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Confidentiality
This work should be considered commercial in confidence.
Outline

• Workflow
• Static Model
• Dynamic Models – Radial and Sectoral
• Analytical Probabilistic Computations
• Comparison with previous models
• Appraisal program
Scope of Current Work

- High level objectives:
  - Update existing models from Stage 1b by integrating newly acquired data
  - Assess how the newly acquired data changes the understanding of the area
  - Identify remaining uncertainties
  - Provide input for the development of a new appraisal program
Static Model
Core data has been used to calibrate interpretation.

Pinjarra-1 and Lake Preston 1 reinterpreted as well.
GSWA Harvey 1 Petrophysical Results

- Avg. porosity 23%
- Avg. perm. ~2300 mD
- NtG 37%

- Avg. porosity 13%
- Avg. perm. ~250 mD
- NtG 91%
## Salinity

<table>
<thead>
<tr>
<th></th>
<th>Leederville Formation</th>
<th>Cattamarra Coal Measures</th>
<th>Eneabba Formation</th>
<th>Yalgorup Member</th>
<th>Wonnerup Member</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Pinjarra 1</strong></td>
<td>~1800 ppm</td>
<td>&lt; 400 m, ~1800 ppm</td>
<td>Absent</td>
<td>&lt; 2500 m, ~10000 ppm</td>
<td>~3000-5000 ppm</td>
</tr>
<tr>
<td></td>
<td></td>
<td>&gt; 1050 m, ~3000-42000 ppm</td>
<td></td>
<td>&gt; 2500 m, ~1800 ppm</td>
<td></td>
</tr>
<tr>
<td><strong>Lake Preston 1</strong></td>
<td>No data</td>
<td>Absent</td>
<td>&lt; 500 m, ~3000 ppm</td>
<td>~40000 ppm</td>
<td>&lt; 2140 m, ~20000 ppm</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>&gt; 500 m, ~46000 ppm</td>
<td></td>
<td>&gt; 2140 m, ~2000 ppm</td>
</tr>
<tr>
<td><strong>Harvey 1</strong></td>
<td>No data</td>
<td>No data</td>
<td>No data</td>
<td>~60000 ppm</td>
<td>~50000 ppm</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Fluid sample at 856 m: 52230 ppm</td>
<td></td>
</tr>
</tbody>
</table>

- Different salinity values between each of the three wells
- Possible fluid separation between fault blocks.
  - Each well represents a single data point, and may or may not be representative of the entire block.
  - Whether these faults blocks are hydro-dynamically connected cannot be established from these data alone
Geo-mechanics: 1D-MEM Results

- Mechanical test data were available from a nearby well
  - Good calibration of the 1D-MEM
  - Predicted breakouts correspond to observed breakouts in borehole images and caliper data
- Maximum bottom hole pressure is found, corresponding to 41.2 MPa, at 2200 mMD.
  - Good design practice might assume injection pressure should not exceed 90% of the maximum calculated value.
- Major uncertainties
  - Validate fracture pressure with LOT
  - Use XLOT or mini-frac to calibrate frac pressure and minimum horizontal stress
Static Model: Structure is more compartmentalised

- New seismic changed the understanding of the area around Harvey 1
- New interpretation reconciles the new seismic data with publications on fault orientations in the Perth Basin
- Area is now more faulted
Fault truncated according to the chronological sequence of the tectonic events: *younger faults cut older faults*

- Late Jurassic - Early Cretaceous (NE-SW)
- Late Triassic - Early Jurassic (NW-SE)
- Permo-Triassic (NS)

Each family divided into 3 different classes based on uncertainty:

- Class 1: clearly visible on multiple seismic lines
- Class 2: less defined, lateral extent has some uncertainty
- Class 3: poorly defined, lateral extent highly uncertain

Comprised of 50 fault parts (cf 21 faults in Stage 1b model)

Four horizons modelled:
- Unconformity (Early Cretaceous)
- top Yalgorup Member
- top Wonnerup Member
- base Sabina Sandstone

The three different fault generations are shown: green indicates Late Jurassic - Early Cretaceous (NE-SW), blue indicates Late Triassic - Early Jurassic (NW-SE), and pink/purple indicates Permo-Triassic (NS).
Structural Model – Horizons

- Four horizons modelled explicitly:
  - Unconformity (Early Cretaceous)
  - top Yalgorup Member
  - top Wonnerup Member
  - base Sabina Sandstone
Facies Modelling

