DESKTOP DESIGN STUDY ON ENHANCING RESIDUAL AND DISSOLUTION TRAPPING

FINAL REPORT

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Summary

This report presents the numerical reservoir simulation and economic modelling results of CO₂ injection options for the SW Hub Project. Both analyses are based on an updated static model developed by Schlumberger in 2013. The SW Hub Project is a government industry partnership led by the Western Australia Department of Mines and Petroleum. The industry partners include Alcoa Australia, Griffin Energy Developments, Perdaman Chemicals and Fertilisers, Electricity Generation Corporation (Verve) and Premier Coal Limited. In 2011, the SW Hub Project achieved a national flagship status to reduce greenhouse gas emissions in Australia.

The area is located structurally high in the shire of Harvey, north of Kemerton Industrial Estate and south of Mandurah. Injection rates are expected to change as the project progresses. They range from 0.05 million tonnes per year (Mt/yr) at the start to 6.5 Mt/yr. Schlumberger Carbon Storage Solutions estimated a total CO₂ storage capacity of between 200 and 260 Mt (Department of Mines & Petroleum 2012 & Schlumberger 2013).

The study aims to demonstrate a methodology for optimising the residual and dissolution trapping in the storage formation (the Lesueur Sandstone in Western Australia) by determining the most feasible injection schemes among various options. We understand that the in-situ rock and fluid properties are modelled based on the available data. We accept that there is some uncertainty in the data. However, we were asked to use the data provided and cannot change the data to maximise residual and dissolution trapping. Therefore, the only way to maximize the trapping mechanisms is to see the effects of different injection strategies, as described in this report.

Continuous CO₂ injection is usually preferred for carbon capture and storage (CCS) projects. However, the literature shows that this option does not necessarily maximise residual and dissolution trapping. For this reason, we considered several additional injection options. These include -

- (a) horizontal wells
- (b) simultaneous or alternating injection of CO₂ and water (SWAG or WAG),
- (c) injecting water pre-saturated with CO₂ (carbonated water),
- (d) pre-flushing the formation with low-salinity water and
- (e) diverting CO₂ into low-permeability regions through reservoir pressure management, fines migration or foam flooding.

Of the above options, we analysed only (a) and (b) for reasons discussed in the introduction.

We use the updated static model constructed by Schlumberger in a previous ANLEC contract for SW Hub Project. This model basically has 1,231,582 grids covering 3 different formations. The static model used is an updated version of the static model created by Schlumberger in 2011. It incorporates new ELAN (element analysis) data obtained from GSWA-Harvey-1 well and the seismic survey conducted in 2011. In addition, the two wells (Pinjarra-1 and Preston-1), which were used in the 2011 model, have undergone a more in depth petrophysical analysis by integrating core lab data. Schlumberger integrated all of the updated data into the new static model in 2012. As before, they generated various realisations of the static model. We were provided with a single static model to conduct our analysis. The model they
constructed honours their knowledge at the time. Final adjustments are only possible once all new data is incorporated (Schlumberger 2013). This model does not include data from the Fault Seal First-Order-Analysis (Langhi et. al 2013) and the recent seismic survey shot in 2014.

We use the Eclipse 300 Compositional Simulator with the CO2STORE option for reservoir simulations. We use 9 injection wells (based on Schlumberger’s dynamic simulations) for most of our scenarios and place injection wells between faults F1 and F10. We assume a group injection scheme that injects 0.05 Mt/yr for the first 2 years, 2.5 Mt/yr for the next 4 years and 6.5 Mt/yr for the last 34 years. Our simulations continue for 100 years after injection in order to monitor reservoir pressure and CO₂ migration.

Schlumberger previously conducted several sensitivity analyses in their dynamic simulation study. In addition, they utilised probabilistic Monte Carlo models to assess the specific likelihood of injectivity and rank remaining uncertainties. Before simulating injection, we conduct a sensitivity analysis to understand the contribution of uncertain reservoir parameters (unchangeable parameters). We then assess the different possible injection designs. From this analysis we make the conclusions below -

(a) Vertical grid refinement has an insignificant effect. However, areal grid refinement around injection wells gives a 12% increase in the cumulative CO₂ injected, fluctuations in residual trapping and a 7% decrease in dissolution trapping.
(b) Increasing the salinity from 48,000 ppm to 80,000 ppm would result in a 7% decrease in the cumulative CO₂ injected, an 8% increase in residual trapping and a 13% decrease in dissolution trapping.
(c) Compared to closed faults, open faults would lead to a 27% increase in the cumulative CO₂ injected. Open faults give a negligible increase in residual trapping and a 5% decrease in dissolution trapping.
(d) Doubling the absolute permeability of the entire storage formation would increase the cumulative CO₂ injected by 19%. It would increase residual trapping by 4% and decrease dissolution trapping by 3%.
(e) Different vertical well placements in the storage formation can give a 7% variation in the cumulative CO₂ injected, a 3% change in residual trapping and a 4% change in dissolution trapping.
(f) Introducing a high permeability streak would lead to a 3% increase in the cumulative CO₂ injected, a 1% change in residual trapping and a 3% increase in dissolution trapping.
(g) Activating the capillary pressure option leads to a 5% decrease in the cumulative CO₂ injected, a 1% increase in both residual trapping and a 2% increase in dissolution trapping.
(h) Introducing a low-permeability barrier between Yalgorup and Wonnerup formations would result in a 9% decrease in the cumulative CO₂ injected, a 1% decrease in residual trapping and a 1% decrease in dissolution trapping.
(i) Activating the salting-out option has almost no impact on the cumulative CO₂ injected and residual trapping. However, there is a 1% decrease in dissolution trapping.
(j) For the water production cases, we place water production wells in between the injection wells. This is to relieve pressure, which allows us to inject more cumulative CO₂. All the cases with a perforation interval equal
to or greater than 500 m inject the full 230 Mt of CO$_2$. However, CO$_2$ breakthrough for most cases occurs after roughly 8 years.

(k) WAG analysis shows that:
(1) Longer perforations increase CO$_2$ trapping and enable more injection,
(2) Injecting more water compared to CO$_2$ enhances dissolution trapping considerably,
(3) Of all of the engineering designs we examine, WAG wells enhance overall trapping the most, but
(4) The gain in dissolution trapping is offset by the loss of injectivity (yet, lost injectivity could be regained by producing water), and
(5) We test WAG with vertical water production wells at a given position, which leads to CO$_2$ production. Varying the positions of the water production wells may reduce cumulative CO$_2$ produced or potentially eliminate CO$_2$ production.

(l) SWAG encourages residual trapping and dissolution. This is because water and CO$_2$ flow in opposite directions. In addition, we force imbibition very early on and enhance diffusion. SWAG easily leads to CO$_2$ breakthrough and must be designed very carefully. Low permeability layers minimise contact between water and the CO$_2$ injected. As a result, SWAG might not be best suited for this type of reservoir.

Our simulations suggest that well sequencing does not significantly affect the cumulative CO$_2$ injected, nor residual and dissolution trapping.

We assess relative attractiveness of possible economic and trapping options. We do so by combining estimates of a project’s net present value (NPV) and its “trapping benefit index (TBI).” The NPV indicates the measurable monetary net benefits and costs of the project. The TBI compares the extent to which the CO$_2$ is trapped for each option.

The table below summarises the conclusions we make from our NPV and TBI analyses. Vertical wells are the most economically attractive, but show intermediate overall trapping benefit. WAG wells are the least economically attractive, but show the highest overall trapping benefit, especially early in the injection period.

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1. Introduction

1.1 SW Hub Project

The SW Hub Project is a government/industry partnership led by the Western Australia Department of Mines and Petroleum. The industry partners include Alcoa Australia, Griffin Energy Developments, Perdaman Chemicals and Fertilisers, Electricity Generation Corporation (Verve) and Premier Coal Limited. In 2011, the SW Hub Project achieved a national flagship status. It aims to reduce greenhouse gas emissions in Australia. The project involves capturing CO₂ from the exhaust gases of several industrial plants in WA, transporting it to an injection site and injecting the CO₂ into the Lesueur sandstone. There are 5 different injection stages during the project, these include -

- Preparation Phase
- Enabling Case
- Base Case
- Extended Case 1
- Extended Case 2

CO₂ injection rates are expected to change as the project progresses. They range from 0.05 million tonnes per year (Mt/yr) at the start to 6.5 Mt/yr at peak. Previous dynamic simulations conducted by Schlumberger, on the updated 2013 static model, estimate a total CO₂ storage of between 200 and 260 Mt (Department of Mines & Petroleum 2012 and Schlumberger 2013). The updated static model used by Schlumberger (and for our reservoir engineering analysis) does not include the new seismic survey shot in 2014 and data from the Fault Seal First-Order-Analysis (Langhi et. al 2013).

The storage formation is a saline aquifer in the Perth Basin and bounded by two main faults known as the Darling and Dunsborough faults. It is a NW-SE trending structural high known as the Harvey Ridge. This is in the shire of Harvey, north of the Kemerton Industrial Estate and south of Mandurah. The formation of interest was formed in the Triassic period and is called the Lesueur Formation. It lies 1.4 - 3 km in the subsurface and is divided into two main members. The upper member is known as the Yalgorup Member and the lower member is known as the Wonnerup Member (Department of Mines & Petroleum 2013). There is no known proven seal for this storage reservoir and trapping is mainly dependent on -

- Formation heterogeneity and inter/intra-formational baffles.
- Residual and dissolution trapping, which is expected to be high because of a larger contact area between injected CO₂ and in-situ brine, is caused by the thick Lesueur Formation. We can infer this from evidence in the current literature and industry knowledge.

Many major faults have been interpreted in the area of interest. However, not all faults have been identified because of the lack of data coverage. One of the regional fresh water aquifers (Yarragadee Formation) is absent; while the other fresh water aquifer (Leederville Formation) is present above the area of interest. Hence this reduces the risk of fresh water contamination by CO₂ (Van Gent & Stalker 2010).
1.2 Trapping Mechanisms

1.2.1 Residual & Dissolution Trapping

Residual and dissolution trapping are key ways to immobilise the injected CO₂ in a carbon capture and storage (CCS) project. We need to maximise both types of trapping in order to minimise containment-related risks. Although both depend strongly on how injected gas contacts formation water, their trapping processes are different. The contact of injected CO₂ with formation water initiates dissolution trapping instantaneously. This may trap a significant amount of gas depending on pressure, temperature and water salinity. The dissolution trapping process continues for a long time. It first starts through diffusion-based dissolution and later continues through convective-mixing-based dissolution. Residual trapping requires imbibition of formation water so that some of the CO₂ can be trapped by capillary forces. This is called “snap-off”. Both dissolution and residual trapping mechanisms interact with each other, making modelling both phenomena very complex. Hence, if a CCS project is to be designed properly, engineers need to understand the interplay between these trapping mechanisms thoroughly. Furthermore, the static model must adequately reflect the in-situ rock properties that are upscaled by the engineers.

1.2.2 Trapping Efficiency

Trapping efficiency depends on the degree of contact between injected CO₂ and water. Hence, the injection well design becomes extremely important in maximising both residual and dissolution trapping. One of the challenges in a CO₂ storage formation is that CO₂ can bypass low-permeability regions during the injection period. This reduces the contact area between water and CO₂. One solution is to divert the injected CO₂ flow by creating engineering sinks in the storage formation (through water producers, for example).

1.2.3 Trapping Sensitivity

From the numerous papers we have reviewed (see the list of references), our main conclusions are below.

- As reservoir pressure increases, residual trapping and dissolution increases.
- As salinity increases, dissolution trapping decreases.
- As temperature increases, dissolution decreases.
- A thick reservoir allows the CO₂ plume to migrate upwards, contacting more fresh brine. This allows more residual and dissolution trapping to occur. This can be achieved by injecting CO₂ at the bottom of the reservoir.
- Larger contact between injection well and reservoir has the potential to increase dissolution trapping.
- Decreasing perforation interval length can lead to a more uniform CO₂ plume, which results in a greater amount of residually trapped and dissolved CO₂.
- Heterogeneous reservoirs tend to increase both dissolution and residual trapping of CO₂ as they spread injected gas more within the formation.
- Increasing horizontal permeability leads to a greater lateral spreading of the plume, which increases dissolution trapping. Horizontal injection velocity plays an important role in the plume shape, which affects both residual and dissolution trapping. The higher the horizontal injection velocity, the more residual trapping is possible.
• Low-salinity water injection accelerates both dissolution and residual trapping. This is because water injection enhances both diffusion and imbibition.
• A lower ratio of vertical to horizontal permeability in the reservoir leads to higher dissolution trapping. This gives a disc-shaped CO₂ plume which enhances the contact between CO₂ and brine.
• Refining grids significantly improves our ability to model the cumulative injected CO₂ and both trapping mechanisms in the short-run.

1.3 Aim of Study

In this project, we carry out a techno-economic analysis of residual and dissolution trapping for the SW Hub Project. We aim to analyse the engineering and economic effects of several injection schemes on residual and dissolution trapping. Some injection schemes and processes such as foam injection, carbonated water injection and fines migration were ruled out early on because they are believed to be extremely costly. As a result, the options we analyse include -

• Vertical injection wells
• Horizontal injection wells
• Vertical injection wells and production wells for pressure relief
• Water Alternate Gas (WAG) wells and production wells for pressure relief
• Simultaneous Water Alternate Gas (SWAG) engineering design proposed by Anchilya & Ehlig-Economides (2009)

We perform numerical reservoir simulations using Schlumberger’s Compositional Simulator (E-300) to analyse the degree of residual and dissolution trapping. We adapt the Killough trapping model to assess the residual trapping. We examine the effects of well type, location and spacing, perforation height and location. In addition, except for the last scheme (SWAG), we analyse the economics of each injection scheme to show the relative economic attractiveness of each scheme. We do not analyse the economics of the SWAG scheme because the engineering results were not encouraging.

We agreed during a teleconference call on the 24th of September 2013 to carry out 29 simulations runs. Later this was increased to 60 simulation runs for a better understanding and analysis of the reservoir. Table 1-1 shows the list of simulation cases.

The outcomes of this study include -

(1) To determine the degree of residual and dissolution trapping for a range of injection schemes.

(2) To develop a techno-economic approach that can be used to assess the relative engineering and economic attractiveness of different injection schemes.
Table 1-1: List of cases performed for our analysis

<table>
<thead>
<tr>
<th>Priority</th>
<th>Closed faults</th>
<th>No. of simulations</th>
<th>Completed</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Teleconference Proposed Simulations</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>Base Case (Schlumberger case)</td>
<td>1</td>
<td>YES</td>
</tr>
<tr>
<td>1</td>
<td>Sensitivity analysis of faults</td>
<td>2</td>
<td>YES</td>
</tr>
<tr>
<td>1</td>
<td>Barrier between Wonnerup and Yalgorup</td>
<td>1</td>
<td>YES</td>
</tr>
<tr>
<td>1</td>
<td>High-perm streaks (open &amp; closed faults)</td>
<td>2</td>
<td>YES</td>
</tr>
<tr>
<td>1</td>
<td>Salting out effect</td>
<td>3</td>
<td>YES</td>
</tr>
<tr>
<td><strong>Newly requested simulations (24th Sept.)</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>Permeability sensitivity for the whole reservoir</td>
<td>1</td>
<td>YES</td>
</tr>
<tr>
<td>2</td>
<td>Identifying potential positions for slim-holes</td>
<td>~</td>
<td>YES (not in report)</td>
</tr>
<tr>
<td><strong>Agreed Simulations</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>Well placement strategies for vertical wells</td>
<td>6</td>
<td>YES</td>
</tr>
<tr>
<td>3</td>
<td>Well placement strategies for vertical wells with local grid refinement</td>
<td>6</td>
<td>YES</td>
</tr>
<tr>
<td>3</td>
<td>Local grid refinement sensitivity</td>
<td>7</td>
<td>YES</td>
</tr>
<tr>
<td>3</td>
<td>Capillary pressure test (J-function &amp; Brooks-Corey / Van Genuchten)</td>
<td>2</td>
<td>YES</td>
</tr>
<tr>
<td>3</td>
<td>Sequence of wells brought online</td>
<td>4</td>
<td>YES</td>
</tr>
<tr>
<td>3</td>
<td>Optimising vertical wells</td>
<td>5</td>
<td>YES</td>
</tr>
<tr>
<td>4</td>
<td>Optimising horizontal wells</td>
<td>5</td>
<td>YES</td>
</tr>
<tr>
<td>4</td>
<td>Optimising vertical wells with water producers</td>
<td>5</td>
<td>YES</td>
</tr>
<tr>
<td>5</td>
<td>Optimising WAG with water producers</td>
<td>5</td>
<td>YES</td>
</tr>
<tr>
<td>5</td>
<td>Optimising SWG with water producers</td>
<td>5</td>
<td>YES</td>
</tr>
</tbody>
</table>
2. Reservoir Engineering Methodology

2.1 Static Model Description

The Schlumberger static model, which we used for our simulations, has properties (such as permeability and porosity) derived from three main wells. These wells are Pinjarra-1, Lake Preston-1 and Harvey-1. We focus on injection in the Wonnerup Member. The lithology data obtained from these wells show that the Lesueur Sandstone (Wonnerup Member) contains several very low permeability layers (short - intermediate lateral continuity). All three wells used to build this model have severe wash-out sections. This is probably due to highly stressed intervals or because these sections contain shale, claystone or siltstone sections. Furthermore, these wells report the presence of inter-bedded shale or claystone, shale streaks or baffles and silt in the Lesueur Formation (Schlumberger 2013). All these have a very low permeability and would restrict pressure dissipation, causing a reduction in injectivity.

The Schlumberger Model contains only three different types of facies. These include (Schlumberger 2013):

- Sandstone
- Siltstone (relatively lower permeability than sandstone)
- Shale (these have very low permeability in the model and act as baffles or local barriers between sand and silt units)

The static model used is an updated version of the static model created by Schlumberger in 2011. It incorporates new ELAN (element analysis) data obtained from GSWA-Harvey-1 well and the seismic survey conducted in 2011. In addition, the two wells (Pinjarra-1 and Preston-1), which were used in the 2011 model, have undergone a more in depth petrophysical analysis by integrating core lab data. All of the updated data have been integrated into the new static model developed by Schlumberger in 2012. As before, various realisations of the static model were generated. We were provided with a single static model to conduct our analysis. The model constructed honours the present knowledge. For our simulations, we assume our model has closed boundaries (no infinite aquifer present). However, final adjustments are only possible once all new data is incorporated (Schlumberger 2013). This model does not include data from the Fault Seal First-Order-Analysis (Langhi et al 2013) and the recent seismic survey shot in 2014.

Figure 2-1 shows a cross-sectional picture of the reservoir. Figure 2-2 shows permeability pictures of a few layers above layer 56. The grey colours represent a vertical permeability of about 0.0001 mD (these represent the shale baffles). The dark blue colours represent a vertical permeability below 1 mD.

A summary of our base case’s main parameters are seen in Appendix A, Table 8-1 and the relative permeability curves are shown in Figure 8-1.
Figure 2-1: Cross-sectional view of the reservoir
Figure 2-2: Several layers that show areas of very low permeability (grey) in the reservoir. Permeability shown is for the X & Y directions.
2.2 Modifications

The starting point for our analysis is altering the Schlumberger model’s parameters so that it reflects the actual reservoir parameters. The changes to the model include:

- We set the maximum bottomhole pressure (BHP) for each well to be 90% of the formation fracture pressure (0.186 bars/m) at the well’s top most perforation. This is similar to the pressure that Schlumberger (2013) used for their maximum well BHP. We use the following equation:

\[ Z = 0.9 \times 0.186(x) \]

where \( Z \) is the maximum BHP (bars)
\( X \) is the depth of the shallowest perforation of the well (meters)

- We change the group injection rate of all the wells to follow the proposed injection rates and total (between 200 - 260 Mt of supercritical CO\(_2\)) in the Schlumberger Subsurface Modelling Update Report (2013) and the Department of Mines and Petroleum Report (2012). The applied injection scheme lasts for a total of 40 years and can inject a maximum total of 231 Mt of supercritical CO\(_2\) at roughly 5.8 Mt/yr. The injection rates specified are set out below.

  - The Enabling Case. This case injects a total of 0.05 Mt/yr for a period of 2 years.
  - The Base Case. This case injects a total of 2.5 Mt/yr for a period of 4 years.
  - The Extended Case. This case injects a total of 6.5 Mt/yr for a period of 34 years.
  - The Observation Phase. This period is used to observe the behaviour of the plume for 100 years after injection stops. According to Schlumberger (2013), it is during this time that the most significant plume changes take place.

- We change the aquifer salinity from the initial 19,000 ppm to 48,000 ppm. This salinity is a better reflection of the actual salinity in the reservoir. According to Schlumberger (2013), the salinity of the sandy sections observed by drilling Harvey-1 is between 50,000 - 60,000 ppm. However, this drops to between 20,000 - 25,000 ppm in the non-washed out shale areas. Since we are injecting in a mostly sandy area, with the presence of a few shale baffles, we chose a high average estimate of 48,000 ppm.

- We set all the faults’ transmissibilities specified in the model to zero. We agreed during the Technical Presentations in Perth on October 4 that all faults would be closed during simulation runs. This is because most of the main faults are not likely to be reactivated. In addition, all of the main faults possess a shale-gouge-ratio (SGR) greater than the empirical threshold (Langhi et. al. 2013). An SGR greater than 20% would result in a hydrocarbon sealing fault (Yielding 2003). However, as stated, this empirical threshold is for hydrocarbons and not supercritical CO\(_2\). Hence a more detailed study of the faults’ sealing capabilities towards supercritical CO\(_2\) may be required.
2.3 Well Number & Injection Area

From this point onwards, we use only 9 wells out of the total 12 wells available in the Schlumberger model. This is because the three additional wells are located beyond the two major faults F1 and F10. We were asked not to place any wells beyond these faults. If we use only 9 wells with all open faults, or 12 wells with all closed faults, we would be able to inject very close to the full amount specified. By analysing 9 wells we would be able to see which parameters would decrease or increase the cumulative injected CO$_2$. Comparing residual trapping and dissolution trapping for a 9 well injection scheme and for a 12 well injection scheme would not be a fair comparison. This is because the cumulative plume surface area would be different.

