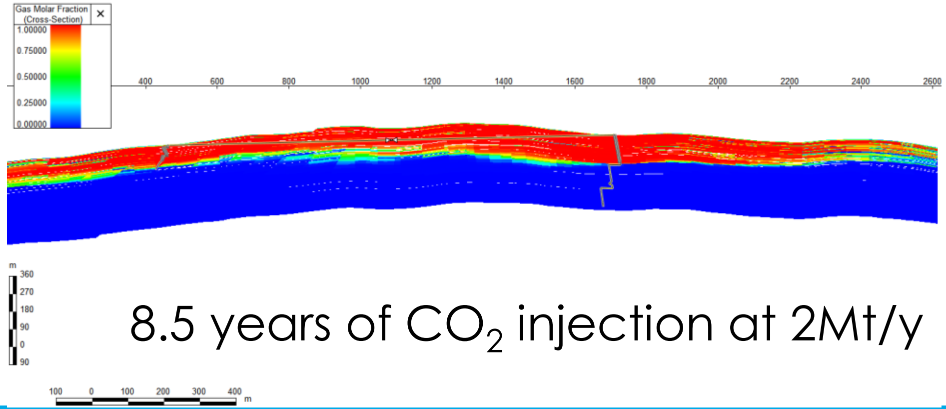




Pre-injection



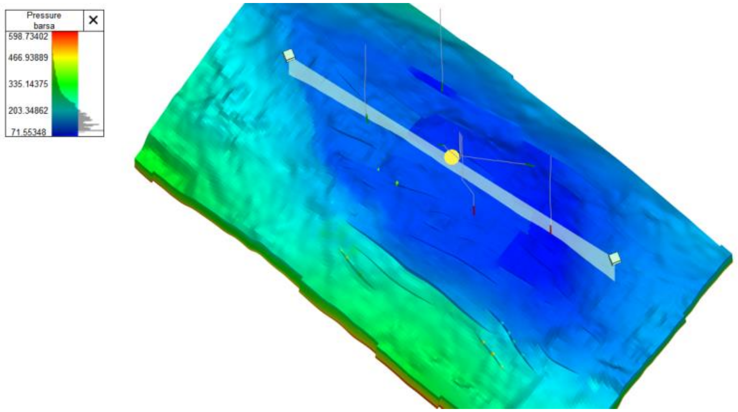
2.5 years of CO_2 injection at 2Mt/y

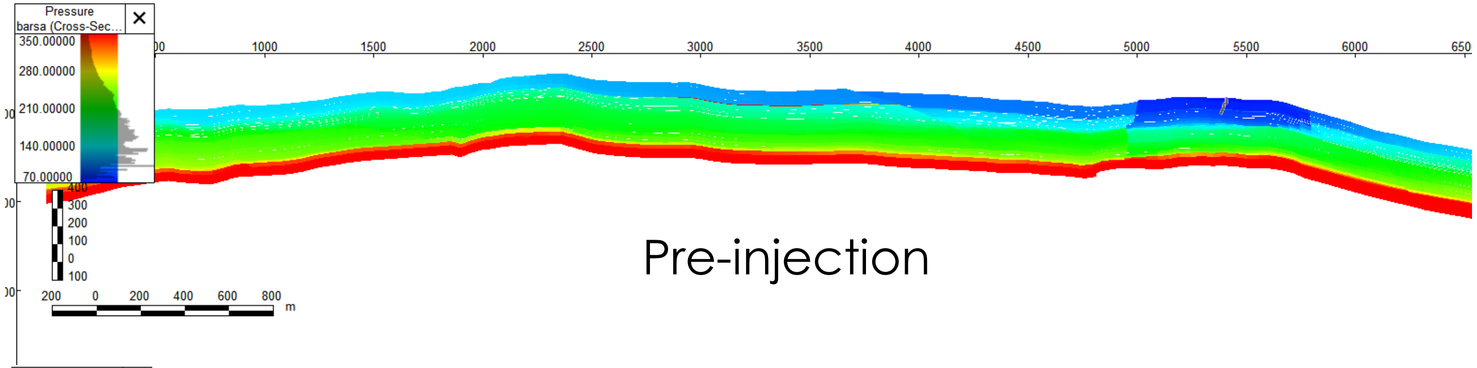