- Approach replicated from Stage 1b – *object modelling*
- Uses analog for channel dimensions
- Orientation from outcrop studies to the north
- Sand, silt and shale
- Three facies models created
  - Base Case (same cut-offs as Stage 1b)
  - High Silt Case
  - High Shale Case
Porosity Field

- **Spatially distribute effective porosity, permeability and net-to-gross**

- Porosity field distributed by Sequential Gaussian Simulation
  - Constrained by same variogram as Stage 1b (from analogue)
Permeability

- Permeability fields were generated using logs from the petrophysical interpretation
- Permeability was distributed using Gaussian random function simulation
- Distribution is trended to porosity and guided by variogram
- Borehole quality affects permeability, and will therefore affect the property field
- Core data is used where sections of log are washed out
Confidence in Net-to-Gross

Well data matches field data, giving us confidence that we are replicating observed data.
Simulation Grid

- Grid size of the entire model is ~18 million cells
  - Too large for simulation
- How do we reduce the number of cells?
  - Common practice in O&G to **upscale the geological model**
  - Change the size of the grid cells or the number of layers
    - For this work, we want to keep the fine layer detail, **so we change the grid size**
- Focus the simulation grid **around the planned 3D seismic area** and takes into consideration faults
Full Area
150x150 m grid cell size
18 million cells

Cropped & Upscaled Area
300x300 m grid cell size
~0.60 million cells
Dynamic Models
• Three types of modelling are used to assess the CO₂ storage potential.
• Each of these types of models is used to assess certain questions or aspects.
• The types of modelling are:

  Dynamic Radial Simulations
  What is the effect of certain assumptions on overall injectivity?
  What is the pressure evolution given different boundary conditions?

  Dynamic Sector Models
  What levels of sustained injectivity can be attained in the model?
  What level of capacity can be achieved within the project lifetime?

  Probabilistic Models
  What is the uncertainty on parameters affecting injectivity?
  How likely is achieving the targeted injection rates given the current uncertainty level?
• *Dynamic radial models* are used to qualitatively explore the impact of certain assumptions on injectivity.

• Radial model is built from the Wonnerup Member portion of the Harvey 1 well.

• The assumptions and assessment parameters chosen for particular reasons are:
  1. Compartment size, i.e. distance to no-flow boundary
  2. Permeability upscaling approach
  3. Grid layer thickness
  4. Relative permeability end-point.
Input Data and Constraints

- Reservoir Properties (Permeability, NTG, porosity) from ELAN, kv-kh ratio of 0.1
- Simulation restricted to Wonnerup Member
- E300 CO2Store (compositional)
- Boundary conditions
  - Injection rate is limited by an imposed fracture gradient (0.149 bar/m), otherwise freely
  - Injection interval: 2283 – 2410 MD – criterion: relatively deep and thick sand package
    - Fine grid: 135 m (27 cells @ 5m)
    - Coarse grid: 100 m (2 cells @ 50m)
  - 30 years of injection
  - Injection into a saline aquifer (60000 ppm) – mean out of ELAN analysis
  - Initially in hydrostatic equilibrium (190 bar @ 1913 m) – RCI tool
  - Temperature vs. Depth as measured – RCI tool
  - Relative Permeability: Viking (Bachu)
Upscaling Results - Permeability

Geometric Upscaling

Harmonic Upscaling

Fine Layering

Coarse Layering
Injection Profiles – Tank Size

Radial Model - Boundary Conditions

- 5km Harmonic
- 10km Harmonic
- 5km Geometric
- 10km Geometric

Mass Rate [Mt/y] vs. Time [yrs]
Injection Profiles – Layer Thickness

Radial Model - Fine vs. Coarse

- 5km Harmonic
- 5km Geometric
- 5km Harmonic Coarse
- 5km Geometric Coarse

Mass Rate [Mt/y] vs. Time [yrs]
Injection Profile – Relative Permeability

Radial Model - Relative Permeability

- Mass Rate [Mt/y]
- Time [yrs]
- 5km Geometric
- 10km Geometric
- 5km Geometric No Dryout
- 10km Geometric No Dryout
Discussion

• Boundary conditions
  – *Compartmentalisation expected to be a major factor on injectivity.*

• Upscaling approach
  • *Geometric better represents the data in this area*

• Grid cell layer thickness 5 m and 50 m
  • *Use finer grid sizes in areas of interest*

• Relative permeability end-point
  • *For the dynamic sector model, the dry-out addition should be allowed, as it expected to happen in the near well-bore.*