Figure 2-3 below shows the injection area between faults F1 and F10. Adopting this area was agreed during a teleconference on the 24$^{th}$ of September 2013 and reconfirmed during Technical Workshop on the 4$^{th}$ of October in Perth.

Figure 2-3: Area between faults F1 and F10, where injection is focused. The units of the scale are in metres.
3. Engineering Sensitivity Analysis

3.1 Fault Sensitivity

The first analysis we conduct on the Schlumberger model is a fault sensitivity analysis. We test 3 different scenarios -

- Open faults (all fault transmissibilities are set to 0 cP.m³/day.bar).
- Semi-open faults (all fault transmissibilities are set to 0.5 cP.m³/day.bar).
- Closed faults (all fault transmissibilities are set to 1 cP.m³/day.bar).

We observe in Figure 9-1 of Appendix B that the higher the transmissibility of the faults, the higher the CO₂ injection rate, which eventually results in a higher cumulative amount of CO₂ injected. Figure 9-2 and 3 (Appendix B) shows that with closed faults, the BHP of well 10 remains at maximum and does not change. As a result, the mass rate of CO₂ falls in order to prevent the BHP from rising higher than the allocated maximum BHP. On the other hand, for both open and semi-open faults, BHP is below the maximum allocated BHP. This enables the wells to inject at the full rate. The reasons are that compared to open and semi-open faults, closed faults reduce the effective storage volume and pressure is unable to dissipate as easily.

Referring to Table 3-1, we can see that the differences between the open and semi-open fault cases are insignificant. Therefore we only compare the differences between closed and open fault cases. We notice that the percentage of residually trapped CO₂ increases slightly when faults are open. This is because a larger CO₂ plume volume is achieved. As a result, a larger swept area that has residual CO₂ is left behind as the plume migrates upwards. However, the percentage of dissolved CO₂ decreases for open faults. This is because of the “smaller surface area to volume ratio” of the plume (or the distance between supercritical CO₂ interface and brine). In addition, because the pressure of the aquifer rises rapidly in the closed faults, this leads to more dissolved CO₂ (Chang et. al 1996 and Takasawa et. al. 2010).

Table 3-1: Summary of results for fault sensitivity after 100 years of observation (for graphs, refer to Appendix B, Figures 9-4,5 and 6)

<table>
<thead>
<tr>
<th>Case type</th>
<th>CO₂ state (Mass %)</th>
<th>Cumulative CO₂ injected (Mt)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Trapped (Mt)</td>
<td>Dissolved (Mt)</td>
</tr>
<tr>
<td>Closed faults (Base Case)</td>
<td>98.4 (54.6%)</td>
<td>58.3 (32.4%)</td>
</tr>
<tr>
<td>Semi-open faults</td>
<td>125.2 (54.8%)</td>
<td>70.6 (30.9%)</td>
</tr>
<tr>
<td>Open faults</td>
<td>125.4 (54.8%)</td>
<td>70.7 (30.9%)</td>
</tr>
</tbody>
</table>
3.2 Barrier between Wonnerup and Yalgorup Formations

We also test the effects of an impermeable shale barrier between the Wonnerup and Yalgorup Formations. We test this by making the grid blocks between layers 40 - 50 null blocks (see Figure 3-1). Table 3-2 shows these layers are part of the Wonnerup Top Formation in the dynamic model.

From Figure 10-1 in Appendix C, we see that the presence of a barrier between the two formations reduces the amount of cumulative supercritical CO₂ injected. This is because the barrier at the top acts like a sealing fault, which reduces the effective volume available for CO₂ storage. In addition, because the volume in a closed barrier is reduced, pressure cannot dissipate as easily (see the fault analysis in Section 3.1). We see evidence of this in Figures 10-2 and 10-3 (Appendix C), where the BHP of well 10 for both cases is at a maximum. However, for the barrier case, we observe a faster drop in injection rate in order to remain below the maximum allocated BHP for well 10.

Table 3-2: The different layers in the Schlumberger dynamic model. The highlighted Wonnerup Top Zone is impermeable in this analysis (personal communication with Sandeep Sharma and Giovanni Sosio of Schlumberger, 2013)

<table>
<thead>
<tr>
<th>Formation name</th>
<th>Zones (K-layers)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Yalgorup Top</td>
<td>1-5</td>
</tr>
<tr>
<td>Yalgorup 1</td>
<td>6-10</td>
</tr>
<tr>
<td>Yalgorup 2</td>
<td>11-20</td>
</tr>
<tr>
<td>Yalgorup 3</td>
<td>21-35</td>
</tr>
<tr>
<td>Wonnerup Top</td>
<td>36-50</td>
</tr>
<tr>
<td>Wonnerup 1</td>
<td>51-64</td>
</tr>
<tr>
<td>Wonnerup 2</td>
<td>66-102</td>
</tr>
<tr>
<td>Wonnerup 3</td>
<td>107-122</td>
</tr>
<tr>
<td>Wonnerup 4</td>
<td>124-163</td>
</tr>
<tr>
<td>Sabina Sandstone</td>
<td>186</td>
</tr>
<tr>
<td>Willespie Top/Sabina Base</td>
<td>187</td>
</tr>
</tbody>
</table>
Table 3-3 shows that the percentage of both residually trapped and dissolution trapped CO₂ are slightly less for the barrier case. This is because the barrier above restricts the CO₂ plume from rising up and leaving a trail of trapped CO₂ behind. In addition, compared to the case without a barrier, the barrier gives the CO₂ plume has a smaller contact surface area. The deeper the perforation location or and the thicker reservoir, the further the vertical distance the plume can travel. This benefits both residual and dissolution trapping mechanisms (Kumar et. al 2005 & Sifuentes et. al 2009).
3.3 High Permeability Streaks

High permeability streaks in the reservoir alter the plume geometry, which changes the percentage residual and dissolution trapping. We select a single layer (z = 85) in which the horizontal permeability is varied (see Figure 3-2). We try out three different scenarios, namely-

- Base Case (where no high permeability streak is present).
- 10x Permeability Streak (where the layer 85's horizontal permeability is multiplied by a factor of 10).
- 100x Permeability Streak (where the layer 85's horizontal permeability is multiplied by a factor of 100).

From the results in Table 3-4, we inject a higher amount of cumulative supercritical CO$_2$ because the horizontal permeability is higher. In addition, we see that with higher permeability streaks, the percentage of dissolved CO$_2$ increases. This is because lateral spreading of the plume is larger (Stifuentes et. al 2009). This can be seen in Appendix D Figures 11-1 to 11-3. There is a small fluctuation in the percentage of residually trapped CO$_2$ because it competes with dissolution trapping (Nghiem et. al 2009). Hence, an increase in dissolution would tend to decrease the residually trapped CO$_2$.

Table 3-4: Summary of results for high permeability streaks after 100 years of observation (for graphs, refer to Appendix D, Figures 11-4 to 11-7)

<table>
<thead>
<tr>
<th>Case type</th>
<th>CO$_2$ state (Mass %)</th>
<th>Cumulative CO$_2$ injected (Mt)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Trapped (Mt)</td>
<td>Dissolved (Mt)</td>
</tr>
<tr>
<td>Base Case</td>
<td>98.4 (54.6%)</td>
<td>58.3 (32.4%)</td>
</tr>
<tr>
<td>10x Perm Streak</td>
<td>101.7 (54.9%)</td>
<td>61.5 (33.2%)</td>
</tr>
<tr>
<td>100x Perm Streak</td>
<td>100.2 (54.0%)</td>
<td>62.1 (33.5%)</td>
</tr>
</tbody>
</table>
3.4 Salting-out

Salting-out occurs in conjunction with drying-out. It happens when we inject a dry gas at a high rate into a saline aquifer. The movement of the dry fluid over brine causes water to vaporise, which may reduce the irreducible water saturation to zero. As drying-out continues, the salinity of the aquifer around the perforation and the density of the brine continue to increase. Eventually the surrounding brine becomes supersaturated with salts. These salts will gradually precipitate and reduce the porosity and permeability of the formation surrounding the well perforation. As a result, these salt particles may block certain pore throats, compromising injectivity (Hurter et. al 2007).

We test out 4 different cases showing the effects of salting out in the reservoir, these include-

- Base Case (salinity of 48,000 ppm, with salting-out disabled)
- Base Case with salting-out (salinity of 48,000 ppm)
- 80,000 ppm salinity (with salting-out disabled)
- 80,000 ppm salinity with salting-out

When activating the salting-out option, we used a solid mobility multiplier for Viking Sandstone of Alberta Basin in Canada which is seen in Figure 3-3.

Table 3-5 shows that as salinity increases, the percentage of dissolved CO\textsubscript{2} decreases. This phenomenon is reported by Chang et. al (1996), Duan et. al. (2003), Stifuentes et. al (2009), Nghiem et. al (2009) and Takasawa et. al (2010). In contrast, the percentage of residually trapped CO\textsubscript{2} increases with increasing salinity. This is because the density of the aquifer increases, which results in a higher hydrostatic pressure. As a result of the increased pressure, the CO\textsubscript{2} plume becomes less mobile, which enhances residual trapping (Stifuentes et. al 2009). In addition, because the hydrostatic pressure is higher, the pressure difference between initial injection
pressure and maximum BHP pressure is smaller. This means that we inject at a lower rate in a high salinity aquifer compared to that of a low salinity aquifer. Therefore, we inject a lower cumulative amount of supercritical CO₂. This reduction in injectivity is reported by Alkan et. al (2009).

When comparing between salting-out and no salting-out, we observe that the percentage of residually trapped CO₂ increases because of salt precipitation around some of the perforation interval. As a result, imbibition will occur around the area where salt has precipitated, resulting in a higher amount of residually trapped CO₂. On the other hand, the percentage of dissolved CO₂ decreases with salting-out because of the smaller contact area between brine and CO₂. The Figures in Appendix E show the dissolved CO₂ vs. time for the 4 cases. However, it does not show the other graphs because they look almost identical.
Table 3-5: Summary of results for salting-out after 100 years of observation (Figures 12-1 and 12-2 in Appendix E)

<table>
<thead>
<tr>
<th>Case type</th>
<th>CO₂ state (Mass %)</th>
<th>Cumulative CO₂ injected (Mt)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Trapped (Mt)</td>
<td>Dissolved (Mt)</td>
</tr>
<tr>
<td>Base Case (no salting-out)</td>
<td>98.4 (54.6%)</td>
<td>58.3 (32.4%)</td>
</tr>
<tr>
<td>Base Case (with salting-out)</td>
<td>98.7 (54.8%)</td>
<td>57.8 (32.1%)</td>
</tr>
<tr>
<td>80,000 ppm (no salting-out)</td>
<td>98.8 (58.7%)</td>
<td>47.3 (28.1%)</td>
</tr>
<tr>
<td>80,000 ppm (with salting-out)</td>
<td>99.0 (59.0%)</td>
<td>46.6 (27.8%)</td>
</tr>
</tbody>
</table>

3.5 Absolute Permeability

We also examine the sensitivity to changes in absolute permeability. We change the absolute permeability of the entire dynamic model to observe the effects on the plume, cumulative CO₂ injected, residual and dissolution trapping. We analyse two different scenarios:

- Base Case (where average absolute permeability of the reservoir is 23.5 mD)
- Abs. Perm X2 (where average absolute permeability is doubled to 47 mD)

A summary of the results is presented in Table 3-6 below. The results show that a higher permeability increases the cumulative amount of supercritical CO₂ injected. This is because the pressure can dissipate and the plume can spread out more easily. The explanation in section 3.1 of this report also applies here. We also notice that residual trapping increases because the plume volume is larger, allowing a larger trail of residually trapped CO₂ to be left behind the plume's upward movement. In contrast, we observe a slight reduction in the amount of dissolved CO₂. This is because of the “smaller surface area to volume ratio” of the (or distance between supercritical CO₂ interface and brine) (see Section 3.1). Another reason for the percentage decrease in dissolved CO₂ is that there are several very low permeability layers between the Lower Lesueur and Upper Lesueur which cause the plume layers to spread. Since the Abs. Perm X2 case contains a higher absolute permeability compared to the Base Case, the plume rises faster and is able to spread out beneath these extremely low permeability layers. Although there is an increase in surface area, these extremely low permeability layers, just above where the plume accumulates, slow down the rate of diffusion. This is because the low permeability is low, and there is less connection between the CO₂ and brine (see Figure 13-1 Appendix F).
Table 3-6: Summary of absolute permeability test after 100 years of observation (Figures 13-2 to 13-6, Appendix F)

<table>
<thead>
<tr>
<th>Case type</th>
<th>CO₂ state (Mass %)</th>
<th>Cumulative CO₂ injected (Mt)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Trapped (Mt)</td>
<td>Dissolved (Mt)</td>
</tr>
<tr>
<td>Base Case</td>
<td>98.4 (54.6%)</td>
<td>58.3 (32.4%)</td>
</tr>
<tr>
<td>Abs. Perm X2</td>
<td>122.1 (56.8%)</td>
<td>67.7 (31.5%)</td>
</tr>
</tbody>
</table>

3.6 Model Cropping

Since no CO₂ can migrate across the closed faults, the grid blocks beyond the closed faults are of no use. Furthermore, we need to inject supercritical CO₂ between faults F1 and F10 as was agreed on during a teleconference in September. As a result, we remove these grids to save simulation computational time.

The new cropped model would have the same total effective pore volume as a closed fault Schlumberger model. The new cropped model consists of (66 x 73 x 187) 900,966 grids compared to the (89 x 74 x 187) 1,231,582 grids of the Schlumberger Model. Figure 3-4 below shows the Schlumberger model and the cropped model for comparison.

In order to validate the results of the two models, we test out a single injection scheme and observe the results from both models. We apply an injection scheme known as Base Vertical Well Placement (Base VWP). The well positions of Base VWP are exactly the same as the Schlumberger well placement recommended in Schlumberger Report 1.1 (2013). However, the perforation intervals are just 500 m, instead of between 600 - 750 m. Table 3-7 below shows a comparison of the results between the two models, while the Figures (14-1 to 14-4) are in Appendix G. The results show that there is a very small mass difference between the two models. In addition, Figure 14-5 in Appendix G shows that the cropped model cuts down the simulation computational time by roughly 60%. Therefore, in order to be more time efficient, we work only with the cropped model from this point.
**3.7 Capillary Pressure Analysis**

We also test out the effects of capillary pressure. Alkan et. al (2010) mention that inserting capillary pressures into the model would result in a faster increase in BHP, reducing the mass rate of supercritical CO\textsubscript{2} injected throughout the lifetime of the project. Since no capillary pressures are provided, we generate our own using several equations found in literature. This section emphasises the importance of capillary pressure in the dynamic simulation model.

For our capillary pressure analysis we apply two difference techniques -

- Brooks-Corey / Van Genuchten
- J-Leverett Function
3.7.1 **Brooks-Corey / Van Genuchten**

For this technique, a single capillary pressure curve is generated for the drainage process and a single capillary pressure curve is generated for the imbibition process. This is applied to all the grid blocks present in the static model.

### 3.7.1.1 Brooks-Corey Equation

We use the Brooks-Corey model for our drainage capillary pressure curve. The equations we apply are (Brooks & Corey 1960):

\[
P_{cD} = P_{ct} S_w^{\frac{1}{\lambda}} \\
S_{wd} = \frac{S_w - S_{wr}}{1 - S_{wr}}
\]

Where,
- \( P_{cD} \) is the drainage capillary pressure (bars)
- \( P_{ct} \) is the threshold capillary pressure (bars)
- \( S_{wd} \) is the drainage water saturation (dimensionless)
- \( \lambda \) is the pore size distribution index (dimensionless)
- \( S_w \) is the water saturation (dimensionless)
- \( S_{wr} \) is the residual water saturation (dimensionless)

The pore size distribution index (\( \lambda \)) is a representation of the reservoir heterogeneity, which is usually 1 - 5. A high value of (\( \lambda \)) means that the porous media is less heterogeneous (Li 2004).

### 3.7.1.2 Van Genuchten Equation

In addition, we generate a single capillary pressure curve for the imbibition process, which is also applied to all the grid blocks present in the static model. We use the following equations below (Van Genuchten 1980):

\[
P_{ci} = P_{ct} \left( S_w^{\frac{1}{m}} - 1 \right)^{1-m} \\
S_{wi} = \frac{S_w - S_{wr}}{1 - S_{wr} - S_{gr}}
\]

Where,
- \( P_{ci} \) is the imbibition capillary pressure (bars)
- \( P_{ct} \) is the threshold capillary pressure (bars)
- \( S_{wi} \) is the imbibition water saturation (dimensionless)
- \( m \) is the Van-Genuchten fitting parameter (dimensionless)
- \( S_w \) is the water saturation (dimensionless)
- \( S_{wr} \) is the residual water saturation (dimensionless)
$S_{gr}$ is the residual gas saturation (dimensionless)

### 3.7.1.3 Threshold Capillary Pressure Equation

In order to derive the threshold capillary pressure for each of the processes, we use a simple equation provided by Thomas & Katz (1968):

$$P_{ct} = 7.37 \times \left( \frac{1}{k} \right)^{0.43}$$

Where, $k$ is the average permeability of the reservoir (mD)

$P_{ct}$ is the threshold capillary pressure (psi)

Table 3-8 shows the parameters we use to generate the capillary pressure curves. The pore size distribution index and the Van Genuchten fitting parameters are assumed for this analysis. A more in-depth analysis of these two parameters is required to generate capillary pressure curves that represent the reservoir more accurately.

**Table 3-8: Parameters used for generating Brooks-Corey / Van Genuchten capillary pressure curves**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average permeability (k)</td>
<td>18.4 mD (average of both horizontal and vertical permeability obtained from Petrel)</td>
</tr>
<tr>
<td>Threshold capillary pressure (P_{ct})</td>
<td>0.145 bars</td>
</tr>
<tr>
<td>Residual water saturation (S_{wr})</td>
<td>0.454 (Schlumberger 2013)</td>
</tr>
<tr>
<td>Residual gas saturation (S_{gr})</td>
<td>0.370 (Schlumberger 2013)</td>
</tr>
<tr>
<td>Pore size distribution index (λ)</td>
<td>1</td>
</tr>
<tr>
<td>Van Genuchten fitting parameter (m)</td>
<td>0.4</td>
</tr>
</tbody>
</table>

### 3.7.2 J-Leverett Function

In this method, a single J-function curve is generated using the drainage capillary pressures derived by the Brooks-Corey method. A separate J-function is generated using the imbibition capillary pressures derived by the Van Genuchten method. These J-function values are incorporated in the dynamic simulator where drainage and imbibition capillary pressure curves are calculated for each individual grid block.
3.7.2.1  J-Leverett Equation

The equation for the J-Leverett capillary pressure function (Satter et. al 2008):

\[
J(S_w) = \frac{C P_c}{\sigma \cos \theta} \sqrt{\frac{k}{\phi}}
\]

Where,

\(J(S_w)\) is the J-function value at a specific water saturation

C is a constant for unit conversion (0.21645)

k is the average permeability (18.4 mD)

\(\theta\) is the wetting angle (taken to be fully water-wet at 0°)

\(\phi\) is the average porosity (0.10, obtained from Petrel)

\(\sigma\) is the surface tension (assumed to be 30 mN/m)

\(P_c\) is the capillary pressure values taken from Brooks-Corey / Van Genuchten

After generating the appropriate capillary pressures and J-functions, we compare the results with our base case (which does not include any capillary pressures). A summary of the results are shown below in Table 3-9. We observe that incorporating capillary pressures into the dynamic simulations reduces the cumulative supercritical CO\(_2\) injected, as reported by Alkan et. al (2010). Residually trapped CO\(_2\) increases because capillary pressure reduces the ease in which the non-wetting fluid (CO\(_2\)) can pass through the wetting fluid (brine). Dissolution trapping increases because capillary forces reduce the gravity effects slightly, improving lateral movement throughout the reservoir, exposing the CO\(_2\) to a larger surface area of brine (Alkan et. al 2010). Different types of capillary pressure models would greatly affect the dissolution; mainly in the long run. It was reported that that Van-Genuchten type curves tend to accelerate dissolution greatly. Furthermore, dissolution is very sensitive to the steepness of the capillary pressure curve around the entry-slope region (Li et. al. 2013). Therefore, capillary pressures should be generated from proper laboratory analysis. This would provide more realistic long term simulation results.

Table 3-9: Summary of results for capillary pressure analysis after 100 years of observation (Appendix H Figures 15-1 to 15-4)

<table>
<thead>
<tr>
<th>Case type</th>
<th>CO(_2) state (Mass %)</th>
<th>Cumulative CO(_2) injected (Mt)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Trapped (Mt)</td>
<td>Dissolved (Mt)</td>
</tr>
<tr>
<td>Base Case</td>
<td>98.4 (54.6%)</td>
<td>58.3 (32.4%)</td>
</tr>
<tr>
<td>Brooks-Corey / Van Genuchten</td>
<td>96.3 (55.3%)</td>
<td>57.5 (33.0%)</td>
</tr>
<tr>
<td>J-Leverett Function</td>
<td>94.7 (55.1%)</td>
<td>57.0 (33.2%)</td>
</tr>
</tbody>
</table>
3.8 Vertical Well Placement

The main purpose of our vertical well placement scenarios is to increase the amount of cumulative supercritical CO$_2$ stored in the reservoir. These scenarios as designed to find the best possible injection sites to inject in the 200 - 260 Mt range specified by DMP (2012). These scenarios are not intended for field development; such a study would require extensive research. We apply the following steps when identifying appropriate injection sites -

1. We start with our Base VWP positions (same well locations as those reported by Schlumberger (2013), but different perforation length) and observe the performance of each well.
2. We shift the positions of a few bad performing wells to areas of relatively higher permeability. This is to allow for better injectivity and plume spread (see section 9 for an explanation of why we do this). The new well positions are called VWP 1.
3. We run VWP 1 and observe the performance of each well.
4. Again, we shift the positions of a few bad performing wells to areas of relatively higher permeability. The new well positions are called VWP 2.
5. We repeat this process until we reach VWP 5.

The total perforation interval for all wells is roughly 500 m instead of the perforation interval range of 600 - 750 m reported by Schlumberger (2013). In addition, we ensure that the top of the perforation interval contains 2 grid blocks in the Upper Wonnerup formation. An example of this is depicted in Figure 3-5.