8.5 years of CO_2 injection at 2Mt/y

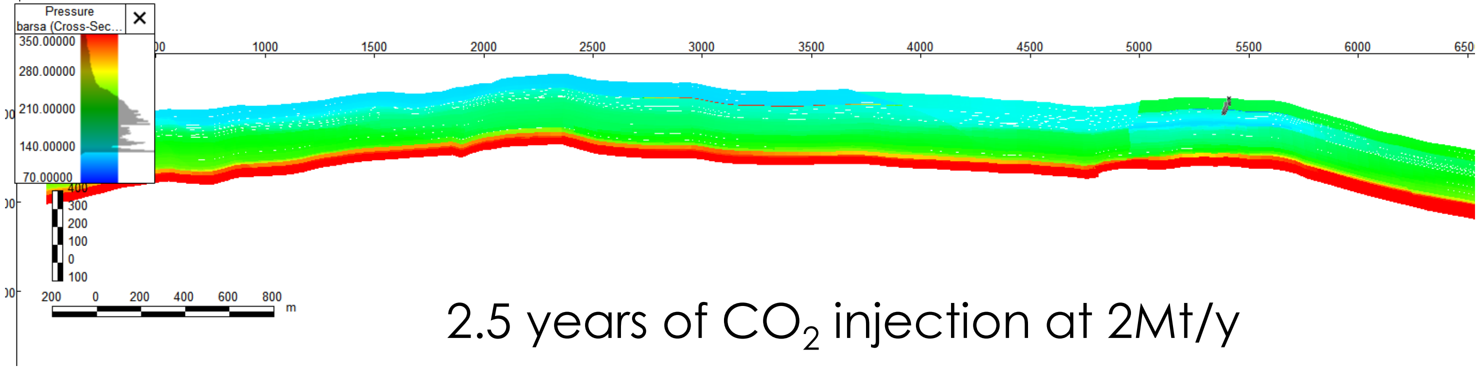
Reservoir Pressure

- Cross-Section through two wells showing reservoir pressure.
- Reservoir pressure increasing around shut-in wells.