• Using Harvey 1 data as representative single well data, given the different boundary conditions, the results indicate that ~1-3 Mt/a of CO2 could be injected.
Dynamic Sector Models

- **Modeling Area**
  - East Boundary: Darling fault
  - Minimum Size: Seismic Survey Area
  - 2000 m Isochore of Top Wonnerup

- **Numerical Model**
  - Cell size: 300x300 meter
  - 591776 active cells
**Injection Well Location and Perforation**

- **Placement Criteria**
  - At least 9 wells
  - Quite down-dip
  - Distant from Faults
  - Placed in main fault compartments

- **Perforations**
  - Maximize KH
  - Lower Wonnerup Member
  - Roughly 700 m per well
Boundary and Initial Conditions

- Rel.Permt curves after Ali Saeedi
  - Imbibition curve created by normalization of drainage curve
- Salinity: 60,000 ppm
- Carter Tracy aquifer on 3 edges
- Constant pressure aquifer on top
- Hydrostatic equilibrium
- Injection
  - Target Field rate of SWPH imposed
  - BHP constraint (90 of frac-pressure)
<table>
<thead>
<tr>
<th>Scenario No.</th>
<th>Property Field</th>
<th>Wells</th>
<th>Faults</th>
<th>Boundary</th>
<th>Top Aquifer</th>
<th>Transmissibility Multiplier</th>
</tr>
</thead>
<tbody>
<tr>
<td>S1</td>
<td>Base Case</td>
<td>9</td>
<td>Open</td>
<td>Open</td>
<td>Open</td>
<td>NTG^2</td>
</tr>
<tr>
<td>S2</td>
<td></td>
<td>8</td>
<td></td>
<td>Closed</td>
<td></td>
<td></td>
</tr>
<tr>
<td>S3</td>
<td></td>
<td>9</td>
<td>Closed</td>
<td>Open</td>
<td>Closed</td>
<td></td>
</tr>
<tr>
<td>S4</td>
<td></td>
<td>9</td>
<td></td>
<td>Open</td>
<td>Closed</td>
<td></td>
</tr>
<tr>
<td>S5</td>
<td>Shale Case</td>
<td>9</td>
<td></td>
<td>Open</td>
<td></td>
<td>NTG^2</td>
</tr>
<tr>
<td>S6</td>
<td>Silt Case</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>S7</td>
<td></td>
<td>9</td>
<td>Open</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>S8</td>
<td>Base Case</td>
<td>9</td>
<td></td>
<td>Open</td>
<td></td>
<td>NTG^2</td>
</tr>
<tr>
<td>S9</td>
<td></td>
<td>9 with Drilling Priority</td>
<td>Open</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Results: Injectivity

- All scenarios apart from S2 and S4 can achieve the target rate
- Effect of closed boundaries apparent

<table>
<thead>
<tr>
<th>Scenario No.</th>
<th>Total injected mass [Mt]</th>
</tr>
</thead>
<tbody>
<tr>
<td>S1</td>
<td>236.4</td>
</tr>
<tr>
<td>S2</td>
<td>236.0</td>
</tr>
<tr>
<td>S3</td>
<td>236.4</td>
</tr>
<tr>
<td>S4</td>
<td>188.1</td>
</tr>
<tr>
<td>S5</td>
<td>236.4</td>
</tr>
<tr>
<td>S6</td>
<td>236.4</td>
</tr>
<tr>
<td>S7</td>
<td>236.4</td>
</tr>
<tr>
<td>S8</td>
<td>236.4</td>
</tr>
<tr>
<td>S9</td>
<td>236.4</td>
</tr>
</tbody>
</table>
Plume migration and Distribution of CO$_2$

- Observations 250 years after injection stop
- Extent is strongly dependent on the property field
- The plume enters the Yalgorup Member