Figure 16-1 in Appendix I shows the well positions for each vertical well placement scenario. Furthermore, Figures 16-2 to 16-21 in Appendix I compare the results between each vertical well placement scenario and the Base VWP. Table 3-10 shows a summary of the results comparing the six vertical well placement scenarios.

![Figure 3-5: Perforation interval location of well CO2_16, for Base VWP](image-url)
Table 3-10: Summary of results for vertical well placement scenarios after 100 years of observation (Appendix I Figures 44-2 to 44-21)

<table>
<thead>
<tr>
<th>Case type</th>
<th>CO2 state (Mass %)</th>
<th>Cumulative CO2 injected (Mt)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Trapped (Mt)</td>
<td>Dissolved (Mt)</td>
</tr>
<tr>
<td>Base Case</td>
<td>101.9 (54.1%)</td>
<td>55.8 (29.6%)</td>
</tr>
<tr>
<td>VWP 1</td>
<td>96.2 (53.5%)</td>
<td>54.0 (30.0%)</td>
</tr>
<tr>
<td>VWP 2</td>
<td>94.6 (52.6%)</td>
<td>52.7 (29.3%)</td>
</tr>
<tr>
<td>VWP 3</td>
<td>101.3 (53.0%)</td>
<td>58.7 (30.7%)</td>
</tr>
<tr>
<td>VWP 4</td>
<td>105.7 (53.3%)</td>
<td>60.9 (30.7%)</td>
</tr>
<tr>
<td>VWP 5</td>
<td>105.4 (52.5%)</td>
<td>61.0 (30.4%)</td>
</tr>
</tbody>
</table>

VWP 5 injects the highest amount of cumulative supercritical CO2 into the formation. In addition, residually trapped CO2 and dissolution trapped CO2 changes (approximately a 2% change) when vertical well positions are changed. This is because different well placement positions have different surrounding reservoir parameters, which causes the plume’s shape to change. Figure 3-6 below compares the group injectivity between each VWP scenario and shows that VWP 5 possesses the highest group injectivity.

![Figure 3-6: Group injectivity of the different VWP scenarios vs. Time](image-url)
We derive group injectivity using the following formula:

\[
\text{Group Injectivity} = \sum_{\text{Well} \, 1}^{\text{Well} \, 9} \frac{\text{Rate} \, (m^3/\text{day})}{\text{Pressure difference} \, (\text{bars})}
\]

The pressure difference for the equation above is the difference in pressure from the start to the end of injection for a particular well. Scenario VWP 5 shows that it requires the least amount of pressure difference (or work) in order to inject at a high rate. From here onwards, we will be using the well positions of VWP 5, unless otherwise specified.

3.9 Local Grid Refinement

We test out different local grid refinements to ensure that we minimise numerical dispersion errors. Having coarse grids instead of finer grids causes properties to be averaged over a larger volume, which leads to inaccuracies in the simulations.

Since perforation intervals are between layers 58 and 110, we apply a local grid refinement (around each well) between layers 50 and 130. There are two main reasons why we did not refine the entire Lesueur Formation. First, there would be a substantial increase in simulation time. Second, we observe a large increase in convergence issues when refining a larger number of grids. We test out several different refinement sizes. These can be seen in Figure 3-7. It should be noted that we use VWP 5 for our grid sensitivity analysis. We first compare areal grid refinements (refinements in the X and Y direction), followed by a comparison in vertical refinements (Z-direction refinements).

Figure 3-7: The different local grid refinements applied for each well. Here, X x Y x Z refers to the refinement in the X, Y and Z direction respectively.
Table 3-11 shows a summary of the results of the areal grid refinement sensitivity analysis. The results show that refining the grids in the X & Y direction increases the amount of supercritical CO₂ injected. This is because local grid refinement causes the BHP of each well to reach maximum BHP at a later time. In addition, the mobility of the supercritical CO₂ in smaller grid blocks is greater than it is in larger grid blocks. This is because, for finer grid blocks, less CO₂ is required to surpass the critical CO₂ saturation, which allows the CO₂ phase to be more mobile. As a result CO₂ easily moves from one grid block to the next. Residually trapped CO₂ increases with a higher degree of local grid refinement because of this same reason. This is because the plume is able to spread more easily outward and eventually upwards, allowing a larger volume of CO₂ to be residually trapped.

Larger grid blocks tend to overestimate the percentage of dissolved CO₂. The overestimation of dissolved CO₂ is a result of numerical dispersion which results from coarse grid blocks. This occurs mainly at the invading saturation front. Since the saturation front has a larger volume of formation brine (in which CO₂ can dissolve) for larger grid blocks, a greater amount CO₂ can dissolve (Hassanzadeh et. al 2009 and Green & Ennis-King 2012). One way to reduce this numerical dispersion in the short term is to use finer grids. Looking at Table 3-12, the same explanations apply to refining the grids vertically. However, the changes in cumulative supercritical CO₂ injected and the percentage of dissolved CO₂ are less significant. With more data about vertical heterogeneity from various sources, such as 3D seismic data and new wells, the effect of vertical grid refinement might be more significant.

Table 3-11: Summary of results for areal grid refinement (X & Y direction) sensitivity analysis after 100 years of observation (Appendix J Figures 17-1 to 17-30)

<table>
<thead>
<tr>
<th>Case type</th>
<th>CO₂ state (Mass %)</th>
<th>Cumulative CO₂ injected (Mt)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Trapped (Mt)</td>
<td>Dissolved (Mt)</td>
</tr>
<tr>
<td>Unrefined (Base Case)</td>
<td>105.4 (52.5%)</td>
<td>61.0 (30.4%)</td>
</tr>
<tr>
<td>2x2x1</td>
<td>112.2 (52.4%)</td>
<td>62.7 (29.3%)</td>
</tr>
<tr>
<td>3x3x1</td>
<td>116.8 (52.6%)</td>
<td>63.5 (28.6%)</td>
</tr>
<tr>
<td>4x4x1</td>
<td>118.1 (52.8%)</td>
<td>63.9 (28.6%)</td>
</tr>
<tr>
<td>5x5x1</td>
<td>118.5 (52.7%)</td>
<td>64.1 (28.5%)</td>
</tr>
<tr>
<td>6x6x1</td>
<td>119.1 (52.8%)</td>
<td>63.8 (28.3%)</td>
</tr>
</tbody>
</table>
Table 3-12: Summary of results for vertical grid refinement (Z direction) sensitivity analysis after 100 years of observation (Appendix J Figures 17-31 to 17-34)

<table>
<thead>
<tr>
<th>Case type</th>
<th>CO₂ state (Mass %)</th>
<th>Cumulative CO₂ injected (Mt)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Trapped (Mt)</td>
<td>Dissolved (Mt)</td>
</tr>
<tr>
<td>Unrefined (Base Case)</td>
<td>105.4 (52.5%)</td>
<td>61.0 (30.4%)</td>
</tr>
<tr>
<td>1x1x2</td>
<td>106.8 (52.5%)</td>
<td>61.2 (30.1%)</td>
</tr>
<tr>
<td>1x1x3</td>
<td>106.8 (52.4%)</td>
<td>60.9 (29.9%)</td>
</tr>
</tbody>
</table>

Figures 17-1 to 17-30 of Appendix J compare the results between each areal local grid refinement and the Base Case (Unrefined). Furthermore, Figures 17-31 to 17-34 of Appendix J compare the results between each vertical local grid refinement and the Base Case (Unrefined). It should be noted that the fluctuations seen in some of the figures (such as Figures 17-1, 17-2, 17-7 and 17-8) are due to the abrupt change in grid block size from the locally refined grids to the global grids. A complete refinement of the whole Lesueur section would smoothen out these fluctuations.

We also apply local grid refinements of 5x5x1 (an example is shown in Figure 3-8) to all the other vertical well placement scenarios and the results show that the percentage of dissolved CO₂ decreases for each scenario, while the cumulative injected CO₂ increases. A summary of the results are shown in table 3-13 below. The figures depicting these results are found in Appendix K. It should be noted that only injection rate of CO₂ and dissolution graphs are shown for these, since we will be concentrating more on VWP 5.
Table 3-13: Summary of results comparing unrefined vertical well placement scenarios and refined vertical well placement scenarios after 100 years of observation

<table>
<thead>
<tr>
<th>Case type</th>
<th>CO₂ state (Mass %)</th>
<th>Cumulative CO₂ injected (Mt)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Trapped (Mt)</td>
<td>Dissolved (Mt)</td>
</tr>
<tr>
<td>Base VWP</td>
<td>101.9 (54.1%)</td>
<td>55.8 (29.6%)</td>
</tr>
<tr>
<td>Base VWP (ref.)</td>
<td>117.3 (53.6%)</td>
<td>60.9 (27.8%)</td>
</tr>
<tr>
<td>VWP 1</td>
<td>95.8 (53.5%)</td>
<td>53.7 (30.0%)</td>
</tr>
<tr>
<td>VWP 1 (ref.)</td>
<td>112.6 (53.3%)</td>
<td>59.3 (28.1%)</td>
</tr>
<tr>
<td>VWP 2</td>
<td>94.6 (52.6%)</td>
<td>52.7 (29.3%)</td>
</tr>
<tr>
<td>VWP 2 (ref.)</td>
<td>108.4 (52.3%)</td>
<td>57.1 (27.5%)</td>
</tr>
<tr>
<td>VWP 3</td>
<td>101.3 (53.0%)</td>
<td>58.7 (30.7%)</td>
</tr>
<tr>
<td>VWP 3 (ref.)</td>
<td>116.5 (53.2%)</td>
<td>62.8 (28.7%)</td>
</tr>
<tr>
<td>VWP 4</td>
<td>105.7 (53.3%)</td>
<td>60.9 (30.7%)</td>
</tr>
<tr>
<td>VWP 4 (ref.)</td>
<td>119.3 (53.4%)</td>
<td>64.3 (28.8%)</td>
</tr>
<tr>
<td>VWP 5</td>
<td>105.4 (52.5%)</td>
<td>61.0 (30.4%)</td>
</tr>
<tr>
<td>VWP 5 (ref.)</td>
<td>118.5 (52.7%)</td>
<td>64.1 (28.5%)</td>
</tr>
</tbody>
</table>

Figure 3-8: An example of 5x5x1 local grid refinement (around well 10) that we apply
We observe from Figures 18-3, 18-6, 18-9, 18-12, 18-15 & 18-18 in Appendix K that local grid refinement takes roughly 2 to 2.5 times the simulation computational time of an unrefined model. The dissolution Figures of both Appendix J & K show that the amount of dissolved CO$_2$ is lesser for the refined model roughly before the fluctuations of mass rate occur. However, after the fluctuations of mass rate the dissolved CO$_2$ is higher than for the unrefined model. This is most probably because the plume leaves the smaller locally refined grid blocks and enters the larger global grids, which causes fluctuations in mobility and residual trapping. This further emphasises the need for proper refinement in the Lesueur Formation or even possibly beyond this formation. From this analysis, we strongly advise that the grids should be refined in the X & Y directions. From this point forward, we conduct all further analysis using a local grid refinement of 5x5x1 around the wells, as seen in Figure 3-8.

3.10 Vertical Well Optimisation

In section 3.9, we work solely with VWP 5 (Figure 3-9) since this pattern injects the highest cumulative amount of supercritical CO$_2$ in the reservoir. In this section, we test out different ways in which we can enhance the amount of residually trapped and dissolved CO$_2$ in the formation. We test out two different parameters -

- effects of changing perforation depth
- effects of changing perforation interval

![VWP 5](image)

*Figure 3-9: VWP 5 along with its respective well positions and numbers*
3.10.1 Perforation Depth

For our first set of tests, we keep the perforation interval at exactly 500 m for each well. We place the top of the perforation interval at three different depths. These depths are based on layer numbers rather than actual subsurface depths. The layers are (refer to Figure 3-10):

- Layer 51 (Top Upper Wonnerup)
- Layer 56 (Mid Upper Wonnerup)
- Layer 66 (Low Upper Wonnerup)

The results in Table 3-14 show that when the perforation interval starts at layer 56, we inject the most supercritical CO\textsubscript{2}. Table 3-15 show that layers 51-66 (Wonnerup 1 which is roughly the same interval of our perforation starting at layer 51) has the highest mean permeability with a few low permeability layers. However, it does not inject as much CO\textsubscript{2}. This is because the perforations starting at layer 51 have several low permeability layers directly above. As a result, the plume immediately rises to the top and this accumulates just below the low permeability barrier. As the CO\textsubscript{2} column under the low permeability barrier accumulates it spreads out around the top of the perforation. This causes the BHP at the top of the perforation to increase rapidly, forcing the well to inject at a lower rate. Figure 3-11 shows the group injectivity of the wells and shows that perforations starting at layer 51 are the best at the beginning due to the higher surround average permeability. However, it also shows the point at which injectivity decreases because the CO\textsubscript{2} plume accumulates around the top perforation.

Perforations starting at layer 66 have a low mean permeability around the injection interval, which explains the low cumulative injection of supercritical CO\textsubscript{2}. Furthermore, there is a low permeability layer above layer 66, which causes the same problem as the perforations at layer 51. This causes the BHP to rise rapidly to the maximum allowable pressure, thus lowering the injection rate. On the other hand, perforations starting at layer 56 have an average permeability in between those starting at layer 51 and those starting at layer 66. However, these perforation intervals are located such that the top part of the perforation interval is exposed to several hundred meters of high permeability sands. This allows the plume to migrate away from the top of the perforation interval easily, allowing BHP to rise slowly.

Perforations starting at layer 51 have the highest percentage of residually trapped CO\textsubscript{2} because of the higher surrounding average permeability. Perforations starting at layer 66 have the lowest surrounding average permeability; hence it traps the least amount of residual CO\textsubscript{2}.

The percentage of dissolved CO\textsubscript{2} is higher for perforations starting at layer 66, compared to perforations starting at layer 51. This is because there is a low permeability layer above layer 51. As the plume spreads out laterally under the low permeability layer, the surface area increases (see Figure 3-13). However, because there are low permeability areas above the CO\textsubscript{2} plume, the effective surface area in contact with fresh brine is reduced. The same phenomenon occurs for perforations starting at layer 66. However, because there are several low permeability layers, we achieve “stacked-disc” CO\textsubscript{2} plumes (see Figure 3-12). This increases the contact surface area with the surrounding brine, increasing the amount of dissolved CO\textsubscript{2}. Perforations starting at layer 56 have the highest amount of dissolved CO\textsubscript{2} because the top part of the perforation interval is exposed to a thick and high permeability
layer. As a result, the plume can migrate upwards, increasing the contact area between CO$_2$ and brine, which increases the amount of dissolved CO$_2$ (Taheri et. al. 2012 & Sifuentes 2009). In addition, the bottom part of the perforation interval (after layer 56) achieves a “stacked-disc” plume. As a result, perforation starting at layer 56 combines the best traits of the other two perforation starting depths in terms of dissolution trapping.

Appendix L, Figures 19-2 to 19-7 show the amount of residually trapped, dissolved and mobile CO$_2$ in the Yalgorup and Wonnerup Formation after 100 years of observation. These graphs show that when we inject CO$_2$ at a deeper point in the formation, less CO$_2$ reaches the Yalgorup Formation. Although there is a significantly higher percentage of mobile CO$_2$ for perforation lengths starting at layer 51 and 66, most of it is structurally trapped. However, the E-300 simulator does not differentiate between structurally trapped and mobile CO$_2$. This is seen from the amount of mobile CO$_2$ in the Yalgorup formation after 100 years of observation (see Figure 19-6).

Figure 3-10: Diagram showing the different layers for the start of perforation interval
Figure 3-11: Group injectivity vs. Time for well perforations starting at layer 51 (blue), layer 56 (red) and layer 66 (green). The black circle indicates the period in which group injectivity of wells with perforation starting at layer 56 overtakes those with perforations starting at layer 51. This is because of the accumulation of the CO₂ plume around the top of the perforation interval caused by several low permeability layers above layer 51.

Table 3-14: Summary of results for different starting perforation depths of vertical wells, after 100 years of observation (Appendix L, Figures 47-1 to 47-7)

<table>
<thead>
<tr>
<th>Perforation starting at</th>
<th>CO₂ state (Mass %)</th>
<th>Cumulative CO₂ injected (Mt)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Trapped (Mt)</td>
<td>Dissolved (Mt)</td>
</tr>
<tr>
<td>Layer 51</td>
<td>117.1 (57.3%)</td>
<td>48.4 (23.7%)</td>
</tr>
<tr>
<td>Layer 56</td>
<td>127.1 (56.5%)</td>
<td>66.6 (29.6%)</td>
</tr>
<tr>
<td>Layer 66</td>
<td>87.7 (49.5%)</td>
<td>49.1 (27.7%)</td>
</tr>
</tbody>
</table>
Table 3-15: Mean permeability of perforation intervals

<table>
<thead>
<tr>
<th>Perforation starting at</th>
<th>Rough interval of perforation (layers)</th>
<th>Mean permeability (X or Y)</th>
<th>Mean permeability (Z)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Layer 51</td>
<td>51 - 66</td>
<td>43.9 mD</td>
<td>4.4 mD</td>
</tr>
<tr>
<td>Layer 56</td>
<td>56 - 83</td>
<td>10.0 mD</td>
<td>1.0 mD</td>
</tr>
<tr>
<td>Layer 66</td>
<td>66 - 95</td>
<td>6.4 mD</td>
<td>0.6 mD</td>
</tr>
</tbody>
</table>

Figure 3-12: Perforations starting at layer 66 that result in "stacked-disc" plumes
3.10.2 Perforation Interval

We now keep all perforations starting at layer 56, because the residually trapped CO₂ and dissolved CO₂ are higher, and test out the effects of perforation intervals. We then test out the effects of the following different perforation intervals:

- 350 m
- 500 m
- 650 m

Table 3-16 shows that increasing the perforation interval increases the amount of supercritical CO₂ injected. This is expected since increasing the perforation interval would result in a larger injection area, which reduces the BHP. Furthermore, this is supported by the group injectivity graph in Figure 3-14. This shows that we have the highest group injectivity with a perforation interval of 650 m, but the lowest group injectivity with a perforation interval of 350 m.

We notice that the percentage of residually trapped CO₂ tends to increase with a smaller perforation interval. This is because the CO₂ plume tends to take on a more uniform shape, allowing for more residual trapping to take place as the CO₂ rises (Kumar & Bryant 2008). On the other hand, percentage of dissolved CO₂ increases slightly with increasing perforation interval because we achieve a larger contact area with brine (Sifuentes et. al 2009).

We did not optimise perforation interval to try to increase the uniformity of the injection profile which was performed by Kumar & Bryant 2008. This would eventually achieve a higher degree of residual and dissolution trapping. The study
conducted by Kumar & Bryant 2008 involved a single injection well, a constant injection rate and in a homogeneous reservoir. It was previously agreed during the October 4 Technical Presentation in Perth that we would use a group injection method. Changing the perforation interval of any of the wells would result in a change in injection rate in that well. In addition, if we did use a constant injection rate for each well, we would need to factor in the interference between wells, which would take a considerable amount of time.

We conclude from this study that perforations should start at layer 56 for optimal trapping, dissolution and injection benefits. In addition, it is best to choose the longest perforation as possible to inject the highest amount of supercritical CO$_2$.

Table 3-16: Summary of results for vertical well perforation length analysis after 100 years of observation (figures 19-8 to 19-14, Appendix L)

<table>
<thead>
<tr>
<th>Perforation interval</th>
<th>CO$_2$ state (Mass %)</th>
<th>Cumulative CO$_2$ injected (Mt)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Trapped (Mt)</td>
<td>Dissolved (Mt)</td>
</tr>
<tr>
<td>350 m</td>
<td>124.9 (57.1%)</td>
<td>64.8 (29.6%)</td>
</tr>
<tr>
<td>500 m</td>
<td>127.1 (56.5%)</td>
<td>66.6 (29.6%)</td>
</tr>
<tr>
<td>650 m</td>
<td>129.7 (56.6%)</td>
<td>68.0 (29.7%)</td>
</tr>
</tbody>
</table>

Figure 3-14: Group injectivity vs. Time for perforation intervals 350 m (blue), 500 m (red) and 650 m (green)
3.11 Horizontal Well Optimisation

In this section we test out different ways in which we can enhance residual trapping and dissolution of CO₂ in the formation using horizontal wells. Figure 3-15 shows the position and orientation of the horizontal wells. These positions are slightly different from the positions in VPW 5. The wells are further from each other to prevent interference. As in section 3.10, we test out two different parameters -

- effects of changing injection depth
- effects of changing perforation interval

![Figure 3-15: Position and orientation of the horizontal wells](image)

3.11.1 Perforation Depth

For our first set of tests, we keep the perforation interval at roughly 2,000 m for each well. We place all the horizontal sections of the wells along a single layer. The layers tested are (refer to Figure 3-10) -

- Layer 51 (Top Upper Wonnerup)
- Layer 56 (Mid Upper Wonnerup)
- Layer 66 (Low Upper Wonnerup)
Table 3-17: Summary of results for horizontal well injection at different layers after 100 years of observation (Figures 20-1 to 20-7, Appendix M)

<table>
<thead>
<tr>
<th>Injection depth</th>
<th>CO₂ state (Mass %)</th>
<th>Cumulative CO₂ injected (Mt)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Trapped (Mt)</td>
<td>Dissolved (Mt)</td>
</tr>
<tr>
<td>Layer 51</td>
<td>91.6 (50.7%)</td>
<td>31.4 (17.4%)</td>
</tr>
<tr>
<td>Layer 56</td>
<td>114.6 (58.1%)</td>
<td>52.1 (26.4%)</td>
</tr>
<tr>
<td>Layer 66</td>
<td>75.2 (47.2%)</td>
<td>37.4 (23.5%)</td>
</tr>
</tbody>
</table>

Table 3-17 shows that placing all the horizontal sections in layer 56 leads to the highest amount of cumulative supercritical CO₂ being injected. Layers above layer 56 are thick and less heterogeneous compared to the rest of the reservoir. In contrast, layer 51 is located right below a low permeability layer, while layer 66 is sandwiched in between several low permeability layers. As a result, maximum BHP would be reached sooner when injecting in layer 51 and 66 compared to layer 56. This is supported by the group injectivity profiles for the different injection depths in Figure 3-16. Residual trapping is highest in layer 56 for two main reasons. First, Table 3-18 shows that average permeability in layer 56 is the highest. We recall in section 3.5 that a higher permeability results in a higher amount of residual trapping. Second, at layer 56, the plume is able to rise up into the less heterogeneous thick reservoir section, which promotes residual trapping.