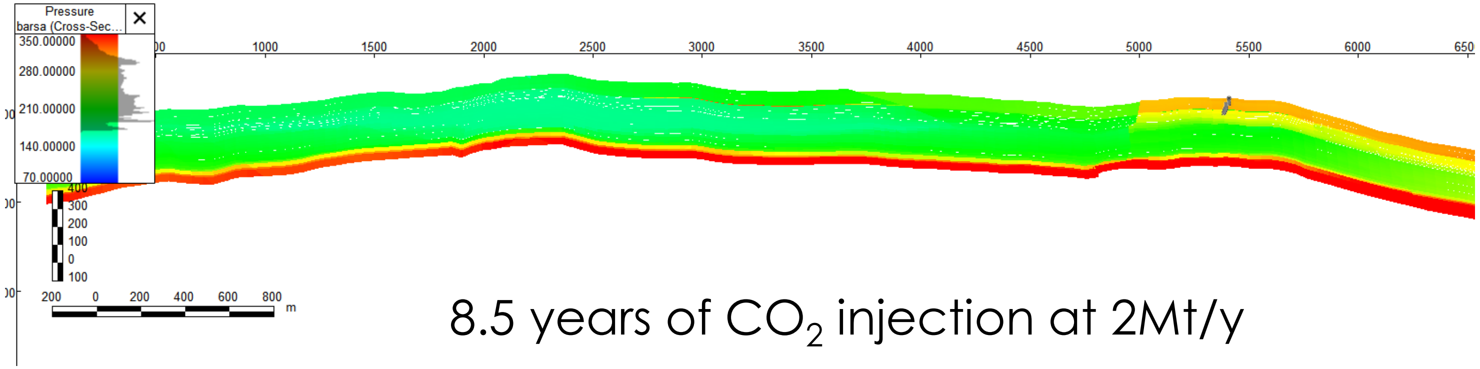




Pre-injection



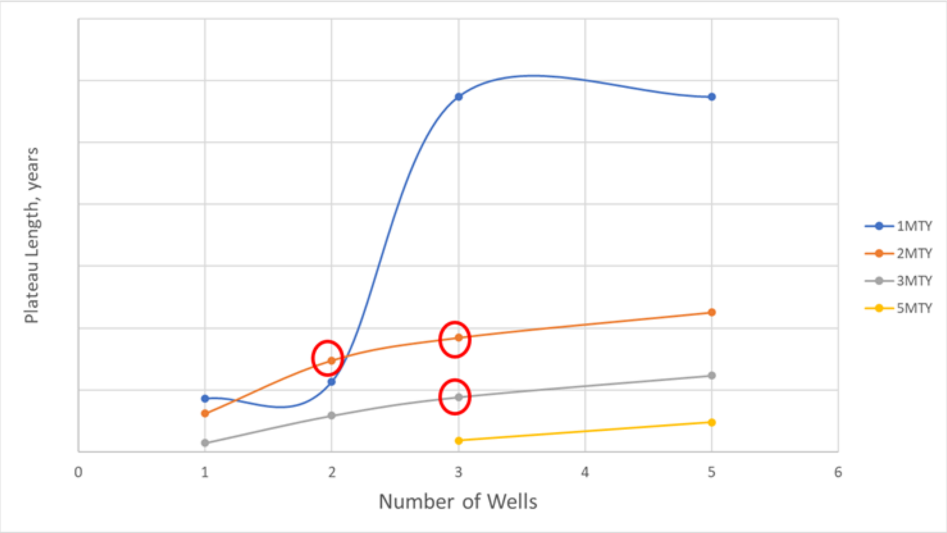
2.5 years of CO_2 injection at 2Mt/y

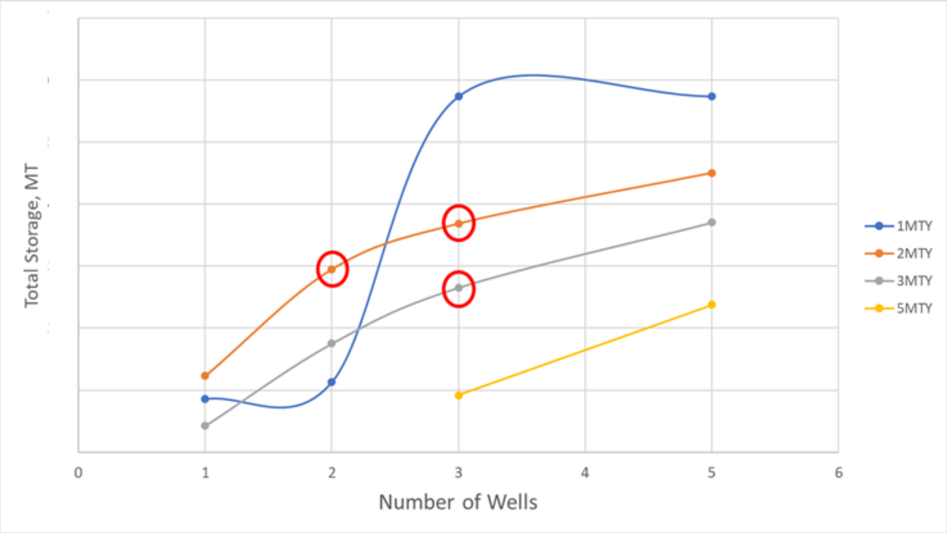


8.5 years of CO_2 injection at 2Mt/y

Reservoir Modelling Conclusions

- The field is capable of storing CO_2, practical storage capacity identified along with the optimum injection concept.
- Geomechanical studies carried out by a recognised industry expert and using measurements from the existing wells confirms that the cap rock strength is sufficient for the reservoir containment of CO_2 at pressure ranges observed in this study.
- Our reservoir modelling work indicates there are no restrictions to plume development and because of this, the reservoir is well suited for the CO_2 storage.
- Reservoir pressure at abandonment is predicted to be close to but higher than the critical pressure for CO_2 which is beneficial as at normal operating conditions it avoids any phase changes/extreme cooling caused by Joule – Thomson effect.





THANK YOU