<table>
<thead>
<tr>
<th>Scenario No.</th>
<th>Formation</th>
<th>Total injected mass [Mt]</th>
<th>Dissolved</th>
<th>Immobile</th>
<th>Mobile</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>[mass % of total CO$_2$]</td>
<td></td>
<td></td>
</tr>
<tr>
<td>S1</td>
<td>Yalgorup</td>
<td>236.4</td>
<td>&lt;0.1</td>
<td>&lt;0.1</td>
<td>&lt;0.1</td>
</tr>
<tr>
<td></td>
<td>Wonnerup</td>
<td></td>
<td>39</td>
<td>55</td>
<td>6</td>
</tr>
<tr>
<td>S4</td>
<td>Yalgorup</td>
<td>188.6</td>
<td>&lt;0.01</td>
<td>&lt;0.01</td>
<td>&lt;0.01</td>
</tr>
<tr>
<td></td>
<td>Wonnerup</td>
<td></td>
<td>41</td>
<td>52</td>
<td>6</td>
</tr>
<tr>
<td>S7 (Shale Case)</td>
<td>Yalgorup</td>
<td>236.4</td>
<td>1</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>Wonnerup</td>
<td></td>
<td>43</td>
<td>47</td>
<td>7</td>
</tr>
<tr>
<td>S8 (Silt Case)</td>
<td>Yalgorup</td>
<td>236.4</td>
<td>5</td>
<td>6</td>
<td>3</td>
</tr>
<tr>
<td></td>
<td>Wonnerup</td>
<td></td>
<td>40</td>
<td>43</td>
<td>2</td>
</tr>
</tbody>
</table>
At Shut-In (Base Case S1)
At Shut-In (Silt Case S8)
Plume Migration (Base Case S1) 250 years post Shut-In
Plume Migration (Shale Case S7) 250 years post Shut-In
Plume Migration (Silt Case S8) 250 years post Shut-In
• Only under the consideration of fully sealing faults, the total amount of CO$_2$ injected could not meet the project target.
• At least 8 wells with quite long perforations are necessary.
• Higher effective permeability (relative permeability times absolute permeability) in combination with some pressure relief wells might meet the project requirements even under the consideration of sealing faults.
• CO$_2$ generally stays in the Wonnerup Member, and only a small amount entering the Yalgorup Member.
● Analytical Model
  – Injection rate per individual play
  – Injection rate per well
  – Injection rate per basin development

● Darcy law approximation for high pressure compressible fluid flow: valid if $\mu_B \sim$ constant (pressure > 2000 psi)

● $\text{CO}_2$ viscosity and formation volume factor, $\rho_{\text{CO}_2}$ and $B_{\text{CO}_2}$, evaluated at an average pressure (between $P_{\text{res}}$ and $P_{\text{inj}}$)

$$ q_{\text{CO}_2} = \frac{k_{\text{absolute}} k_{r\text{CO}_2} h_{\text{gross}} NTG(p_{\text{inj}} - p_{\text{res}})}{25.15 \mu_{\text{CO}_2} B_{\text{CO}_2} \left[ \ln \left( \frac{r_e}{r_w} \right) - 0.75 + S \right]} $$
8 Variables for Monte Carlo

1. Gross thickness (based on static model of the Lower Wonnerup)
2. Net-to-gross thickness ratio (based on static model of the Lower Wonnerup)
3. Middle reservoir depth (based on static model of the Lower Wonnerup)
4. Permeability (based on static model of the Lower Wonnerup)
5. Fracture gradient (1D-MEM)
6. Initial pore pressure gradient (based on measurement)
7. CO$_2$ relative permeability (from technical literature)
8. Wellbore skin (oil and gas practices)
PDFs used for probabilistic modelling

<table>
<thead>
<tr>
<th>Number</th>
<th>Property</th>
<th>Unit</th>
<th>Probability Distribution</th>
<th>Mean or Likeliest</th>
<th>Standard Deviation</th>
<th>Truncation Limits</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Gross Thickness</td>
<td>m</td>
<td>Normal</td>
<td>913</td>
<td>147</td>
<td>459 - 1340</td>
</tr>
<tr>
<td>2</td>
<td>Net-to-Gross</td>
<td>adimensional</td>
<td>Custom</td>
<td>0.77</td>
<td></td>
<td>0 - 1</td>
</tr>
<tr>
<td>3</td>
<td>Middle Reservoir Depth</td>
<td>m</td>
<td>Gamma</td>
<td>2349</td>
<td></td>
<td>1794 - 3220</td>
</tr>
<tr>
<td>4</td>
<td>Permeability</td>
<td>mD</td>
<td>Gamma</td>
<td>48.7</td>
<td></td>
<td>0 - 700</td>
</tr>
<tr>
<td>5</td>
<td>Fracture Gradient</td>
<td>psi/ft</td>
<td>Normal</td>
<td>0.826</td>
<td>0.082</td>
<td>0.75 – 0.9</td>
</tr>
<tr>
<td>6</td>
<td>Initial Pore Pressure Gradient</td>
<td>bar/m</td>
<td>Normal</td>
<td>0.1</td>
<td>0.01</td>
<td>0.09 – 0.11</td>
</tr>
<tr>
<td>7</td>
<td>CO₂ Relative Permeability</td>
<td>adimensional</td>
<td>Uniform</td>
<td>0.25</td>
<td></td>
<td>0.1 – 0.4</td>
</tr>
<tr>
<td>8</td>
<td>Skin</td>
<td>adimensional</td>
<td>Normal</td>
<td>4</td>
<td>2</td>
<td>-2 to 10</td>
</tr>
</tbody>
</table>
Examples of PDFs used for probabilistic modelling