The percentage of dissolved CO₂ is highest in layer 56 because it is more permeable (it has less heterogeneity and fewer low permeable layers). First, this gives the CO₂ a larger surface contact area with brine. Second, the same reason seen in section 3.10.1 (concerning the low permeability layer above layer 51 and CO₂ stacked disc plume forming at layer 66) applies for the percentage of dissolved CO₂ in layers 51 and 66.

Table 3-18: Mean permeability of layers

<table>
<thead>
<tr>
<th>Layer</th>
<th>Mean permeability (X or Y)</th>
<th>Mean permeability (Z)</th>
</tr>
</thead>
<tbody>
<tr>
<td>51</td>
<td>13.3 mD</td>
<td>1.3 mD</td>
</tr>
<tr>
<td>56</td>
<td>40.4 mD</td>
<td>4.0 mD</td>
</tr>
<tr>
<td>66</td>
<td>2.3 mD</td>
<td>0.2 mD</td>
</tr>
</tbody>
</table>
3.11.2 Perforation Interval

We now keep all the horizontal sections in layer 56 because this layer shows the best residual and dissolution trapping. We test out the following perforation intervals (the perforation intervals are roughly around these lengths and might not be exact) -

- 1,000 m
- 2,000 m
- 3,000 m

We extend the horizontal perforation intervals beyond 500 m for several reasons stated below:

- We need to inject between 200 and 260 Mt of CO₂ for the entire 40 years of injection (Department of Mines & Petroleum 2012 and Schlumberger 2013). Using horizontal perforation intervals of 2,000 m allows us to inject only 197 Mt of CO₂. If we inject CO₂ using horizontal perforation intervals less than 500 m (with only 9 injection wells), we would not be able to inject the required amount.
- To gain the full benefits of horizontal wells we need horizontal perforation intervals of 2,000 m or more. The reasons are stated below -
  a. Kumar & Bryant (2008) found that increasing the horizontal perforation interval reduces the lateral velocity (and spreading) of the plume, making gravitational forces more influential. This reduces the lateral contact area with brine. Their study showed that a longer horizontal perforation interval slows down the speed at which the plume migrates upwards. Furthermore, they tested a vertical injection well with a set perforation interval and compared it to a horizontal well with a much
larger horizontal perforation length (double and even triple the perforation length of the vertical well). The speed at which the CO₂ plume migrates upwards did not significantly decrease. However, they reported that a horizontal perforation interval above 2,000 m would slow down the vertical migration of the CO₂ plume. Therefore, in order to try and slow down the vertical migration of the plume, we chose a relatively longer perforation interval.

b. Our study consists of 9 horizontal injection wells in a highly heterogeneous reservoir. In addition, we use a group injection function. The group injection function is a set injection rate that is distributed among all the injection wells in the reservoir. Each well's injection rate changes according to their respective pressure build-up. We agreed to use a group injection function during a teleconference in September and during the Technical workshop on the 4th of October. Changing the perforation interval would change the injection rates. Finding the optimal horizontal perforation interval, taking into account interference between wells, would take a considerable amount of time.

Table 3-19 shows that that the longer the perforation interval, the higher the amount of supercritical CO₂ injected. We expect this since increasing the perforation interval would result in a larger injection area, which reduces the BHP. Figure 3-17 supports this and shows that we have the highest group injectivity with a perforation interval of roughly 3,000 m, but the lowest group injectivity with a perforation interval of roughly 1,000 m.

Table 3-19: Summary of results for different horizontal perforation interval after 100 years of observation (Figures 20-8 to 20-14, Appendix M)

<table>
<thead>
<tr>
<th>Perforation interval (roughly)</th>
<th>CO₂ state (Mass %)</th>
<th>Cumulative CO₂ injected (Mt)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Trapped (Mt)</td>
<td>Dissolved (Mt)</td>
</tr>
<tr>
<td>1,000 m</td>
<td>110.6 (58.6%)</td>
<td>50.9 (27.0%)</td>
</tr>
<tr>
<td>2,000 m</td>
<td>114.6 (58.1%)</td>
<td>52.1 (26.4%)</td>
</tr>
<tr>
<td>3,000 m</td>
<td>120.1 (57.6%)</td>
<td>54.4 (26.1%)</td>
</tr>
</tbody>
</table>
The percentage of residually trapped CO$_2$ decreases with an increasing perforation interval. This is because having a greater horizontal perforation interval reduces the horizontal velocity of the plume during injection (viscous forces are reduced). As a result, gravity forces are more influential, which causes the plume to have a smaller contact area with brine in the horizontal direction (Kumar et al. 2008).

Table 3-19 shows that increasing the perforation interval decreases the percentage of CO$_2$ dissolved. However, the contrary should be happening. The dissolved CO$_2$ should increase because of the “increased surface area to volume ratio” of the plume (or distance between supercritical CO$_2$ interface and brine). The reason why the percentage of dissolved CO$_2$ decreases for the longer perforation intervals is that more of the CO$_2$ plume is concentrated in the refined grids (see Figure 3-18). This is because horizontal velocity is lower with a longer horizontal perforation section (as seen in the previous paragraph). Because we have a longer perforation interval, there will be a larger number of refined grids. In addition, as mentioned in section 3.9, coarser grids tend to over-estimate the amount of dissolved CO$_2$ in a reservoir (Green & Ennis-King 2012). In this case, grid refinement tends to be the more sensitive parameter, effectively reducing the amount of CO$_2$ dissolved even though we have an “increased surface area to volume ratio”.

Figure 3-17: Group injectivity vs. Time for horizontal perforation intervals 1,000 m (blue), 2,000 m (red) and 3,000 m (green)
We conclude from this study that horizontal perforations in layer 56 are best for trapping, dissolution and injection benefits. We did not test scenarios which have horizontal perforation sections in different layers. Such scenarios could yield more beneficial trapping results (both residual and dissolution). However, given time constraints, this was not feasible. In addition, neglecting the effects of grid refinement, it is best to choose the longest perforation as is economically possible. This enables us to inject the highest amount of supercritical CO$_2$ and thereby, enhance both residual and dissolution trapping by maximising contact area with brine (Kumar et. al. 2008).

3.12 Vertical Injection Wells & Production Wells

Next we test out different ways to enhance residual trapping and dissolution of CO$_2$ in the formation using vertical injection wells and water production wells. Figure 3-19 shows the positions of both injection and production wells. The positions of the injection wells are exactly the same as in VWP 5. We place the production well positions in between the injection wells. The water producers are set to produce at a voidage rate equal to the amount of CO$_2$ injected in the same segment that they are placed. This is an attempt to relief reservoir pressure build-up in the reservoir. The
borders in between the segments are actually closed faults in the dynamic model. An example of this principle is explained below.

WAT_4 is located in segment 5 with CO2_5 & CO2_11. Hence, WAT_4 has a target to produce the same volume of water as the volume of CO2 injected by both CO2_5 and CO2_11.

Similar to section 3.10, we test out two different parameters -

- effects of changing injection depth
- effects of changing perforation interval

![Figure 3-19: Vertical injection well and production well positions along with segment boundaries](image)

3.12.1 Perforation Depth

We first vary perforation depth, but keep the perforation interval fixed at 500 m for both injection and production wells. As in section 3.10, we test out perforation depth of both injection and production wells starting at a specific layer number, which are -

- Layer 51
- Layer 56
- Layer 66

From the results in Tables 3-20 and 3-21, we observe that the full amount of cumulative supercritical CO2 can be injected (refer to Figure 21-1). The breakthrough time for all three different perforation depths is 8 - 9 years (refer to Figure 21-1). In addition, because the permeability of layers 51 - 66 and layers 56 - 83 is high (refer Table 3-15), we produce a higher amount of cumulative CO2 and water compared to the case in which perforations start at layer 66 (Figures 21-1, 21-3, 21-10 & 21-11).
Since we do not produce as much water for perforations starting at layer 66, the final average reservoir pressure is the highest for this case compared to the other two cases (refer to Table 3-22).

Table 3-20: Summary of the results for vertical injection and production perforation depth analysis after 100 years of observation (Figures 21-1, 21-2, 21-4 to 21-9, Appendix N)

<table>
<thead>
<tr>
<th>Perforation starting point</th>
<th>CO₂ state (Mass %)</th>
<th>*NET cumulative CO₂ injected (Mt)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Trapped (Mt)</td>
<td>Dissolved (Mt)</td>
</tr>
<tr>
<td>Layer 51</td>
<td>114.2 (55.4%)</td>
<td>47.0 (22.8%)</td>
</tr>
<tr>
<td>Layer 56</td>
<td>117.4 (57.4%)</td>
<td>63.4 (31.0%)</td>
</tr>
<tr>
<td>Layer 66</td>
<td>109.6 (49.1%)</td>
<td>55.8 (25.0%)</td>
</tr>
</tbody>
</table>

*NOTE: Net cumulative CO₂ injected = Cumulative CO₂ injected - Cumulative CO₂ produced

Table 3-21: Cumulative CO₂ produced for perforation depth analysis for vertical injection and production wells after 100 years of observation (Figure 21-3)

<table>
<thead>
<tr>
<th>Perforation starting point</th>
<th>Cumulative CO₂ Produced (Mt)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Layer 51</td>
<td>23.3</td>
</tr>
<tr>
<td>Layer 56</td>
<td>24.8</td>
</tr>
<tr>
<td>Layer 66</td>
<td>6.0</td>
</tr>
</tbody>
</table>

Table 3-22: Final average reservoir pressure for different starting perforation depths for vertical injection and production wells after 100 years of observation

<table>
<thead>
<tr>
<th>Perforation starting point</th>
<th>Final average reservoir pressure (bar)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Layer 51</td>
<td>207.4</td>
</tr>
<tr>
<td>Layer 56</td>
<td>206.7</td>
</tr>
<tr>
<td>Layer 66</td>
<td>221.0</td>
</tr>
</tbody>
</table>

For this injection design, we observe that the percentage of residually trapped CO₂ is highest when perforation starts at layer 56 compared to layer 51. This is because perforations starting at layer 51 have a low permeability layer directly above layer 51, which restricts the plume from rising upwards. As a result, the CO₂ plume is dragged just below the low permeability layer towards the producer due to the pressure difference created. This is supported by Figure 21-1 & 21-3 of Appendix N, where breakthrough for perforations starting at layer 51 occurs earlier than
breakthrough for perforations starting at layer 56. On the other hand, the CO$_2$ plume for perforations starting at layer 56 rises upwards into the upper thick (less heterogeneous) reservoir with few low permeability layers. This increases the amount of residually trapped CO$_2$ before breakthrough actually happens. This also increases the volume of the plume, allowing more CO$_2$ to be residually trapped. The same reasoning used in section 3.10 can be used to explain the percentage of dissolved CO$_2$ and mobile CO$_2$ for all three layers.

### 3.12.2 Perforation Interval

We now keep all perforations starting at layer 66. This is because we inject the most net cumulative CO$_2$ in this layer and most of the CO$_2$ does not reach the Yalgorup Formation after 100 years of observation. We then test out the effects of different perforation intervals:

- 350 m
- 500 m
- 650 m

Table 3-23 & 3-24 show that increasing the perforation interval increases the amount of cumulative CO$_2$ injected. This is expected since increasing the perforation interval would result in a larger injection area, which reduces the BHP. In addition, Figures 21-12 to 21-14 show that the net cumulative CO$_2$ injected is higher for perforation intervals 500 m & 650 m. This is because perforation interval 350 m has a smaller injection area, which causes the CO$_2$ plume to spread out further laterally. As a result, a larger amount of the CO$_2$ plume reaches the production well earlier. Figures 21-21 & 21-22 also show that the longer the perforation interval, the more water is produced.

**Table 3-23: Summary of results for perforation length analysis for vertical injection and production wells after 100 years of observation (Figures 21-12, 21-13 & 21-15 to 21-20, Appendix N)**

<table>
<thead>
<tr>
<th>Perforation interval</th>
<th>CO$_2$ state (Mass %)</th>
<th>*NET cumulative CO$_2$ injected (Mt)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Trapped (Mt)</td>
<td>Dissolved (Mt)</td>
</tr>
<tr>
<td>350 m</td>
<td>105.0 (48.7%)</td>
<td>54.1 (25.1%)</td>
</tr>
<tr>
<td>500 m</td>
<td>109.6 (49.1%)</td>
<td>55.8 (25.0%)</td>
</tr>
<tr>
<td>650 m</td>
<td>109.4 (49.0%)</td>
<td>58.1 (26.0%)</td>
</tr>
</tbody>
</table>

*NOTE: Net cumulative CO$_2$ injected = Cumulative CO$_2$ injected - Cumulative CO$_2$ produced*
Table 3-24: Cumulative CO$_2$ produced for perforation interval analysis for vertical injection and production wells after 100 years of observation (Figure 49-14)

<table>
<thead>
<tr>
<th>Perforation interval</th>
<th>Cumulative CO$_2$ Produced (Mt)</th>
</tr>
</thead>
<tbody>
<tr>
<td>350 m</td>
<td>7.6</td>
</tr>
<tr>
<td>500 m</td>
<td>6.0</td>
</tr>
<tr>
<td>650 m</td>
<td>6.0</td>
</tr>
</tbody>
</table>

The percentage of residually trapped CO$_2$ is the highest with a perforation interval of 500 m. This is because those layers have the highest mean average permeability (see Table 3-25). The percentage of residually trapped CO$_2$ is slightly higher for perforation interval 650 m compared to 350 m because we inject CO$_2$ deeper (especially at the bottom of the perforation). This leads to slightly higher residual trapping due to the increased surrounding hydrostatic pressure at the bottom on the perforation (Sifuentes et. al. 2008). Increasing the perforation interval increases the percentage of dissolved CO$_2$. This is because we have more contact area with fresh brine, allowing more CO$_2$ to dissolve (Sifuentes et. al 2009).

Table 3-25: Mean permeabilities for different perforation intervals starting at layer 66

<table>
<thead>
<tr>
<th>Perforation interval</th>
<th>Rough interval of perforation (layers)</th>
<th>Mean permeability (X or Y)</th>
<th>Mean permeability (Z)</th>
</tr>
</thead>
<tbody>
<tr>
<td>350 m</td>
<td>66 - 88</td>
<td>5.7 mD</td>
<td>0.6 mD</td>
</tr>
<tr>
<td>500 m</td>
<td>66 - 95</td>
<td>6.4 mD</td>
<td>0.6 mD</td>
</tr>
<tr>
<td>650 m</td>
<td>66 - 114</td>
<td>5.2 mD</td>
<td>0.5 mD</td>
</tr>
</tbody>
</table>

We conclude from this study that vertical injection and water production is optimal when perforation starts near layer 66. This leads to the highest amount of net cumulative injected supercritical CO$_2$. In addition, after 100 years of observation, we note that the least amount of mobile CO$_2$ is in the Yalgorup Formation, which is safest. Furthermore, it is best to choose the longest perforation as economically possible for the best overall trapping benefit.

### 3.13 Water Alternate Gas (WAG)

We also test out different ways to enhance residual trapping and dissolution of CO$_2$ using Water Alternate Gas (WAG) wells and production wells. Figure 3-20 shows the positions of both injection and production wells. These are the same positions as the vertical injection and production well scenario of section 3.12, which means the WAG injection wells have the same position as VWP 5. The water producers are set to produce at a voidage rate equal to the amount of CO$_2$ injected in the same segment that they are placed. This is an attempt to relieve reservoir pressure build-up in the
reservoir. The borders in between the segments are actually closed faults in the dynamic model. An example of this principle is explained below:

WAT_5 is located in segment 6 with WAG_12 & WAG_16. Therefore, WAT_5 has a target to produce the same volume of water as the volume of CO₂ & water injected by both WAG_12 and WAG_16.

We analyse two different parameters:

- effects of changing perforation interval
- effects of changing WAG injection cycle (or WAG ratio of CO₂ to water)

![Legend:]
- WAG injector (same locations as VWP 5)
- Water producer

![Figure 3-20: WAG injection and production wells along with segment boundaries]

### 3.13.1 Perforation Interval

We first vary the perforation interval, but keep the perforation starting depth at layer 56 for both injection and production wells. As in section 3.10 & 3.12, we analyse the following perforation interval of both injection and production wells -

- 350 m
- 500 m
- 650 m

Tables 3-26 & 3-27 show that increasing the perforation interval increases the amount of cumulative CO₂ injected. This is expected since increasing the perforation interval would result in a larger injection area, which reduces the BHP. In addition, Figures 22-1 to 22-3 show that the net cumulative CO₂ injected is higher for longer perforation intervals. For smaller perforation intervals, we have a smaller injection area, which causes the CO₂ plume to spread out further laterally. As a result, a larger
portion of the CO₂ plume would reach the production well earlier. Figures 22-10 to 22-13 also show that the longer the perforation interval, the more cumulative water is injected and produced.

The percentage of residually trapped CO₂ decreases, while the percentage of dissolved CO₂ increases with increasing perforation interval. The reasons why this happens is similar to the reasons explained in section 3.10.

Table 3-26: Summary of results for the different perforation intervals of WAG injection and production wells after 100 years of observation (Figures 22-1, 22-2, 22-4 to 22-9, Appendix O)

<table>
<thead>
<tr>
<th>Perforation interval</th>
<th>CO₂ state (Mass %)</th>
<th>*NET cumulative CO₂ injected (Mt)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Trapped (Mt)</td>
<td>Dissolved (Mt)</td>
</tr>
<tr>
<td>350 m</td>
<td>113.5 (57.3%)</td>
<td>68.3 (34.5%)</td>
</tr>
<tr>
<td>500 m</td>
<td>115.5 (57.0%)</td>
<td>70.9 (35.0%)</td>
</tr>
<tr>
<td>650 m</td>
<td>118.0 (57.0%)</td>
<td>73.7 (35.6%)</td>
</tr>
</tbody>
</table>

*NOTE: Net cumulative CO₂ injected = Cumulative CO₂ injected - Cumulative CO₂ produced

Table 3-27: Cumulative amount of CO₂ produced for the different perforation intervals for WAG injection and production wells after 100 years of observation (Figure 22-3, Appendix O)

<table>
<thead>
<tr>
<th>Perforation interval</th>
<th>Cumulative CO₂ Produced (Mt)</th>
</tr>
</thead>
<tbody>
<tr>
<td>350 m</td>
<td>18.9</td>
</tr>
<tr>
<td>500 m</td>
<td>17.0</td>
</tr>
<tr>
<td>650 m</td>
<td>14.7</td>
</tr>
</tbody>
</table>

3.13.2 WAG Cycle Ratio

We now keep all perforations intervals set at 500 m. We then test out the effects of different WAG cycle ratios, which include -

- 1 year of water injection : 1 year of CO₂ injection
- 1 year of water injection : 2 years of CO₂ injection
- 2 years of water injection : 1 year of CO₂ injection

Tables 3-28 & 3-29 show that increasing the ratio of CO₂. Water increases the amount of cumulative injected CO₂. It also increases the amount of cumulative CO₂ produced.

The percentage of residually trapped CO₂ increases as we inject a larger ratio of CO₂ to water. This is because we effectively inject CO₂ plumes that have large volumes, but smaller surface area, which increases trapping. This also explains how the percentage of dissolved CO₂ decreases when a larger ratio of CO₂ is injected.
compared to water. This supports the theory that residual trapping and dissolution trapping are competing mechanisms Ngheim et al. (2009).

We conclude from this study that the longest perforation interval economically possible should be used. In addition, a WAG cycle ratio of 1:1 should be used. These injection settings would yield the greatest overall benefit for the overall trapping benefit of CO₂ (both residual and dissolution) and the cumulative amount of supercritical CO₂ injected.

Table 3-28: Summary of results for different WAG cycle ratios for WAG injection and production wells after 100 years of observation (Figures 22-14, 22-15, 22-17 to 22-22, Appendix O)

<table>
<thead>
<tr>
<th>WAG cycle ratio (CO₂ : Water)</th>
<th>CO₂ state (Mass %)</th>
<th>*NET cumulative CO₂ injected (Mt)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Trapped (Mt)</td>
<td>Dissolved (Mt)</td>
</tr>
<tr>
<td>1:2</td>
<td>76.5 (54.9%)</td>
<td>56.2 (40.3%)</td>
</tr>
<tr>
<td>1:1</td>
<td>115.5 (57.0%)</td>
<td>70.9 (35.0%)</td>
</tr>
<tr>
<td>2:1</td>
<td>119.4 (57.4%)</td>
<td>69.5 (33.4%)</td>
</tr>
</tbody>
</table>

*NOTE: Net cumulative CO₂ injected = Cumulative CO₂ injected - Cumulative CO₂ produced

Table 3-29: Cumulative amount of CO₂ produced for the different WAG cycle ratios for WAG injection and production wells after 100 years of observation (Figure 22-16, Appendix O)

<table>
<thead>
<tr>
<th>WAG cycle ratio (CO₂ : Water)</th>
<th>Cumulative CO₂ Produced (Mt)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1:2</td>
<td>7.0</td>
</tr>
<tr>
<td>1:1</td>
<td>17.0</td>
</tr>
<tr>
<td>2:1</td>
<td>16.4</td>
</tr>
</tbody>
</table>

3.14 Simultaneous Water Alternate Gas (SWAG)

In order to analyse the effect of SWAG, we apply an engineering design suggested by Anchilya & Ehlig-Economides (2009). This design includes a horizontal CO₂ injection well and a horizontal brine injection well located directly above it. In addition, two horizontal brine producers are located on both sides of the CO₂ injector. The producers relieve reservoir pressure build-up and help drag the CO₂ plume laterally. The horizontal brine injector, located above the CO₂ injector, aims to increase both dissolution and residual trapping. It does this based on the principles of counter-current water flow and forced imbibition. Figure 3-21 shows a simple schematic of the engineering design. Figure 3-22 shows the position and orientation of the wells. We place the wells in the less heterogeneous zone (see Figure 3-10), surrounded by
high permeability. The positions are not the same as scenario VWP 5 or the horizontal well positions.

We set the water producers to produce at a voidage rate equal to the amount of CO$_2$ injected in the same segment. An example of this is explained below.

WAT_5 & WAT_6 are located in segment 6 with CO2_3 & WATINJ_3. Hence, WAT_5 & WAT_6 have a target to produce the same volume of water as the volume of CO$_2$ & water injected by both CO2_3 and WATINJ_3.

We test out three different parameters:

- CO$_2$ injector perforation interval.
- Distance between brine injector and CO$_2$ injector.
- Distance between CO$_2$ injector and brine producers.

![Figure 3-21: SWAG injection design proposed by Anchilya & Ehlig-Economides (2009)](image)

![Figure 3-22: Position and orientation of SWG designs in the reservoir. The water injectors are shown beside the CO$_2$ injectors for visual purposes.](image)
Our base case for SWAG includes the following parameters -

- CO₂ horizontal injector is at layer 55 or 56.
- Distance between CO₂ and brine injector = 300 m.
- Distance between injector and producers = 2,100 m.
- CO₂ injector perforation interval = 1,200 m.
- Brine injector perforation interval = 2,000 m.
- Maximum water injection rate of 171,176 m³/day. However, injection pressure is limited to 90% of the fracture pressure at the depth of perforation.

### 3.14.1 CO₂ Injector Perforation Interval

We first vary the CO₂ injector perforation interval, while keeping all the other parameters constant. The following CO₂ injector perforation intervals are tested -

- 600 m
- 1,200 m
- 1,800 m

Tables 3-30 & 3-31 show that increasing the perforation interval increases the amount of cumulative CO₂ injected. This is expected since increasing the perforation interval would result in a larger injection area, which lowers the BHP. In addition, Figures 23-1 to 23-3 show that the net cumulative CO₂ injected is higher for perforation longer perforation intervals. This is because for smaller perforation intervals, we have a smaller injection area, which causes the CO₂ plume to spread out further laterally. As a result, more of the CO₂ plume would reach the production well earlier. Figures 23-12 to 23-13 also show that the longer the perforation interval, the more cumulative water is produced. Breakthrough for all the cases occurs around the 7 year mark. The percentage of residually trapped CO₂ fluctuates as perforation interval changes and, as we have previously seen, the percentage of dissolved CO₂ increases with increasing perforation interval.

**Table 3-30: Summary of results for CO₂ injector perforation interval analysis after 100 years of observation (Figures 23-1, 23-2, 23-4 to 23-9, Appendix P)**

<table>
<thead>
<tr>
<th>Perforation interval</th>
<th>CO₂ state (Mass %)</th>
<th>*NET cumulative CO₂ injected (Mt)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Trapped (Mt)</td>
<td>Dissolved (Mt)</td>
</tr>
<tr>
<td>600 m</td>
<td>89.4 (52.8%)</td>
<td>31.5 (18.6%)</td>
</tr>
<tr>
<td>1,200 m</td>
<td>92.7 (52.0%)</td>
<td>33.0 (18.5%)</td>
</tr>
<tr>
<td>1,800 m</td>
<td>96.7 (52.8%)</td>
<td>35.5 (19.4%)</td>
</tr>
</tbody>
</table>

*NOTE: Net cumulative CO₂ injected = Cumulative CO₂ injected - Cumulative CO₂ produced*
Table 3-31: Cumulative amount of CO$_2$ produced for different perforation interval lengths after 100 years of observation (Figure 23-3, Appendix P)

<table>
<thead>
<tr>
<th>Perforation interval</th>
<th>Cumulative CO$_2$ Produced (Mt)</th>
</tr>
</thead>
<tbody>
<tr>
<td>600 m</td>
<td>51.9</td>
</tr>
<tr>
<td>1,200 m</td>
<td>51.3</td>
</tr>
<tr>
<td>1,800 m</td>
<td>46.3</td>
</tr>
</tbody>
</table>

3.14.2 Distance between CO$_2$ & Brine Injectors

We then vary the distance between the CO$_2$ injector and the brine injector, while keeping all the other parameters constant. The following distances are tested -

- 150 m
- 300 m

Figure 50-14 shows that we inject the full amount of cumulative supercritical CO$_2$ into the formation. However, Tables 3-32 & 3-33 show that increasing the distance between the two injectors leads to an increase in the net cumulative amount of CO$_2$ injected. Placing the injectors closer to each other causes the CO$_2$ plume to spread more laterally outwards, which results in CO$_2$ reaching the producers quicker. Because of this spreading, the CO$_2$ plume occupies a larger surface area. This causes the percentage of dissolved CO$_2$ to increase when placing the injectors closer to each other. Figures 23-23 to 23-26 also show that the further the distance between the injectors, the more cumulative water is injected and produced.

The percentage of residually trapped CO$_2$ increases slightly when the distance between the two injectors increase. This occurs because the CO$_2$ plume can rise up further, allowing more CO$_2$ to be trapped along the way before colliding with the downward brine stream from the brine injector above.

Table 3-32: Summary of analysis for distance between CO$_2$ injector and brine injector after 100 years of observation (Figures 23-14, 23-15, 23-17 to 23-22, Appendix P)

<table>
<thead>
<tr>
<th>Distance between injectors</th>
<th>CO$_2$ state (Mass %)</th>
<th>*NET cumulative CO$_2$ injected (Mt)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Trapped (Mt)</td>
<td>Dissolved (Mt)</td>
</tr>
<tr>
<td>150 m</td>
<td>50.4 (51.9%)</td>
<td>22.5 (23.2%)</td>
</tr>
<tr>
<td>300 m</td>
<td>92.7 (52.0%)</td>
<td>33.0 (18.5%)</td>
</tr>
</tbody>
</table>

*NOTE: Net cumulative CO$_2$ injected = Cumulative CO$_2$ injected - Cumulative CO$_2$ produced
Table 3-33: Cumulative amount of CO$_2$ produced for different distances between CO$_2$ injector and brine injector after 100 years of observation (Figure 23-16, Appendix P)

<table>
<thead>
<tr>
<th>Distance between injectors</th>
<th>Cumulative CO$_2$ Produced (Mt)</th>
</tr>
</thead>
<tbody>
<tr>
<td>150 m</td>
<td>132.8</td>
</tr>
<tr>
<td>300 m</td>
<td>51.3</td>
</tr>
</tbody>
</table>

3.14.3 Distance between CO$_2$ Injector & Brine Producer

We finally vary the distance between the CO$_2$ injector and the brine producers, while keeping all the other parameters constant. The following distances are tested:

- 2,100 m
- 2,700 m

Figure 23-27 shows that we inject the full amount of cumulative supercritical CO$_2$ into the formation when the distance is 2,100 m. At larger distances the pressure relief effects of the brine producers are not felt. This raises the BHP of the CO$_2$ injector, resulting in a lower injection rate. Both Tables 3-34 & 3-35 show that increasing the distance between the CO$_2$ injector and the brine producers leads to a decrease in both the net cumulative amount of CO$_2$ injected and the cumulative CO$_2$ produced. Breakthrough occurs at around 7 years for 2,100 m and 18 years for 2,700 m. In addition, the cumulative amount of water injected and produced at 2,700 m is less than at 2,100 m (see Figures 23-36 to 23-39). This shows that the pressure relief effects are indeed minimised when the distance is increased.

There is a decrease in the percentage of residual trapping when the distance increases to 2,700m. This is because we inject a smaller amount, but with a larger plume radius. Figure 3-23 shows that the “surface area to volume ratio” increases, which also means that there is an increase in the percentage of dissolved CO$_2$.

Table 3-34: Summary of analysis for distance between CO$_2$ injector and brine producers after 100 years of observation (Figures 23-27, 23-28, 23-30 to 23-35, Appendix P)

<table>
<thead>
<tr>
<th>Distance between CO$_2$ injector &amp; brine producers</th>
<th>CO$_2$ state (Mass %)</th>
<th>*NET cumulative CO$_2$ injected (Mt)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Trapped (Mt)</td>
<td>Dissolved (Mt)</td>
</tr>
<tr>
<td>2,100 m</td>
<td>92.7 (52.0%)</td>
<td>33.0 (18.5%)</td>
</tr>
<tr>
<td>2,700 m</td>
<td>80.6 (50.8%)</td>
<td>32.5 (20.5%)</td>
</tr>
</tbody>
</table>

*NOTE: Net cumulative CO$_2$ injected = Cumulative CO$_2$ injected - Cumulative CO$_2$ produced
Table 3-35: Cumulative amount of CO$_2$ produced for different distances between CO$_2$ injector and brine producers after 100 years of observation (Figure 23-29, Appendix P)

<table>
<thead>
<tr>
<th>Distance between CO$_2$ injector &amp; brine producers</th>
<th>Cumulative CO$_2$ Produced (Mt)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2,100 m</td>
<td>51.3</td>
</tr>
<tr>
<td>2,700 m</td>
<td>7.1</td>
</tr>
</tbody>
</table>

We conclude that -

- SWAG enhances both residual and dissolution trapping by the counter-current flow of CO$_2$ and water. This encourages dissolution by counter-current flow diffusion and forced imbibition occurs early on during injection.
- Positioning the water injector and CO$_2$ injector closer together enhances dissolution trapping.
- Increasing the distance between the CO$_2$ injector and the brine producers delay CO$_2$ breakthrough.
- Increasing the perforation interval of the CO$_2$ injector as much as economically possible results in a higher overall trapping benefit.
- Careful well positioning is required for this design.
- More time and analysis of this design could avoid CO$_2$ production.
- The presence of low permeability layers minimises contact between water and CO$_2$ injected.
- As a result, this engineering design might not be best suited for this type of reservoir.
3.15 Online Well Sequence

We test out if the sequence in which wells are put online will have any effect on the trapping and the cumulative CO$_2$ injected. We use VWP 5 (refer to Figure 3-9) since it is our best vertical well scenario, injecting the highest amount of cumulative supercritical CO$_2$.

The work flow used when performing our analysis is -

- We start with 2 (or 3) injection wells which generally inject a lower cumulative amount of CO$_2$.
- After 2 years we add another 2 (or 3) wells which generally inject an average cumulative amount of CO$_2$.
- After 6 years, we add another 5 (or 3) injection wells, which generally inject a high amount of cumulative CO$_2$.
- We also try reversing the sequence (from high cumulative injection wells to low cumulative injection wells)
Although there are numerous possible combinations of online well sequences which can be generated. We test out a total of 5 different online sequences:

- **Base Case:**
  - All wells are placed online from the start.
- **Online sequence 1:**
  - CO2_5 & CO2_17 are online at the start.
  - CO2_11 & CO2_6 are online after 2 years.
  - CO2_10, CO2_12, CO2_16, CO2_7 & CO2_8 are online after 6 years.
- **Online sequence 2:**
  - CO2_5, CO2_17 & CO2_11 are online at the start.
  - CO2_12, CO2_6 & CO2_10 are online after 2 years.
  - CO2_16, CO2_7 & CO2_8 are online after 6 years.
- **Online sequence 3:**
  - CO2_10 & CO2_16 are online at the start.
  - CO2_12 & CO2_8 are online after 2 years.
  - CO2_5, CO2_6, CO2_7, CO2_11 & CO2_17 are online after 6 years.
- **Online sequence 4:**
  - CO2_8, CO2_10 & CO2_16 are online at the start.
  - CO2_7, CO2_11 & CO2_12 are online after 2 years.
  - CO2_5, CO2_6 & CO2_17 are online after 6 years.

Table 3-36: Summary of analysis for online well sequence after 100 years of observation (Figures 24-1 to 24-4, Appendix Q)

<table>
<thead>
<tr>
<th>Online Sequence</th>
<th>CO2 state (Mass %)</th>
<th>Cumulative CO2 injected (Mt)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Trapped (Mt)</td>
<td>Dissolved (Mt)</td>
</tr>
<tr>
<td>Base Case (all wells online from the start)</td>
<td>127.1 (56.5%)</td>
<td>66.6 (29.6%)</td>
</tr>
<tr>
<td>1</td>
<td>127.5 (56.5%)</td>
<td>66.3 (29.4%)</td>
</tr>
<tr>
<td>2</td>
<td>127.9 (56.7%)</td>
<td>66.7 (29.6%)</td>
</tr>
<tr>
<td>3</td>
<td>127.9 (56.9%)</td>
<td>66.5 (29.6%)</td>
</tr>
<tr>
<td>4</td>
<td>127.2 (56.6%)</td>
<td>66.5 (29.6%)</td>
</tr>
</tbody>
</table>

Table 3-36 shows that the sequence in which we bring wells online does not significantly affect the cumulative CO2 injected, residually trapped CO2 and dissolved CO2. With more data about reservoir properties, the effects of well sequencing might be more significant. However, if we rank each online sequence according to what they improve, we can say that:

- Online sequence 1 injects the highest amount of cumulative supercritical CO2.
- Online sequence 3 has the highest percentage of residually trapped CO2.
- All online sequences have a high percentage of dissolved CO2, except for online sequence 1.
- Online sequence 3 is the best in terms of both trapping effects.
4. Economics Methodology

This analysis compares the injection designs from an economic perspective. The reservoir simulations show that some injection designs show higher potential to trap residually and dissolve more CO₂ than others. However, there are also economic differences between these designs. We combine the trapping and economic benefits of each scenario into a single index. This enables us to compare injection designs from both trapping and economic viewpoints.

We estimate the Net Present Value (NPV) of different injection options. The NPV is the sum of discounted revenues and costs in each year of the injection project. We assume that the project owners receive revenue from injecting CO₂. Hypothetical carbon prices are assumed to obtain project revenues. We also make costs estimates for -

1. CO₂ injection and water production wells
2. CO₂ and water pipelines
3. A CO₂ booster station and water pumping facility
4. Seismic surveys and monitoring wells
5. Closing down after injection stops
6. Operating the injection site
7. Contingency and project management

We also estimate a trapping benefit index (TBI) to combine the effect of trapping. We use three versions of the TBI. Each has a different purpose. The first one is a simple version that measures only the absolute figures of residual and dissolution trapping. The second one takes into account the depth of mobile CO₂ and combines it with the first index. The third index measures the benefit of trapping CO₂ over time.

Finally, we combine NPVs and TBIs together to give single assessment of the combined economic and trapping attractiveness of different designs.

4.1 Economics Aim & Scope

The aim of the economic analysis is to estimate the relative economics of different injection schemes with different trapping results. The aim is not to assess the overall profitability of injection in absolute terms. Our economics use 9 injection wells to align the analyses with the reservoir simulations. We do not optimise the number and location of the wells to ensure that -

a. All available CO₂ is injected
b. No CO₂ is produced

We examine the economics of the injection designs only. The boundary of analysis is from the point of CO₂ distribution to the points of CO₂ injection in the site. We do not consider the economics of capture and transport from the source to the injection site. Figure 4-1 illustrates the boundary of our analyses - the Lesueur injection area.
4.2 Injection Surface Designs

We compare the economics of the injection designs listed below -

a. Vertical injection wells  
b. Horizontal injection wells  
c. Vertical injection and water production wells  
d. Water alternate gas injection and water production wells

We fix the following parameters for the injection designs compared -

a. A perforation depth at layer 56 (Mid Wonnerup)  
b. A perforation interval of 500 metres for vertical wells and 2,000 metres for horizontal wells

For the Water Alternate Gas case, repeated cycles each with 1 year of gas injection followed by 1 year of water injection. The injection schemes are illustrated in Figures 4-2 to 4-5.
For the Water Alternate Gas case, the water injection pipelines (from the booster station to injection wells) are based on the same design as the CO$_2$ injection pipelines. However, for simplicity, they are not shown on the map.

Figure 4-2: Vertical injection wells
Figure 4-3: Horizontal injection wells

Figure 4-4: Vertical injection & production wells
4.3 Economic Benefits

We estimate NPVs as measures of the economic benefits of the injection designs. The NPVs measure the net economic benefit of injecting CO$_2$ in real terms in A$ 2014$. We assume revenue from injection at a range of hypothetical carbon prices at the injection site (zero to A$ 50 per tonne). The NPV also takes into account the real costs of injecting CO$_2$ in A$ 2014$. 

The following assumptions are taken into account for calculating the Net Present value -

- We calculate NPVs at 1 January 2014 using a 7% discount rate.
- NPVs and costs are in real terms in A$ 2014$.
- Hypothetical carbon benefit/price = A$0, 10, 25 and 50 per tonne injected.
- The hypothetical carbon benefit/price is the price received at the injection site, not at the point of capture.

4.4 Injection Profiles

Figures 4-6 to 4-9 show the CO$_2$ injection rates from the reservoir simulation results for each injection design. We assume 40 years of injection and estimate the CO$_2$ trapped after 140 years from injection start.

We need CO$_2$ injection rates as an input to the economic analysis to estimate the revenue from injecting CO$_2$ at the hypothetical carbon prices set out above. This means that those designs that inject less CO$_2$ yield less revenue. The injection rates
shows the net CO\textsubscript{2} stored, so CO\textsubscript{2} breakthrough into production wells for the water production cases is subtracted from the gross CO\textsubscript{2} injected.

**Figure 4-6:** Vertical wells injection profiles

**Figure 4-7:** Horizontal wells injection profile
Figure 4-8: Vertical injection & water production wells profile

Figure 4-9: Water alternate gas injection & water production wells profile
4.5 Assumed Investment Phasing

Table 4-1 sets out our assumptions for the timing of investment. We assume 2 years of research & planning. This period should be enough to collect data required from various sources such as exploration wells and seismic data. Then another year is assumed for Front End Engineering Design (FEED). We assume that a decision to drill wells and construct pipelines and other facilities starts in 2017. Injection is assumed to last for 40 years. Each injection design has its own injection profile as shown in Figures 26-1 to 26-4. Finally, the project is closed down in year 2058. Our analyses exclude any activity monitoring beyond this time.

Table 4-1: Investment phasing assumed for economic analysis

<table>
<thead>
<tr>
<th></th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
<th>...</th>
<th>2058</th>
</tr>
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<tbody>
<tr>
<td>Research &amp; Planning</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Front End Engineering Design</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wells + Pipelines</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Remaining Wells + Pipelines</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Injection Starts</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Injection Continues for 40 years</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Closing Down</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

4.6 Cost Estimating Assumptions

Our cost estimating assumptions are set out below. Refer to Appendix S for the detailed economic analyses. Again, we emphasise that the aim of the economic analysis is to estimate the relative economics of different injection schemes with different trapping results. We do not assess the overall profitability of injection in absolute terms. Changing costs, such as seismic survey costs or abandonment costs, would affect the absolute NPV and NPV x TBI results of each injection design. However, this would not change the relative economic ranking. This is because the same seismic survey cost, frequency of seismic survey and the same method for calculating abandonment costs were used for each injection design.

4.6.1 Well Costs

These are the well drilling cost assumptions:

- The well drilling rig rate is A$45,000 per day in real A$ 2014 terms.
- The vertical drilling penetration rate is 61 metres/day.
- The horizontal drilling penetration rate is 45 metres/day.
- The mobilisation and demobilisation ("Mob/Demob") time is 10 days per well.
- Mob/Demob cost is A$450,000 per well.
- Other tangible and intangible costs vary according to each well’s measured depth.

Table 4-2 and Table 4-3 show a comparison between the cost of a vertical and a horizontal well. This example shows that the cost of a horizontal well is approximately double that of a vertical well. This is because the penetration rate for
horizontal drilling is slower than for vertical drilling, which increases rig time. In addition, all horizontal sections of the horizontal wells are assumed to be 2,000 metres. Therefore the measured depth of horizontal wells is significantly higher than that for vertical wells. Tangible and intangible costs for exploration and injection wells are based on Schlumberger’s technical note 3 (Mat Fiah & Sagheb 2011). Water production wells are based on a similar estimating approach except that they exclude the cost of conversion to an injection well.

Table 4-2: Well design example

<table>
<thead>
<tr>
<th></th>
<th>Vertical Well</th>
<th>Horizontal Well</th>
</tr>
</thead>
<tbody>
<tr>
<td>Measured Depth (metres)</td>
<td>2,247</td>
<td>3,837</td>
</tr>
<tr>
<td>Vertical Drilling Rate of Penetration (metres/day)</td>
<td></td>
<td>61</td>
</tr>
<tr>
<td>Horizontal Drilling Rate of Penetration (metres/day)</td>
<td></td>
<td>35</td>
</tr>
<tr>
<td>Well Drilling Rig Rate (A$/day)</td>
<td></td>
<td>45,000</td>
</tr>
<tr>
<td>Drilling (days)</td>
<td>37</td>
<td>89</td>
</tr>
<tr>
<td>Mob/Demob Time (days)</td>
<td>10</td>
<td>10</td>
</tr>
</tbody>
</table>

Table 4-3: Well cost estimate example

<table>
<thead>
<tr>
<th></th>
<th>Vertical Well</th>
<th>Horizontal Well</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Tangible Costs</td>
<td>1.1</td>
<td>1.6</td>
</tr>
<tr>
<td>Total Intangible Costs</td>
<td>4.6</td>
<td>9.2</td>
</tr>
<tr>
<td>Contingency / Safety factor</td>
<td>0.8</td>
<td>1.6</td>
</tr>
<tr>
<td>Conversion from an Exploration to an Injection Well</td>
<td>1.1</td>
<td>2.0</td>
</tr>
<tr>
<td>Total Estimated Cost</td>
<td>7.6</td>
<td>14.4</td>
</tr>
</tbody>
</table>

4.6.2 Pipeline Costs

The CO₂ and water pipeline costs are estimated based on the following parameters -

- Pipeline nominal diameter (inch)
- Pipeline length (km)
- Steel quantity (tonne/km)
- Coating surface (m²/km)
The CO₂ pipeline diameters are picked based on the following -

- Inlet and outlet pressures (mega Pascals)
- Length of each pipeline from the booster station to each wellhead (kilometre)
- Maximum mass flow rate in the pipeline (tonnes/day)
- Fluid density in the pipeline (kilogram/cubic metres)
- Fluid viscosity in the pipeline (Pascal-seconds)

We assume that the inlet pressure is 21.5 mega Pascals (Worley Parsons 2011) and the outlet pressure is 17 mega Pascals. The outlet pressure at the wellhead should be sufficient to inject the CO₂ (Marmin 2011). The length of each pipeline is based on the injection designs in Figures 4-2 to 4-5. The maximum mass flow rates for each well are predicted from the reservoir simulation results (Figures 4-6 to 4-9). The fluid density and viscosity are estimated according to fluid type, pressure and temperature.