- **Gross Thickness**
- **Middle Reservoir Depth**
- **NTG**
Results of Probabilistic Study

### Sensitivity: Injection Rate

- **Absolute Permeability**: 93.8%
- **NTG**: 3.9%
- **CO2 Relative Permeability**: 1.7%
- **Skin**: -0.2%
- **Gross Thickness**: 0.2%
- **Pressure Gradient**: -0.1%
- **Fracture Gradient**: 0.1%
- **Middle Reservoir Depth**: 0.1%

### Injectivity Lower Wonnerup Member

<table>
<thead>
<tr>
<th></th>
<th>Median (P50)</th>
<th>P90</th>
<th>P10</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Injection Rate</strong> [t/d]</td>
<td>3784</td>
<td>0.4</td>
<td>141000</td>
</tr>
<tr>
<td><strong>Injection Rate</strong> [Mt/a]</td>
<td>1.3</td>
<td>0.000146</td>
<td>51.5</td>
</tr>
</tbody>
</table>
Comparison with Numerical Simulation

Injection Rate: Scenario No. 1

![Graph showing injection rate over time for different scenarios. The x-axis represents time in years (0 to 40), and the y-axis represents rate in Mt/a. Each scenario is represented by a different line color. The line styles vary to distinguish between scenarios. The graph includes a legend indicating the scenarios such as II10N3, II11N3, II12N3, II16N3, II17N3, II5N3, II6N3, II7N3, and II8N3.](image)
Comparisons with previous work
In this Section, the present work will be compared and contrasted with the previous Stage 1a/1b work to record progress in understanding of the area of interest and to discuss uncertainty reduction.

- New and old petrophysical interpretation, and how Harvey 1 changes the reservoir properties
- New and old structural models
- New and old dynamic sector and probabilistic models

This work contains several new pieces of work, such as fluid substitution and dynamic radial models, that cannot be compared to previous work.
Petrophysical Interpretation

- Pinjarra 1 and Lake Preston 1 were reinterpreted in addition to Harvey 1.
- There are various methodology differences between to the interpretations.
- Average porosity is higher in the new study by as much as 6 porosity units in Lake Preston 1 Yalgorup Member (Table 10-1).
- In other wells and formations, the difference between the old and new values is not as large.

<table>
<thead>
<tr>
<th>Yalgorup Member</th>
<th>Stage 1a/1b</th>
<th>Subsurface Modelling Update</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Avg. PHIE [%]</td>
<td>NtG</td>
</tr>
<tr>
<td>Well</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Lake Preston 1</td>
<td>13.2</td>
<td>0.68</td>
</tr>
<tr>
<td>Pinjarra 1</td>
<td>8.0</td>
<td>0.335</td>
</tr>
<tr>
<td>Wonnerup Member</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Avg. PHIE [%]</td>
<td>NtG</td>
</tr>
<tr>
<td>Lake Preston 1</td>
<td>8.2</td>
<td>0.441</td>
</tr>
<tr>
<td>Pinjarra 1</td>
<td>5.2</td>
<td>0.056</td>
</tr>
</tbody>
</table>
Static Model

- The differences between the Stage 1a/1b and current models in terms of number of cells, grid size, layers and area do not necessarily imply that one model is more correct than the other.
- Indicate the parameters chosen by the modeller to represent the data.
- Biggest difference – number of faults in the Area of Interest:
  - Structure is considerably more complex than previously thought.
  - Largely attributed to the previous lack of seismic control in the simulation area.
- Model areas are roughly similar and overlap closely.