The following set of equations are used to estimate the pipeline diameter (McCollum & Ogden 2006) -

\[ P_{inter} = \frac{(P_{in} + P_{out})}{2} \]

where,

- \( P_{inter} \) is intermediate pipeline pressure (mega Pascals)
- \( P_{in} \) is inlet pipeline pressure (mega Pascals)
- \( P_{out} \) is outlet pipeline pressure (mega Pascals)

\[ Re = \frac{1.8227 \times m}{\pi \times \mu \times D_{assum}} \]

where,

- \( Re \) is Reynolds number
- \( m \) is mass flow rate in the pipeline (tonnes/day)
- \( \mu \) is the viscosity of the fluid in the pipeline (Pascal-seconds)
- \( D_{assum} \) is an assumed pipeline diameter

\[ F_t = \left[ \frac{1}{4 \times \left[ -1.8 \log_{10} \left( \frac{6.91}{R_e} + \left( \frac{12 \times \varepsilon}{D_{assum}^{1.11}} \right) \right] \right]^2} \]

where,

- \( F_t \) is the friction factor
- \( \varepsilon \) is the pipeline roughness factor (feet)
where,

$D$ is the pipeline diameter (inches)

$\rho$ is the density of the fluid in the pipeline (kilogram/cubic metre)

$\Delta P$ is the pressure drop in the pipeline, $P_{in} - P_{out}$ (mega Pascals)

$L$ is the pipeline length (kilometre)

The diameters for CO$_2$ and water pipelines vary from 4 to 16 inches. The steel quantity and coating required for each pipeline is then estimated using the data in Table 4-4. We choose ANSI Class 1500 for all CO$_2$ pipelines because it can handle operating pressures up to 25.5 Mega Pascals. We choose ANSI Class 150 for water pipelines. Finally, the cost of manufacture & delivery and construction & installation for every pipeline is calculated based on the algorithm given in Appendix T.

The pipeline cost varies from A$30,354 to 47,932 per km-inch in A$2014 terms depending on the grade.

**Table 4-4: Carbon steel pipeline design**

<table>
<thead>
<tr>
<th>Pipeline grade per API SL code</th>
<th>X-65</th>
<th>&quot;X85&quot; Denotes minimum yield strength of 65,000 psi etc. Wall thickness per AS2885-1997. Part 1, Clause 4.3.4</th>
</tr>
</thead>
<tbody>
<tr>
<td>S</td>
<td>448</td>
<td>MPa (abs)</td>
</tr>
<tr>
<td>E</td>
<td>1.0</td>
<td>Weld Joint Factor</td>
</tr>
<tr>
<td>F</td>
<td>0.72</td>
<td>Design Factor</td>
</tr>
<tr>
<td>C</td>
<td>0.0</td>
<td>Corrosion Allowance</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>ANSI Class of Fittings</th>
<th>ANSI flange rating (MPag)</th>
<th>PipeLine MAWP (MPag)</th>
<th>Pipeline MAwP (psi)</th>
<th>wt. mm</th>
<th>ID. mm</th>
<th>tonne/km</th>
<th>wt. mm</th>
<th>ID. mm</th>
<th>tonne/km</th>
<th>wt. mm</th>
<th>ID. mm</th>
<th>tonne/km</th>
</tr>
</thead>
<tbody>
<tr>
<td>10</td>
<td>114.3</td>
<td>10</td>
<td>359</td>
<td>1.8</td>
<td>119.8</td>
<td>5.0</td>
<td>2.7</td>
<td>108.8</td>
<td>7.5</td>
<td>4.5</td>
<td>105.2</td>
<td>12.2</td>
</tr>
<tr>
<td>15</td>
<td>160.3</td>
<td>22</td>
<td>529</td>
<td>2.7</td>
<td>162.9</td>
<td>10.9</td>
<td>4.0</td>
<td>160.3</td>
<td>16.2</td>
<td>6.7</td>
<td>154.9</td>
<td>26.9</td>
</tr>
<tr>
<td>20</td>
<td>219.1</td>
<td>38</td>
<td>688</td>
<td>3.5</td>
<td>212.1</td>
<td>18.5</td>
<td>5.2</td>
<td>206.6</td>
<td>27.5</td>
<td>8.7</td>
<td>201.7</td>
<td>44.9</td>
</tr>
<tr>
<td>25</td>
<td>273.0</td>
<td>59</td>
<td>858</td>
<td>4.4</td>
<td>264.3</td>
<td>28.8</td>
<td>6.5</td>
<td>250.0</td>
<td>42.7</td>
<td>10.8</td>
<td>251.3</td>
<td>65.9</td>
</tr>
<tr>
<td>30</td>
<td>323.9</td>
<td>82</td>
<td>1,018</td>
<td>5.2</td>
<td>313.5</td>
<td>40.5</td>
<td>7.7</td>
<td>306.4</td>
<td>61.1</td>
<td>12.8</td>
<td>298.2</td>
<td>96.1</td>
</tr>
<tr>
<td>35</td>
<td>365.6</td>
<td>99</td>
<td>1,117</td>
<td>5.7</td>
<td>344.2</td>
<td>49.8</td>
<td>8.5</td>
<td>336.0</td>
<td>72.4</td>
<td>14.1</td>
<td>327.4</td>
<td>118.3</td>
</tr>
<tr>
<td>40</td>
<td>408.4</td>
<td>130</td>
<td>1,277</td>
<td>6.5</td>
<td>393.4</td>
<td>63.8</td>
<td>9.7</td>
<td>387.0</td>
<td>94.5</td>
<td>16.1</td>
<td>372.4</td>
<td>154.5</td>
</tr>
<tr>
<td>45</td>
<td>457.0</td>
<td>164</td>
<td>1,436</td>
<td>7.3</td>
<td>442.4</td>
<td>80.6</td>
<td>10.9</td>
<td>435.2</td>
<td>119.6</td>
<td>18.1</td>
<td>429.7</td>
<td>195.4</td>
</tr>
<tr>
<td>50</td>
<td>508.0</td>
<td>203</td>
<td>1,596</td>
<td>8.1</td>
<td>491.8</td>
<td>99.6</td>
<td>12.1</td>
<td>483.7</td>
<td>147.7</td>
<td>26.2</td>
<td>487.7</td>
<td>241.4</td>
</tr>
<tr>
<td>55</td>
<td>569.0</td>
<td>245</td>
<td>1,756</td>
<td>8.9</td>
<td>541.1</td>
<td>120.6</td>
<td>13.3</td>
<td>532.3</td>
<td>176.9</td>
<td>22.2</td>
<td>514.6</td>
<td>292.3</td>
</tr>
<tr>
<td>60</td>
<td>630.0</td>
<td>292</td>
<td>1,916</td>
<td>9.7</td>
<td>590.5</td>
<td>143.7</td>
<td>14.6</td>
<td>580.9</td>
<td>213.0</td>
<td>24.2</td>
<td>561.8</td>
<td>348.1</td>
</tr>
<tr>
<td>65</td>
<td>660.0</td>
<td>342</td>
<td>2,073</td>
<td>10.6</td>
<td>638.9</td>
<td>162.9</td>
<td>16.8</td>
<td>628.6</td>
<td>249.4</td>
<td>26.2</td>
<td>607.6</td>
<td>407.5</td>
</tr>
<tr>
<td>70</td>
<td>711.0</td>
<td>397</td>
<td>2,234</td>
<td>11.4</td>
<td>688.3</td>
<td>195.2</td>
<td>17.0</td>
<td>677.0</td>
<td>289.4</td>
<td>28.2</td>
<td>654.6</td>
<td>472.9</td>
</tr>
<tr>
<td>75</td>
<td>762.0</td>
<td>456</td>
<td>2,394</td>
<td>12.2</td>
<td>737.7</td>
<td>224.2</td>
<td>18.2</td>
<td>725.6</td>
<td>332.4</td>
<td>30.2</td>
<td>701.5</td>
<td>543.2</td>
</tr>
<tr>
<td>80</td>
<td>813.0</td>
<td>519</td>
<td>2,554</td>
<td>13.0</td>
<td>787.0</td>
<td>255.2</td>
<td>19.4</td>
<td>774.2</td>
<td>378.4</td>
<td>32.3</td>
<td>748.5</td>
<td>614.8</td>
</tr>
<tr>
<td>85</td>
<td>864.0</td>
<td>586</td>
<td>2,714</td>
<td>13.8</td>
<td>836.4</td>
<td>298.2</td>
<td>20.6</td>
<td>822.7</td>
<td>427.3</td>
<td>34.3</td>
<td>795.5</td>
<td>698.4</td>
</tr>
<tr>
<td>90</td>
<td>914.0</td>
<td>656</td>
<td>2,871</td>
<td>14.6</td>
<td>884.8</td>
<td>322.5</td>
<td>21.8</td>
<td>870.3</td>
<td>478.2</td>
<td>36.3</td>
<td>841.5</td>
<td>761.5</td>
</tr>
<tr>
<td>95</td>
<td>964.0</td>
<td>726</td>
<td>3,029</td>
<td>15.4</td>
<td>932.2</td>
<td>359.5</td>
<td>23.0</td>
<td>918.0</td>
<td>535.2</td>
<td>38.3</td>
<td>887.5</td>
<td>827.6</td>
</tr>
<tr>
<td>100</td>
<td>1067.0</td>
<td>942</td>
<td>3,352</td>
<td>17.0</td>
<td>1032.9</td>
<td>439.6</td>
<td>26.5</td>
<td>1016.0</td>
<td>651.7</td>
<td>42.3</td>
<td>982.3</td>
<td>1065.1</td>
</tr>
</tbody>
</table>

Table 4-5 and Table 4-6 show an example that compares the design and cost of a CO$_2$ pipeline to a water pipeline.
Table 4-5: Pipeline design example

<table>
<thead>
<tr>
<th></th>
<th>CO₂ Pipeline</th>
<th>Water Pipeline</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fluid Mass Rate</td>
<td>12,825</td>
<td>9,083</td>
</tr>
<tr>
<td>Pipeline Length</td>
<td>15</td>
<td>12</td>
</tr>
<tr>
<td>Pipeline Diameter</td>
<td>14</td>
<td>12</td>
</tr>
<tr>
<td>ANSI Class</td>
<td>1500</td>
<td>150</td>
</tr>
<tr>
<td>Unit Cost</td>
<td>637</td>
<td>408</td>
</tr>
<tr>
<td>Maximum Operating Pressure</td>
<td>25.5</td>
<td>10.2</td>
</tr>
</tbody>
</table>

Table 4-6: Pipeline cost example (A$ MM 2014)

<table>
<thead>
<tr>
<th></th>
<th>CO₂ Pipeline</th>
<th>Water Pipeline</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pipeline Manufacture &amp; Delivery</td>
<td>5.0</td>
<td>1.9</td>
</tr>
<tr>
<td>Construction &amp; Installation</td>
<td>4.3</td>
<td>3.0</td>
</tr>
<tr>
<td>Total Estimated Cost</td>
<td>9.3</td>
<td>4.9</td>
</tr>
</tbody>
</table>

4.6.3 CO₂ Booster Station

All data related to the CO₂ booster station are taken from Worley Parson’s report (2011). The aim of the booster station is to collect the entire CO₂ stream from different sources and pump it to the wellheads. Table 4-7 give details of the design and cost of the station.

Table 4-7: CO₂ booster station design & cost

<table>
<thead>
<tr>
<th></th>
<th>CO₂ Booster Station + Heater</th>
</tr>
</thead>
<tbody>
<tr>
<td>Outlet Pressure</td>
<td>21.5</td>
</tr>
<tr>
<td>(Mega Pascals)</td>
<td></td>
</tr>
<tr>
<td>Power (Mega Watts)</td>
<td>11.0</td>
</tr>
<tr>
<td>Estimated Cost</td>
<td>67.6</td>
</tr>
<tr>
<td>(A$MM 2014)</td>
<td></td>
</tr>
</tbody>
</table>

Note: A$MM is million Australian dollars
4.6.4 Monitoring Costs

We also take monitoring costs into consideration. However these costs remain the same for all injection designs. Seismic surveys are repeated every 5 years to track the progress of the CO₂ plume. We assume 1 short monitoring well and 1 deep monitoring well for each CO₂ injection well. This assumption is based on Schlumberger’s technical note 3 (Fiah et. al. 2011). All injection designs include 9 CO₂ injection wells. Therefore there are 9 shallow and 9 deep monitoring wells for all designs.

We estimate the cost of a seismic survey by the surface area to be surveyed. We assume that the seismic survey costs A$12,750 per square kilometre, and that the surface area of the reservoir is approximately 220 square kilometres. So the cost of a seismic survey for this study is about A$ 2.8 MM. Cost of a short monitoring well is A$MM 2.5, and a deep monitoring well cost is estimated to be A$7.9 MM.

Table 4-8: Monitoring cost design & costs

<table>
<thead>
<tr>
<th></th>
<th>Seismic Survey</th>
<th>Short Monitoring Well</th>
<th>Deep Monitoring Well</th>
</tr>
</thead>
<tbody>
<tr>
<td>Frequency</td>
<td>Repeated every 5 years</td>
<td>1 for every CO₂ injection well</td>
<td>1 for every CO₂ injection well</td>
</tr>
<tr>
<td>Estimated Cost (A$MM 2014)</td>
<td>2.8</td>
<td>2.5</td>
<td>7.9</td>
</tr>
</tbody>
</table>

4.6.5 Closing down Costs

Closing down costs take into account decommissioning injection wells and other injection-related surface facilities after injection stops. Monitoring wells are not included in closing down costs because we assume that monitoring wells will keep operating after injection ceases. In addition, closing down costs do not only occur at the end of the project. We replace the CO₂ booster station and water handling facilities after 25 years of operation. Therefore the closing down costs of the facilities replaced are included in year 2042.

We estimate the closing down cost of an injection well is A$0.08 MM. We assume that the closing down costs for pipelines is 3% of original capital cost and 10% of original capital cost for other surface facilities.

Table 4-9: Closing down costs

<table>
<thead>
<tr>
<th></th>
<th>Wells</th>
<th>Facilities</th>
<th>Pipelines</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.08 A$MM per well</td>
<td>10% of Original Capex</td>
<td>3% of Original Capex</td>
<td></td>
</tr>
</tbody>
</table>
4.6.6 Capital Cost Estimates for each Case

Table 4-10 shows the breakdown of capital costs for each case.

**Table 4-10: Capital cost estimates for each case (A$ MM 2014)**

<table>
<thead>
<tr>
<th></th>
<th>Vertical Wells</th>
<th>Horizontal wells</th>
<th>Water Production</th>
<th>Water Alternating Gas</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wells</td>
<td>70</td>
<td>131</td>
<td>107</td>
<td>107</td>
</tr>
<tr>
<td>Well Work-over</td>
<td>117</td>
<td>117</td>
<td>182</td>
<td>182</td>
</tr>
<tr>
<td>Pipelines</td>
<td>16</td>
<td>10</td>
<td>28</td>
<td>43</td>
</tr>
<tr>
<td>Booster Stations</td>
<td>135</td>
<td>135</td>
<td>135</td>
<td>135</td>
</tr>
<tr>
<td>Water Treatment &amp; Pumping</td>
<td>0</td>
<td>0</td>
<td>12</td>
<td>12</td>
</tr>
<tr>
<td>Monitoring</td>
<td>116</td>
<td>116</td>
<td>116</td>
<td>116</td>
</tr>
<tr>
<td>Closing Down</td>
<td>15</td>
<td>15</td>
<td>16</td>
<td>17</td>
</tr>
<tr>
<td>Project Management, Owner’s Cost and Contingency</td>
<td>119</td>
<td>139</td>
<td>141</td>
<td>146</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>588</strong></td>
<td><strong>663</strong></td>
<td><strong>737</strong></td>
<td><strong>758</strong></td>
</tr>
</tbody>
</table>

Indirect capital costs such as project management, owner’s cost and contingency are also considered, at 15%, 7% and 10% respectively.

4.6.7 Other Costs

The real annual operating costs of the injection project are assumed to be 5% of the total real capital costs.
5. Techno-Economic Analysis

5.1 Trapping Benefit Indices

The aim of Trapping Benefit Indices (TBIs) is to quantify the effects of residual and dissolution trapping for the injection designs considered. We use three versions of the TBI. We discuss these below.

5.1.1 Trapping Benefit Index 1 (TBI1)

TBI1 is the fraction of total CO₂ mass injected in the following phases -

a) Residual gas
b) Dissolved in water

TBI1 is measured after 140 years.

For a hypothetical example injection design -

a) Total CO₂ injected = 260 Mt
b) Residual + Dissolved CO₂ = 200 Mt

TBI1 = 200 / 260 = 0.77

TBI1 values can only be compared with the TBI1 values of other injection cases.

5.1.2 Trapping Benefit Index 2 (TBI2)

TBI2 is similar to TBI1. However TBI2 also includes the effect of the vertical distribution of mobile CO₂. This takes into account the risk of leakage if mobile CO₂ occupies layers closer to the surface. TBI1 and TBI2 should not be compared with each other in absolute terms. TBI2 values can only be compared with the TBI2 values of other injection cases.

The aim of the Trapping Benefit Index 2 (TBI2) is to take into account both -

a) Residual and dissolution trapping (the same as TBI1)
b) The vertical distribution of mobile CO₂ across the layers

We calculate a mobile CO₂ risk factor in order to compare the vertical distribution of mobile CO₂ for different injection designs. The risk factor increases linearly from 0 (deepest layer or the safest layer) to 1 (shallowest layer or the most risky layer). The risk factor gives an advantage to cases that show less CO₂ in the shallower layers.

The petrel model has 187 layers. These and their corresponding risk factors are shown in Figure 5-1.
For a hypothetical example injection design -

a) Total CO$_2$ injected = 260 Mt

b) Residual + Dissolved CO$_2$ = 200 Mt

c) Mobile CO$_2$ = 60 Mt

- Assuming that all mobile CO$_2$ resides in layer 1

Depth-weighed benefit for mobile CO$_2$ = 60 - (60*1) = 0

TBI2 = (200 + 0)/260 = 0.77
• Assuming that all mobile CO\(_2\) resides in layer 93
Depth-weighed benefit for mobile CO\(_2\) = 60 - (60*0.5) = 30
TBI2 = (200 + 30)/260 = 0.88

• Assuming that all mobile CO\(_2\) resides in layer 187
Depth-weighed benefit for mobile CO\(_2\) = 60 - (60*0) = 60
TBI2 = (200 + 60)/260 = 1

5.1.3 Trapping Benefit Index 3 (TBI3)
TBI3 includes the benefits of trapping during the injection period taking trapping timing into account. Figure 5-2 shows the changes of TBI1 over time. TBI3 is the present value of the 140 year profile of TBI1s at 1 Jan 2014 using a 7% real discount rate. 7% is the same real discount rate that we use to calculate the NPVs. We then normalise the result by dividing by 6 (simply to ensure that the result is less than 1 for presentation purposes).

We cannot compare TBI3 with TBI1 and TBI2. However, we can compare the TBI3s of the different injection cases. TBI3 only shows the relative benefit of trapping (TBI1) over time. It does not have any meaning in absolute terms.

Figure 5-2: Trapping Benefit Index 1 vs. Time
5.1.4 Comparison between Trapping Benefit Indices

Table 5-1 and Figure 5-3 show how the values of each Trapping Benefit Index vary with different injection cases. Again, we cannot compare the indices with each other, but we can compare each index for different injection cases.

Table 5-1: Comparison between Trapping Benefit Indices

<table>
<thead>
<tr>
<th></th>
<th>Vertical Wells</th>
<th>Horizontal wells</th>
<th>Water Production</th>
<th>Water Alternating Gas</th>
</tr>
</thead>
<tbody>
<tr>
<td>TBI1</td>
<td>0.86</td>
<td>0.85</td>
<td>0.88</td>
<td>0.92</td>
</tr>
<tr>
<td>TBI2</td>
<td>0.90</td>
<td>0.88</td>
<td>0.92</td>
<td>0.94</td>
</tr>
<tr>
<td>TBI3</td>
<td>0.65</td>
<td>0.67</td>
<td>0.66</td>
<td>0.97</td>
</tr>
</tbody>
</table>

Figure 5-3: Comparison between Trapping Benefit Indices
5.2 Combining NPVs and TBIs

Ideally we would attempt to place a monetary value on the TBIs so that we can combine easily the trapping benefits with the NPVs. This would give the combined economic and trapping benefits. However, converting the TBIs to monetary values is extremely difficult. Therefore, we leave the TBIs in the form of simple dimensionless indices and multiply them by the NPVs.

To show the combined benefits of NPV and TBI, we -

(a) Multiply a positive NPV with (TBI1 or TBI2)
(b) Multiply a negative NPV with (1 - TBI1 or TBI2)
(c) Multiply a positive NPV with TBI3
(d) Multiply a negative NPV with (1 - TBI3)

5.3 Results and Discussion

5.3.1 Results and Discussion for NPV differences

The reasons for the NPV differences shown in Figure 5-4 are set out in Table 5-2.
Table 5-2: Discussion of NPV differences

<table>
<thead>
<tr>
<th>Injection Design</th>
<th>Vertical Wells</th>
<th>Horizontal Wells</th>
<th>Water Production</th>
<th>Water Alternate Gas (WAG)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lowest CAPEX and OPEX</td>
<td></td>
<td>Least amount</td>
<td>Higher CAPEX and OPEX because of -</td>
<td>Highest CAPEX and OPEX to produce, re-inject and dispose of water</td>
</tr>
<tr>
<td>Highest injectivity</td>
<td></td>
<td>injected, but much lower CAPEX and OPEX than water production and WAG designs</td>
<td>(a) water wells, and (b) water pipelines for water gathering and disposal</td>
<td>Injectivity reduced because of water injection</td>
</tr>
</tbody>
</table>

5.3.2 Results and Discussion for TBI1

Figure 5-5 shows that, for a carbon price of A$25 per tonne, injection through vertical wells has the highest NPV and an intermediate TBI. Injection with Water Alternate Gas (WAG) wells has the lowest NPV and the highest TBI.

![Figure 5-5: NPV vs. TBI1 for A$25 / tonne at injection site](image-url)
Figure 5-6 gives similar results. However, this figure shows NPVs calculated at a carbon price of zero A$ / tonne. Therefore, it only shows the present value of costs because there is no revenue. Figure 5-6 shows that injection through vertical wells has the lowest cost, while WAG injection has the highest cost.

Assuming a zero carbon price does not quantify the disadvantages of -

a) CO₂ production (water cases) and
b) low injectivity,

because they cannot include the effect of reduced revenue.

![Figure 5-6: NPV vs. TBI for A$0 / tonne at injection site](image)

Figure 5-7 displays the TBI1 multiplied by the NPV for each case. It shows that cases with higher TBIs become less relatively unattractive with higher carbon prices.
Figure 5-7: NPV x TBI for different scenarios

TBI1 is the fraction of residual and dissolved CO₂ of the total CO₂ stored as shown in Figure 5-8. The reasons for the TB1 differences are set out in Table 5-3, this table summarizes what was already mentioned in Section 3.
Figure 5-8: CO₂ mass percent in each phase for different scenarios

*: Total mass of CO₂ injected

Table 5-3: Discussion of TBI1

<table>
<thead>
<tr>
<th>Injection Design</th>
<th>Vertical Wells</th>
<th>Horizontal Wells</th>
<th>Water Production</th>
<th>Water Alternate Gas (WAG)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base case for explanation / comparison</td>
<td>0.86</td>
<td>0.85</td>
<td>0.88</td>
<td>0.92</td>
</tr>
<tr>
<td></td>
<td>Horizontal wells cannot intersect the sand zones between shale layers, so CO₂ does not contact with water as efficiently as in vertical wells</td>
<td>Pressure difference between CO₂ injectors and water producers drags the CO₂ plume towards production wells and enhances both trapping mechanisms</td>
<td>Cyclical water and gas injection improves CO₂ dissolution in water considerably</td>
<td></td>
</tr>
</tbody>
</table>
5.3.3 Results and Discussion for TBI2

Figures 5-9, 5-10, and 5-11 show the results for TBI2.

**Figure 5-9: NPV vs. TBI2 for A$25/tonne at injection site**

**Figure 5-10: NPV vs. TBI2 for A$0/tonne at injection site**
TBIs are close to TBIs. The main difference is that TB2 gives a lower advantage for the WAG case because a greater proportion of mobile CO$_2$ is left in the upper layers. Under WAG injection, the water injection cycle raises the bottom hole pressure. Therefore, during CO$_2$ injection, CO$_2$ cannot be injected through the deeper perforations. Refer to Figure 5-3 to compare values for TB2.
5.3.4 Results and Discussion for TBI3

Figures 5-12 and 5-13 show that vertical, horizontal and water production cases have very close Trapping Benefit Indices. Water Alternate Gas has the highest TBI with a big margin.

![Graph showing NPV vs. TBI3 for A$25 / tonne at injection site](image)

*Figure 5-12: NPV vs. TBI3 for A$25 / tonne at injection site*
Figure 5-13: NPV vs. TBI3 for A$/ tonne at injection site

Figure 5-14 shows that the WAG case is better than the vertical wells case at all carbon prices.

Figure 5-14: NPV x TBI3 for different scenarios
TBI3 brings the timing of trapping into account. WAG injection traps CO$_2$ earlier than the other cases. Because of this, TBI3 advantages the WAG case. The residual trapping benefits for the non-WAG cases are realised after injection stops (after year 40). Therefore, the differences between the present values of the trapping benefits for the non-WAG cases are very low. Refer to Figure 5-3 to compare values for TBI3.

5.4 Limitations

There are uncertainties in -

a) the geological model (porosity, permeability, layering, etc.)
b) fault modelling
c) the carbon benefit/price
d) capital and operating cost estimates
e) timing of development and injection
f) injection rate

Grid refinement across more of the reservoir would give better estimations of the amount of -

a) Injected CO$_2$
b) Residually Trapped CO$_2$
c) Dissolved CO$_2$

We have not optimised well numbers and well locations for specific designs to be able to -

a) Inject the total amount of CO$_2$ set for the project.
b) Prevent any CO$_2$ production in the water cases.

Taking these into account might change our absolute economic and trapping benefit estimates. However, in our view, they are unlikely to affect the ranking of the cases.
6. Conclusions

6.1 Fault Sensitivity

An increase in the transmissibility of the faults in the reservoir results in a plume with a smaller surface area to volume ratio. We inject more cumulative CO$_2$ (27% increase) because pressure build-up is slower. The percentage of residual trapping increases negligibly, while dissolution trapping decreases by about 5%.

6.2 Barrier between Yalgorup & Wonnerup

When we place a barrier in between the Yalgorup and Wonnerup Formation, pressure also does not dissipate easily. We inject a lower cumulative amount of CO$_2$ (a 9% decrease). The percentage of residual trapping decreases by about 1%, while dissolution trapping decreases by about 1%. This is because the CO$_2$ plume has slightly less contact with brine as it cannot rise as much. As a result, less residually is trapped CO$_2$ behind the plume.

6.3 High Permeability Streak

When we place a high permeability streak in the reservoir, we inject more CO$_2$ (3% increase). When we increase the streak’s permeability, pressure dissipates more easily. The percentage of residually trapped CO$_2$ changes by 1%, while dissolution trapping increases by 3%. This is because the CO$_2$ plume spreads out more laterally, allowing a larger surface area to contact the brine. Because of the high permeability streak, CO$_2$ tends to flow through that streak rather than rise upwards, leaving less residually trapped CO$_2$ behind the rising plume.

6.4 Salinity & Salting-out

6.4.1 Salinity

Increasing salinity from 48,000 ppm to 80,000 ppm, we inject a lower amount of cumulative CO$_2$ (7% decrease) because of the increased hydrostatic pressure. This also results in an 8% increase in residually trapped CO$_2$. However, the percentage of dissolution decreases by about 13% as salinity increases. This phenomenon is reported in several published papers.

6.4.2 Salting-out

When we activate salting-out, there is a negligible decrease in cumulative CO$_2$ injected. In addition, the percentage of residually trapped CO$_2$ increases negligibly. Salt particles form around the perforation, causing BHP to rise quickly, reaching maximum BHP in a shorter period. In addition, imbibition will occur around the area where salt has precipitated, resulting in a higher amount of residually trapped CO$_2$. The percentage dissolution decreases by about 1%. This is because the plume is unable to spread laterally from the lower injection rate.

6.5 Absolute Permeability

Doubling the absolute permeability of the entire reservoir, we inject more CO$_2$ (19% increase). Increasing absolute permeability allows pressure to dissipate more easily.
The percentage of residual trapping increases by roughly 4\%, while dissolution trapping decreases by 3\%. This is because the surface area to volume ratio is smaller.

6.6 Capillary Pressure

When we take capillary pressure into account, we inject less cumulative CO\textsubscript{2} (5\% decrease). The percentage of residually tapped CO\textsubscript{2} increases by about 1\%. This happens because we require a higher BHP to inject the CO\textsubscript{2} into the reservoir. Furthermore, we need a higher pressure to displace the wetting fluid (brine) with non-wetting fluid (CO\textsubscript{2}). As a result, residual trapping occurs more easily. The percentage of dissolution trapping increases by approximately 2\%, because we inject less CO\textsubscript{2}. This gives a higher surface area to volume ratio.

6.7 Vertical Well Placement

We test our different vertical well placements and find a maximum change of 7\% in the cumulative CO\textsubscript{2} injected. The percentage of residually trapped CO\textsubscript{2} changes by roughly 3\%, while dissolution trapping changes by 4\%. This occurs because placing wells in different surrounding environments result in changes to plume shape and contact with brine.

6.8 Local Grid Refinement

When we refine the grids in the Z direction we notice no significant changes. However, refining grids locally in the X & Y direction we inject more cumulative CO\textsubscript{2} (12\% increase). The percentage of dissolution trapping decreases by about 7\%, while residual trapping fluctuates. This occurrence is reported in a few papers (Green & Ennis-King 2012 and Hassanzadeh et. al. 2009).

6.9 Injection Designs

Most of the injection designs we test show the greatest potential occurs for perforations starting at layer 56. This is in terms of residual trapping, dissolution trapping and injectivity. In order to produce less cumulative CO\textsubscript{2} for our vertical injection and production well scenario, it is best to start the perforations at layer 66. In addition, it is best to choose the longest perforation as economically possible to inject the highest amount of supercritical CO\textsubscript{2}. Horizontal wells and SWAG show the least injectivity because layers in the reservoir have very low permeability. These cause the BHP of such wells to increase rapidly, reaching the maximum BHP in a shorter period of time. For the SWAG case, these low permeability layers minimise the contact between the downward flowing brine and the upward rising CO\textsubscript{2} plume. As a result, we inject less cumulative CO\textsubscript{2}. In addition, further study of injection designs with water production wells could result in no production of CO\textsubscript{2} at all. We observe that a WAG cycle ratio of 1:1 shows the best overall trapping benefit of 92\% (which means only 8\% mobile CO\textsubscript{2}). Although we maximise trapping benefit, this is compromised by a lower injectivity.

6.10 Well On-line Sequence

Finally, we test different sequences in which wells are brought online. The well sequence does not significantly affect the cumulative CO\textsubscript{2} injected, or residually trapped CO\textsubscript{2} or dissolved CO\textsubscript{2}. Online sequence 1 has the highest injectivity (0.5 Mt
better than the worst) while online sequence 3 shows the highest overall percentage for trapping (roughly 0.6% better than the worst).

6.11 Economic & Trapping Benefits

Table 6-1 summarises the conclusion we make from the analyses above.

Vertical wells -

a) are the most economically attractive
b) show intermediate overall trapping benefit

WAG wells -

a) are the least economically attractive
b) show the highest overall trapping benefit and especially early in the injection period.

Table 6-1: Qualitative comparison of economic and trapping benefits for different cases

<table>
<thead>
<tr>
<th>Injection Scheme</th>
<th>Economic Benefit</th>
<th>Trapping Benefit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Vertical Wells</td>
<td>High</td>
<td>Med</td>
</tr>
<tr>
<td>Horizontal Wells</td>
<td>Med</td>
<td>Low</td>
</tr>
<tr>
<td>Water Production</td>
<td>Med</td>
<td>Med</td>
</tr>
<tr>
<td>Water Alternating Gas</td>
<td>Low</td>
<td>High</td>
</tr>
</tbody>
</table>
7. References

8. Appendix A: Model modifications

Table 8-1: Summary of important parameters for our base case

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Grid number</td>
<td>$89 \times 74 \times 187 = 1,231,582$ grids</td>
</tr>
<tr>
<td>Fault status</td>
<td>Completely closed</td>
</tr>
<tr>
<td>Salinity</td>
<td>48,000 ppm</td>
</tr>
<tr>
<td>Temperature gradient</td>
<td>Same as Schlumberger (2013)</td>
</tr>
<tr>
<td>Wells used</td>
<td>II5N3, II6N3, II7N3, II8N3, II10N3, II11N3, II12N3, II16N3 and II17N3</td>
</tr>
<tr>
<td>Well positions</td>
<td>Same as Schlumberger (2013)</td>
</tr>
<tr>
<td>Perforation length</td>
<td>Same as Schlumberger (2013)</td>
</tr>
</tbody>
</table>

Figure 8-1: Relative permeability curves used (Evans et. al 2012)
9. Appendix B: Fault sensitivity

Figure 9-1: CO₂ mass rate vs. Time for closed faults (blue), semi-open faults (red) and open faults (green)

Figure 9-2: BHP vs. Time of well 10 for closed faults (blue), semi-open faults (red) and open faults (green)
Figure 9-3: \( \text{CO}_2 \) mass rate vs. Time of well 10 for closed faults (blue), semi-open faults (red) and open faults (green)

Figure 9-4: Residually trapped \( \text{CO}_2 \) vs. Time for closed faults (blue), semi-open faults (red) and open faults (green)
Figure 9-5: Dissolved CO₂ vs. Time for closed faults (blue), semi-open faults (red) and open faults (green)

Figure 9-6: Mobile CO₂ vs. Time for closed faults (blue), semi-open faults (red) and open faults (green)
10. Appendix C: Barrier between Wonnerup and Yalgorup Formations

Figure 10-1: CO$_2$ mass rate vs. Time of no barrier (blue) and barrier case (green)

Figure 10-2: BHP vs. Time of well 10 for no barrier (blue) and barrier case (green)
Figure 10-3: CO₂ mass rate vs. Time of well 10 for no barrier (blue) and barrier case (green)

Figure 10-4: Residually trapped CO₂ vs. Time for no barrier (blue) and barrier case (green)
Figure 10-5: Dissolved CO₂ vs. Time for no barrier (blue) and barrier case (green)

Figure 10-6: Mobile CO₂ vs. Time for no barrier (blue) and barrier case (green)
11. Appendix D: High permeability streaks

Figure 11-1: Plume spreading throughout layer $z = 85$ for Base Case, after 100 years of observation

Figure 11-2: Plume spreading throughout layer $z = 85$ for 10x permeability streak, after 100 years of observation
Figure 11-3: Plume spreading throughout layer $z = 85$ for 100x permeability streak, after 100 years of observation.

Figure 11-4: CO$_2$ mass rate vs. Time for Base Case (blue), 10x permeability streak (green) and 100x permeability streak (yellow).
Figure 11-5: Residually trapped CO$_2$ vs. Time for Base Case (blue), 10x permeability streak (green) and 100x permeability streak (yellow)

Figure 11-6: Dissolved CO$_2$ vs. Time for Base Case (blue), 10x permeability streak (green) and 100x permeability streak (yellow)
Figure 11-7: Mobile CO$_2$ vs. Time for Base Case (blue), 10x permeability streak (green) and 100x permeability streak (yellow)
12. Appendix E: Salting-out

Figure 12-1: Dissolved CO$_2$ vs. Time (48,000 ppm) for no salting-out (blue) and salting-out (red)

Figure 12-2: Dissolved CO$_2$ vs. Time (80,000 ppm) for no salting-out (blue) and salting-out (red)
13. Appendix F: Absolute permeability

Figure 13-1: Areal view of the grid blocks saturated with CO$_2$. It is clear that the Abs. Perm X2 case (right) achieves a higher surface area at the top of the plume.

Figure 13-2: CO$_2$ mass rate vs. Time for Base Case (blue) and Abs. Perm X2 case (red)
Figure 13-3: BHP of well 10 vs. Time for Base Case (blue) and Abs. Perm X2 case (red)

Figure 13-4: Residually trapped CO\textsubscript{2} vs. Time for Base Case (blue) and Abs. Perm X2 case (red)
Figure 13-5: Dissolved CO\textsubscript{2} vs. Time for Base Case (blue) and Abs. Perm X2 case (red)

Figure 13-6: Mobile CO\textsubscript{2} vs. Time for Base Case (blue) and Abs. Perm X2 case (red)
14. Appendix G: Model cropping

Figure 14-1: CO\textsubscript{2} mass rate vs. Time for Schlumberger model (blue) and cropped model (red)
Figure 14-2: Residually trapped CO$_2$ vs. Time for Schlumberger model (blue) and cropped model (red)

Figure 14-3: Dissolved CO$_2$ vs. Time for Schlumberger model (blue) and cropped model (red)
Figure 14-4: Mobile CO$_2$ vs. Time for Schlumberger model (blue) and cropped model (red)
Figure 14-5: Simulation computational time vs. years for Schlumberger model (blue) and cropped model (red)
15. Appendix H: Capillary pressure analysis

Figure 15-1: CO$_2$ mass rate vs. Time for Base Case (blue), Brooks-Corey / Van Genuchten (red) and J-Leverett model (green)
Figure 15-2: Residually trapped CO₂ vs. Time for Base Case (blue), Brooks-Corey / Van Genuchten (red) and J-Leverett model (green)

Figure 15-3: Dissolved CO₂ vs. Time for Base Case (blue), Brooks-Corey / Van Genuchten (red) and J-Leverett model (green)
Figure 15-4: Mobile CO₂ vs. Time for Base Case (blue), Brooks-Corey / Van Genuchten (red) and J-Leverett model (green)
16. Appendix I: Vertical Well Placement

Figure 16-1: Well positions of VWP scenarios Base and 1 - 5
Figure 16-2: CO$_2$ mass rate vs. Time for Base VWP (blue) and VWP 1 (red)

Figure 16-3: Residually trapped CO$_2$ vs. Time for Base VWP (blue) and VWP 1 (red)
Figure 16-4: Dissolved CO$_2$ vs. Time for Base VWP (blue) and VWP 1 (red)

Figure 16-5: Mobile CO$_2$ vs. Time for Base VWP (blue) and VWP 1 (red)
Figure 16-6: CO$_2$ mass rate vs. Time for Base VWP (blue) and VWP 2 (red)

Figure 16-7: Residually trapped CO$_2$ vs. Time for Base VWP (blue) and VWP 2 (red)
Figure 16-8: Dissolved CO₂ vs. Time for Base VWP (blue) and VWP 2 (red)

Figure 16-9: Mobile CO₂ vs. Time for Base VWP (blue) and VWP 2 (red)
Figure 16-10: CO₂ mass rate vs. Time for Base VWP (blue) and VWP 3 (red)

Figure 16-11: Residually trapped CO₂ vs. Time for Base VWP (blue) and VWP 3 (red)
Figure 16-12: Dissolved CO$_2$ vs. Time for Base VWP (blue) and VWP 3 (red)

Figure 16-13: Mobile CO$_2$ vs. Time for Base VWP (blue) and VWP 3 (red)
Figure 16-14: CO$_2$ mass rate vs. Time for Base VWP (blue) and VWP 4 (red)

Figure 16-15: Residually trapped CO$_2$ vs. Time for Base VWP (blue) and VWP 4 (red)
Figure 16-16: Dissolved CO$_2$ vs. Time for Base VWP (blue) and VWP 4 (red)

Figure 16-17: Mobile CO$_2$ vs. Time for Base VWP (blue) and VWP 4 (red)
Figure 16-18: CO$_2$ mass rate vs. Time for Base VWP (blue) and VWP 5 (red)

Figure 16-19: Residually trapped CO$_2$ vs. Time for Base VWP (blue) and VWP 5 (red)
Figure 16-20: Dissolved CO$_2$ vs. Time for Base VWP (blue) and VWP 5 (red)

Figure 16-21: Mobile CO$_2$ vs. Time for Base VWP (blue) and VWP 5 (red)
17. Appendix J: Grid Refinement Sensitivity Analysis

Figure 17-1: CO$_2$ mass rate vs. Time for Base Case (blue) and 2x2x1 refinement (red)

Figure 17-2: CO$_2$ mass rate vs. Time of Well 10 for Base Case (blue) and 2x2x1 refinement (red)
Figure 17-3: BHP vs. Time of Well 10 for Base Case (blue) and 2x2x1 refinement (red)

Figure 17-4: Residually trapped CO$_2$ vs. Time for Base Case (blue) and 2x2x1 refinement (red)
Figure 17-5: Dissolved CO$_2$ vs. Time for Base Case (blue) and 2x2x1 refinement (red)

Figure 17-6: Mobile CO$_2$ vs. Time for Base Case (blue) and 2x2x1 refinement (red)
Figure 17-7: CO$_2$ mass rate vs. Time for Base Case (blue) and 3x3x1 refinement (red)

Figure 17-8: CO$_2$ mass rate vs. Time of well 10 for Base Case (blue) and 3x3x1 refinement (red)
Figure 17-9: BHP vs. Time of Well 10 for Base Case (blue) and 3x3x1 refinement (red)

Figure 17-10: Residually trapped CO₂ vs. Time for Base Case (blue) and 3x3x1 refinement (red)
Figure 17-11: Dissolved CO$_2$ vs. Time for Base Case (blue) and 3x3x1 refinement (red)

Figure 17-12: Mobile CO$_2$ vs. Time for Base Case (blue) and 3x3x1 refinement (red)
Figure 17-13: CO₂ mass rate vs. Time for Base Case (blue) and 4x4x1 refinement (red)

Figure 17-14: CO₂ mass rate vs. Time of well 10 for Base Case (blue) and 4x4x1 refinement (red)
Figure 17-15: BHP vs. Time of well 10 for Base Case (blue) and 4x4x1 refinement (red)

Figure 17-16: Residually trapped CO$_2$ vs. Time for Base Case (blue) and 4x4x1 refinement (red)
Figure 17-17: Dissolved CO$_2$ vs. Time for Base Case (blue) and 4x4x1 refinement (red)

Figure 17-18: Mobile CO$_2$ vs. Time for Base Case (blue) and 4x4x1 refinement (red)
Figure 17-19: CO₂ mass rate vs. Time for Base Case (blue) and 5x5x1 refinement (red)

Figure 17-20: CO₂ mass rate vs. Time of well 10 for Base Case (blue) and 5x5x1 refinement (red)
Figure 17-21: BHP vs. Time of well 10 for Base Case (blue) and 5x5x1 refinement (red)

Figure 17-22: Residually trapped CO₂ vs. Time for Base Case (blue) and 5x5x1 refinement (red)
Figure 17-23: Dissolved CO\textsubscript{2} vs. Time for Base Case (blue) and 5x5x1 refinement (red)

Figure 17-24: Mobile CO\textsubscript{2} vs. Time for Base Case (blue) and 5x5x1 refinement (red)
Figure 17-25: CO\textsubscript{2} mass rate vs. Time for Base Case (blue) and 6x6x1 refinement (red)

Figure 17-26: CO\textsubscript{2} mass rate vs. Time of well 10 for Base Case (blue) and 6x6x1 refinement (red)
Figure 17-27: BHP vs. Time of well 10 for Base Case (blue) and 6x6x1 refinement (red)

Figure 17-28: Residually trapped CO₂ vs. Time for Base Case (blue) and 6x6x1 refinement (red)
Figure 17-29: Dissolved CO$_2$ vs. Time for Base Case (blue) and 6x6x1 refinement (red)

Figure 17-30: Mobile CO$_2$ vs. Time for Base Case (blue) and 6x6x1 refinement (red)
Figure 17-31: CO\textsubscript{2} mass rate vs. Time for Base Case (blue), 1x1x2 refinement (red) and 1x1x3 refinement (green).