<table>
<thead>
<tr>
<th></th>
<th>Stage 1a/1b</th>
<th>Subsurface Modelling Update</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Geological Model</td>
<td>Simulation Model</td>
</tr>
<tr>
<td>Area [km²]</td>
<td>1505</td>
<td>357</td>
</tr>
<tr>
<td>Cells</td>
<td>4.5 million</td>
<td>287280</td>
</tr>
<tr>
<td>Grid Size [m]</td>
<td>300x300</td>
<td>400x400</td>
</tr>
<tr>
<td>Layers</td>
<td>3223</td>
<td>135</td>
</tr>
<tr>
<td>Number of Fault Segments</td>
<td>21</td>
<td>6</td>
</tr>
</tbody>
</table>
Static Model

- New seismic data and interpretation changed the understanding of the Area of Interest significantly
- No considerable change in formation thickness
  - 3% difference for the Yalgorup Member
  - 8% difference for the Wonnerup Member
- Depths of each formation are significantly changed
  - Overall, the members are 300-350 m shallower than previously thought
- There are more dip angles >10°, implying steeper horizons

<table>
<thead>
<tr>
<th></th>
<th>Yalgorup Member</th>
<th>Wonnerup Member</th>
<th>Yalgorup Member</th>
<th>Wonnerup Member</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Depth [m]</strong></td>
<td>Min: -670</td>
<td>Max: -2160</td>
<td>Min: -395</td>
<td>Max: -1730</td>
</tr>
<tr>
<td></td>
<td>Mean: -1240</td>
<td></td>
<td>Mean: -1900</td>
<td></td>
</tr>
<tr>
<td><strong>Thickness [m]</strong></td>
<td>20</td>
<td>1020</td>
<td>50</td>
<td>1095</td>
</tr>
<tr>
<td></td>
<td>655</td>
<td>1965</td>
<td>635</td>
<td>1865</td>
</tr>
<tr>
<td></td>
<td>360</td>
<td>1335</td>
<td>490</td>
<td>1445</td>
</tr>
</tbody>
</table>
| **Dip [deg]**    | 85% < 10°       | 73% < 10°       | 76% < 10°       | 70% < 10°
Remaining Uncertainty

- Structure built from 2D seismic only – not complete picture

- Velocity model – additional well data can resolve issues

- Can Harvey 1 be considered ‘representative’
  - Excellent reservoir properties
  - High net-to-gross
  - Need to keep in mind that Harvey 1 could be conservative or optimistic
Dynamic Models

- Overall, the settings and general conditions for the dynamic modelling of the previous and current model align with each other.
- Differences include
  - Gridding
  - Fault properties
  - Relative permeabilities, endpoints and capillary effects
  - Well control and injection intervals
Gridding

- Grid orientation is different
- Greater vertical resolution in new grid
- Larger extent in new grid, less boundary condition effects
- More faults in new grid

Stage 1a/1b

Subsurface Modelling Update
Appraisal Program

- Three broad areas of investigation
  1. Overall permeability of geological system
  2. Degree of reservoir and pressure continuity across faults and strata
  3. Containment assurance without a conventional caprock

- At least two wells are needed
  1. Conduct water injection testing in the main fault block of the Area of Interest, that is in the same fault block as the Harvey 1 well, but in a structurally deeper position.
  2. Appraise the adjacent fault block to the north or south to verify the degree of hydraulic and stratigraphic continuity and to confirm injectivity in the Area of Interest.
New Wells

• The wells should:
  • Be located within the area of the 3D seismic survey. VSP data are required for optimal well-to-seismic tie.
  • Be close enough to a significant fault to gauge response to injection test
  • Collect vertical pressure interference data during injection test

• Additionally, they should
  • Allow sufficient core data collection
  • Measure pressure gradients and pore fluid sampling
  • Allow characterization through well loggings across formations of interest
New Wells

- New well could consider
  - An optional, small scale CO₂ injection test, followed by repeat logging
  - Drilling companion monitoring well nearby to directly measure injection test performance

- Several key appraisal points should be addressed in addition to routine model updates
  - Calibrate geomechanics study with XLOT
  - In depth stratigraphic and sedimentological study on size and quality of beds of sand, silt, and shale
  - Geochemistry of reservoir rocks and interaction with CO₂ saturated pore fluid
  - Consider other monitoring approaches for Area of Interest
Concluding Remarks

• Although data are still limited, no technical showstoppers can be identified.
• Several sections of this study are favourable to CO₂ injection
  • Good reservoir properties
  • High fracture gradient
  • Stable faults
  • Preliminary area-specific relative permeability curves suggesting higher residual trapping potential than in the previous study
• No new indicators that would suggest postponing or cancelling additional appraisal data acquisition plans
• Still critical uncertainties related to structure and trapping potential that need to be address before any final investment decision is made.