Figure 17-32: Residually trapped CO\textsubscript{2} vs. Time for Base Case (blue), 1x1x2 refinement (red) and 1x1x3 refinement (green).
Figure 17-33: Dissolved CO₂ vs. Time for Base Case (blue), 1x1x2 refinement (red) and 1x1x3 refinement (green)

Figure 17-34: Mobile CO₂ vs. Time for Base Case (blue), 1x1x2 refinement (red) and 1x1x3 refinement (green)
18. Appendix K: Grid Refinement for All Scenarios

Figure 18-1: CO$_2$ mass rate vs. Time for Base VWP (red) and Refined Base VWP (blue)

Figure 18-2: Dissolved CO$_2$ vs. Time for Base VWP (red) and Refined Base VWP (blue)
Refined model simulation time is about 2.5 times slower than the unrefined model.
Figure 18-5: Dissolved CO$_2$ vs. Time for VWP 1 (red) and Refined VWP 1 (blue)

Figure 18-6: Simulation Time vs. Years for VWP 1 (red) and Refined VWP 1 (blue)

Refined model simulation time is about 2.3 times slower than the unrefined model.
Figure 18-7: CO$_2$ mass rate vs. Time for VWP 2 (red) and Refined VWP 2 (blue)

Figure 18-8: Dissolved CO$_2$ vs. Time for VWP 2 (red) and Refined VWP 2 (blue)
Refined model simulation time is about 2 times slower than the unrefined model.

Figure 18-9: Simulation Time vs. Years for VWP 2 (red) and Refined VWP 2 (blue)

Figure 18-10: CO₂ mass rate vs. Time for VWP 3 (red) and Refined VWP 3 (blue)
Figure 18-11: Dissolved CO$_2$ vs. Time for VWP 3 (red) and Refined VWP 3 (blue)

Figure 18-12: Simulation Time vs. Years for VWP 3 (red) and Refined VWP 3 (blue)
Figure 18-13: CO$_2$ mass rate vs. Time for VWP 4 (red) and Refined VWP 4 (blue)

Figure 18-14: Dissolved CO$_2$ vs. Time for VWP 4 (red) and Refined VWP 4 (blue)
Refined model simulation time is about 2.3 times slower than the unrefined model.

Figure 18-15: Simulation Time vs. Years for VWP 4 (red) and Refined VWP 4 (blue)

Figure 18-16: CO₂ mass rate vs. Time for VWP 5 (red) and Refined VWP 5 (blue)
Figure 18-17: Dissolved CO$_2$ vs. Time for VWP 5 (red) and Refined VWP 5 (blue)

Figure 18-18: Simulation Time vs. Years for VWP 5 (red) and Refined VWP 5 (blue)

Refined model simulation time is about 2.6 times slower than the unrefined model.
19. Appendix L: Vertical Well Optimisation

Figure 19-1: CO$_2$ mass rate vs. Time for perforations starting at layer 51 (blue), perforations starting at layer 56 (red) and perforations starting at layer 66 (green)

Figure 19-2: Residually trapped CO$_2$ vs. Time of Yalgorup Formation, for perforations starting at layer 51 (blue), perforations starting at layer 56 (red) and perforations starting at layer 66 (green)
Figure 19-3: Residually trapped CO$_2$ vs. Time of Wonnerup Formation, for perforations starting at layer 51 (blue), perforations starting at layer 56 (red) and perforations starting at layer 66 (green).

Figure 19-4: Dissolved CO$_2$ vs. Time for Yalgorup Formation, for perforations starting at layer 51 (blue), perforations starting at layer 56 (red) and perforations starting at layer 66 (green).
Figure 19-5: Dissolved CO\textsubscript{2} vs. Time for Wonnerup Formation, for perforations starting at layer 51 (blue), perforations starting at layer 56 (red) and perforations starting at layer 66 (green).

Figure 19-6: Mobile CO\textsubscript{2} vs. Time for Yalgorup Formation, for perforations starting at layer 51 (blue), perforations starting at layer 56 (red) and perforations starting at layer 66 (green).
Figure 19-7: Mobile CO$_2$ vs. Time for Wonnerup Formation, for perforations starting at layer 51 (blue), perforations starting at layer 56 (red) and perforations starting at layer 66 (green).

Figure 19-8: CO$_2$ mass rate vs. Time for perforation length of 350 m (blue), 500 m (red) and 650 m (green).
Figure 19-9: Residually trapped CO₂ vs. Time for Yalgorup Formation, for perforation length of 350 m (blue), 500 m (red) and 650 m (green).

Figure 19-10: Residually trapped CO₂ vs. Time for Wonnerup Formation, for perforation length of 350 m (blue), 500 m (red) and 650 m (green).
Figure 19-11: Dissolved CO$_2$ vs. Time for Yalgorup Formation, for perforation length of 350 m (blue), 500 m (red) and 650 m (green).

Figure 19-12: Dissolved CO$_2$ vs. Time for Wonnerup Formation, for perforation length of 350 m (blue), 500 m (red) and 650 m (green).
Figure 19-13: Mobile CO₂ vs. Time for Yalgorup Formation, for perforation length of 350 m (blue), 500 m (red) and 650 m (green).

Figure 19-14: Mobile CO₂ vs. Time for Wonnerup Formation, for perforation length of 350 m (blue), 500 m (red) and 650 m (green).
20. Appendix M: Horizontal well optimisation

Figure 20-1: CO₂ mass rate vs. Time for injecting in layer 51 (blue), layer 56 (red) and layer 66 (green)

Figure 20-2: Residually trapped CO₂ vs. Time within the Yalgorup Formation, for injecting in layer 51 (blue), layer 56 (red) and layer 66 (green)
Figure 20-3: Residually trapped CO₂ vs. Time within the Wonnerup Formation, for injecting in layer 51 (blue), layer 56 (red) and layer 66 (green).

Figure 20-4: Dissolved CO₂ vs. Time within the Yalgorup Formation, for injecting in layer 51 (blue), layer 56 (red) and layer 66 (green).
Figure 20-5: Dissolved CO$_2$ vs. Time within the Wonnerup Formation, for injecting in layer 51 (blue), layer 56 (red) and layer 66 (green)

Figure 20-6: Mobile CO$_2$ vs. Time within the Yalgorup Formation, for injecting in layer 51 (blue), layer 56 (red) and layer 66 (green)
Figure 20-7: Mobile CO$_2$ vs. Time within the Wonnerup Formation, for injecting in layer 51 (blue), layer 56 (red) and layer 66 (green).

Figure 20-8: CO$_2$ mass rate vs. Time for horizontal perforation intervals 1,000 m (blue), 2,000 m (red) and 3,000 m (green).
Figure 20-9: Residually trapped CO$_2$ vs. Time, within the Yalgorup Formation, for horizontal perforation intervals 1,000 m (blue), 2,000 m (red) and 3,000 m (green).

Figure 20-10: Residually trapped CO$_2$ vs. Time, within the Wonnerup Formation, for horizontal perforation intervals 1,000 m (blue), 2,000 m (red) and 3,000 m (green).
Figure 20-11: Dissolved CO$_2$ vs. Time, within the Yalgorup Formation, for horizontal perforation intervals 1,000 m (blue), 2,000 m (red) and 3,000 m (green)

Figure 20-12: Dissolved CO$_2$ vs. Time, within the Wonnerup Formation, for horizontal perforation intervals 1,000 m (blue), 2,000 m (red) and 3,000 m (green)
Figure 20-13: Mobile CO$_2$ vs. Time, within the Yalgorup Formation, for horizontal perforation intervals 1,000 m (blue), 2,000 m (red) and 3,000 m (green).

Figure 20-14: Mobile CO$_2$ vs. Time, within the Wonnerup Formation, for horizontal perforation intervals 1,000 m (blue), 2,000 m (red) and 3,000 m (green).
21. Appendix N: Vertical injection and production wells

Figure 21-1: CO₂ mass rate vs. Time for perforations starting at all three layers (51, 56 & 66). CO₂ breakthrough mass rate vs. Time for perforations starting at layer 51 (blue), layer 56 (purple) and layer 66 (orange)

Figure 21-2: Net CO₂ mass rate vs. Time for perforations starting at layer 51 (red), layer 56 (blue) and layer 66 (green)
Figure 21-3: Cumulative CO₂ production rate vs. Time for perforations starting at layer 51 (red), layer 56 (blue) and layer 66 (green)

Figure 21-4: Residually trapped CO₂ vs. Time, within the Yalgorup Formation, for perforations starting at layer 51 (red), layer 56 (blue) and layer 66 (green)
Figure 21-5: Residually trapped CO\textsubscript{2} vs. Time, within the Wonnerup Formation, for perforations starting at layer 51 (red), layer 56 (blue) and layer 66 (green).

Figure 21-6: Dissolved CO\textsubscript{2} vs. Time, within the Yalgorup Formation, for perforations starting at layer 51 (red), layer 56 (blue) and layer 66 (green).
Figure 21-7: Dissolved CO₂ vs. Time, within the Wonnerup Formation, for perforations starting at layer 51 (red), layer 56 (blue) and layer 66 (green).

Figure 21-8: Mobile CO₂ vs. Time, within the Yalgorup Formation, for perforations starting at layer 51 (red), layer 56 (blue) and layer 66 (green).
Figure 21-9: Mobile CO$_2$ vs. Time, within the Wonnerup Formation, for perforations starting at layer 51 (red), layer 56 (blue) and layer 66 (green)

Figure 21-10: Total water production rate vs. Time for perforations starting at layer 51 (red), layer 56 (blue) and layer 66 (green)
Figure 21-11: Total water production rate vs. Time for perforations starting at layer 51 (red), layer 56 (blue) and layer 66 (green).

Figure 21-12: CO$_2$ mass rate vs. Time for perforations intervals 350 m (red), 500 m (green) & 650 m (blue). CO$_2$ breakthrough mass rate vs. Time for perforation intervals 500 & 650 m.
Figure 21-13: Net CO\textsubscript{2} injection rate vs. Time for perforations intervals 350 m (red), 500 m (green) & 650 m (blue)

Figure 21-14: Cumulative CO\textsubscript{2} produced vs. Time for perforations intervals 350 m (red), 500 m (green) & 650 m (blue)
Figure 21-15: Residually trapped CO$_2$ vs. Time, within the Yalgorup Formation, for perforations intervals 350 m (red), 500 m (green) & 650 m (blue).

Figure 21-16: Residually trapped CO$_2$ vs. Time, within the Wonnerup Formation, for perforations intervals 350 m (red), 500 m (green) & 650 m (blue).
Figure 21-17: Dissolved CO₂ vs. Time, within the Yalgorup Formation, for perforations intervals 350 m (red), 500 m (green) & 650 m (blue)

Figure 21-18: Dissolved CO₂ vs. Time, within the Wonnerup Formation, for perforations intervals 350 m (red), 500 m (green) & 650 m (blue)
Figure 21-19: Mobile CO$_2$ vs. Time, within the Yalgorup Formation, for perforations intervals 350 m (red), 500 m (green) & 650 m (blue)

Figure 21-20: Mobile CO$_2$ vs. Time, within the Wonnerup Formation, for perforations intervals 350 m (red), 500 m (green) & 650 m (blue)
Figure 21-21: Total water production rate vs. Time for perforations intervals 350 m (red), 500 m (green) & 650 m (blue)

Figure 21-22: Cumulative water production vs. Time for perforations intervals 350 m (red), 500 m (green) & 650 m (blue)
22. Appendix O: Water Alternate Gas (WAG)

Figure 22-1: CO₂ mass rate vs. Time for different perforation intervals 350 m (red), 500 m (blue) & 650 m (green). CO₂ mass breakthrough vs. Time for different perforation intervals 350 m (purple), 500 m (light blue) & 650 m (orange)

Figure 22-2: Net CO₂ mass rate vs. Time for different perforation intervals 350 m (red), 500 m (blue) and 650 m (green)
Figure 22-3: Cumulative CO$_2$ produced vs. Time for different perforation intervals 350 m (red), 500 m (blue) and 650 m (green)

Figure 22-4: Residually trapped CO$_2$ vs. Time, within the Yalgorup Formation, for different perforation intervals 350 m (red), 500 m (blue) and 650 m (green)
Figure 22-5: Residually trapped CO$_2$ vs. Time, within the Wonnerup Formation, for different perforation intervals 350 m (red), 500 m (blue) and 650 m (green).

Figure 22-6: Dissolved CO$_2$ vs. Time, within the Yalgorup Formation, for different perforation intervals 350 m (red), 500 m (blue) and 650 m (green).
Figure 22-7: Dissolved CO$_2$ vs. Time, within the Wonnerup Formation, for different perforation intervals 350 m (red), 500 m (blue) and 650 m (green)

Figure 22-8: Mobile CO$_2$ vs. Time, within the Yalgorup Formation, for different perforation intervals 350 m (red), 500 m (blue) and 650 m (green)
Figure 22-9: Mobile CO$_2$ vs. Time, within the Wonnerup Formation, for different perforation intervals 350 m (red), 500 m (blue) and 650 m (green)

Figure 22-10: Water production rate vs. Time for different perforation intervals 350 m (red), 500 m (blue) and 650 m (green)
Figure 22-11: Cumulative water production vs. Time for different perforation intervals 350 m (red), 500 m (blue) and 650 m (green)

Figure 22-12: Water injection rate vs. Time for different perforation intervals 350 m (red), 500 m (blue) and 650 m (green)
Figure 22-13: Cumulative water injection vs. Time for different perforation intervals 350 m (red), 500 m (blue) and 650 m (green).

Figure 22-14: CO$_2$ mass rate vs. Time for different WAG cycle ratios 1:1 (blue), 1:2 (red) & 2:1 (green). CO$_2$ mass breakthrough vs. Time for different WAG cycle ratios 1:1 (light blue), 1:2 (purple) & 2:1 (orange).
Figure 22-15: Net CO₂ mass rate vs. Time for different WAG cycle ratios 1:1 (blue), 1:2 (red) & 2:1 (green)

Figure 22-16: Cumulative CO₂ produced vs. Time for different WAG cycle ratios 1:1 (blue), 1:2 (red) & 2:1 (green)
Figure 22-17: Residually trapped CO₂ vs. Time, within the Yalgorup Formation, for different WAG cycle ratios 1:1 (blue), 1:2 (red) & 2:1 (green)

Figure 22-18: Residually trapped CO₂ vs. Time, within the Wonnerup Formation, for different WAG cycle ratios 1:1 (blue), 1:2 (red) & 2:1 (green)
Figure 22-19: Dissolved CO\textsubscript{2} vs. Time, within the Yalgorup Formation, for different WAG cycle ratios 1:1 (blue), 1:2 (red) & 2:1 (green)

Figure 22-20: Dissolved CO\textsubscript{2} vs. Time, within the Wonnerup Formation, for different WAG cycle ratios 1:1 (blue), 1:2 (red) & 2:1 (green)
Figure 22-21: Mobile CO$_2$ vs. Time, within the Yalgorup Formation, for different WAG cycle ratios 1:1 (blue), 1:2 (red) & 2:1 (green)

Figure 22-22: Mobile CO$_2$ vs. Time, within the Wonnerup Formation, for different WAG cycle ratios 1:1 (blue), 1:2 (red) & 2:1 (green)
Figure 22-23: Water production rate vs. Time for different WAG cycle ratios 1:1 (blue), 1:2 (red) & 2:1 (green)

Figure 22-24: Cumulative water produced vs. Time for different WAG cycle ratios 1:1 (blue), 1:2 (red) & 2:1 (green)
Figure 22-25: Water injection rate vs. Time for different WAG cycle ratios 1:1 (blue), 1:2 (red) & 2:1 (green)

Figure 22-26: Cumulative water injection vs. Time for different WAG cycle ratios 1:1 (blue), 1:2 (red) & 2:1 (green)
23. Appendix P: Simultaneous Water Alternate Gas (SWG)

Figure 23-1: CO₂ mass rate vs. Time for different horizontal perforation intervals 600 m (red), 1,200 m (blue) & 1,800 m (green). CO₂ mass breakthrough vs. Time for different horizontal perforation intervals 600 m (purple), 1,200 m (light blue) & 1,800 m (orange)

Figure 23-2: Net CO₂ mass rate vs. Time for different horizontal perforation intervals 600 m (red), 1,200 m (blue) & 1,800 m (green)
Figure 23-3: Cumulative CO$_2$ production vs. Time for different horizontal perforation intervals 600 m (red), 1,200 m (blue) & 1,800 m (green)

Figure 23-4: Residually trapped CO$_2$ vs. Time, in the Yalgorup Formation, for different horizontal perforation intervals 600 m (red), 1,200 m (blue) & 1,800 m (green)
Figure 23-5: Residually trapped CO$_2$ vs. Time, in the Wonnerup Formation, for different horizontal perforation intervals 600 m (red), 1,200 m (blue) & 1,800 m (green).

Figure 23-6: Dissolved CO$_2$ vs. Time, in the Yalgorup Formation, for different horizontal perforation intervals 600 m (red), 1,200 m (blue) & 1,800 m (green).
Figure 23-7: Dissolved CO$_2$ vs. Time, in the Wonnerup Formation, for different horizontal perforation intervals 600 m (red), 1,200 m (blue) & 1,800 m (green).

Figure 23-8: Mobile CO$_2$ vs. Time, in the Yalgorup Formation, for different horizontal perforation intervals 600 m (red), 1,200 m (blue) & 1,800 m (green).
Figure 23-9: Mobile CO$_2$ vs. Time, in the Wonnerup Formation, for different horizontal perforation intervals 600 m (red), 1,200 m (blue) & 1,800 m (green)

Figure 23-10: Water injection rate vs. Time for different horizontal perforation intervals 600 m (red), 1,200 m (blue) & 1,800 m (green)
Figure 23-11: Cumulative water injection vs. Time for different horizontal perforation intervals 600 m (red), 1,200 m (blue) & 1,800 m (green)

Figure 23-12: Water production rate vs. Time for different horizontal perforation intervals 600 m (red), 1,200 m (blue) & 1,800 m (green)
Figure 23-13: Cumulative water production vs. Time for different horizontal perforation intervals 600 m (red), 1,200 m (blue) & 1,800 m (green)

Figure 23-14: CO₂ mass rate vs. Time for different distances between injectors 150 m (green) & 300 m (blue). CO₂ mass breakthrough vs. Time for different distances between injectors 150 m (orange) & 300 m (light blue)
Figure 23-15: Net CO$_2$ mass rate vs. Time for different distances between injectors 150 m (green) & 300 m (blue)

Figure 23-16: Cumulative CO$_2$ production vs. Time for different distances between injectors 150 m (green) & 300 m (blue)
Figure 23-17: Residually trapped CO$_2$ vs. Time, in the Yalgorup Formation, for different distances between injectors 150 m (green) & 300 m (blue)

Figure 23-18: Residually trapped CO$_2$ vs. Time, in the Wonnerup Formation, for different distances between injectors 150 m (green) & 300 m (blue)
Figure 23-19: Dissolved CO$_2$ vs. Time, in the Yalgorup Formation, for different distances between injectors 150 m (green) & 300 m (blue).

Figure 23-20: Residually trapped CO$_2$ vs. Time, in the Wonnerup Formation, for different distances between injectors 150 m (green) & 300 m (blue).
Figure 23-21: Mobile CO$_2$ vs. Time, in the Yalgorup Formation, for different distances between injectors 150 m (green) & 300 m (blue)

Figure 23-22: Mobile CO$_2$ vs. Time, in the Wonnerup Formation, for different distances between injectors 150 m (green) & 300 m (blue)
Figure 23-23: Water injection rate vs. Time for different distances between injectors 150 m (green) & 300 m (blue)

Figure 23-24: Cumulative water injection vs. Time for different distances between injectors 150 m (green) & 300 m (blue)
Figure 23-25: Water production rate vs. Time for different distances between injectors 150 m (green) & 300 m (blue)

Figure 23-26: Cumulative water production vs. Time for different distances between injectors 150 m (green) & 300 m (blue)
Figure 23-27: CO₂ mass rate vs. Time for different distances between CO₂ injector and brine producers 2,100 m (blue) & 2,700 m (green). CO₂ mass breakthrough vs. Time for different distances between CO₂ injector and brine producers 2,100 m (light blue) & 2,700 m (orange).

Figure 23-28: Net CO₂ mass rate vs. Time for different distances between CO₂ injector and brine producers 2,100 m (blue) & 2,700 m (green).
Figure 23-29: Cumulative CO$_2$ production vs. Time for different distances between CO$_2$ injector and brine producers 2,100 m (blue) & 2,700 m (green)

Figure 23-30: Residually trapped CO$_2$ vs. Time, in the Yalgorup Formation, for different distances between CO$_2$ injector and brine producers 2,100 m (blue) & 2,700 m (green)
Figure 23-31: Residually trapped CO₂ vs. Time, in the Wonnerup Formation, for different distances between CO₂ injector and brine producers 2,100 m (blue) & 2,700 m (green).

Figure 23-32: Dissolved CO₂ vs. Time, in the Yalgorup Formation, for different distances between CO₂ injector and brine producers 2,100 m (blue) & 2,700 m (green).
Figure 23-33: Dissolved CO$_2$ vs. Time, in the Wonnerup Formation, for different distances between CO$_2$ injector and brine producers 2,100 m (blue) & 2,700 m (green)

Figure 23-34: Dissolved CO$_2$ vs. Time, in the Yalgorup Formation, for different distances between CO$_2$ injector and brine producers 2,100 m (blue) & 2,700 m (green)
Figure 23-35: Mobile CO$_2$ vs. Time, in the Wonnerup Formation, for different distances between CO$_2$ injector and brine producers 2,100 m (blue) & 2,700 m (green).

Figure 23-36: Water injection rate vs. Time for different distances between CO$_2$ injector and brine producers 2,100 m (blue) & 2,700 m (green).
Figure 23-37: Cumulative water injection vs. Time for different distances between CO₂ injector and brine producers 2,100 m (blue) & 2,700 m (green)

Cumulative water injection (Msm³)

Time (yrs)

0 10 20 30 40

2,100 m

2,700 m

Figure 23-38: Water production rate vs. Time for different distances between CO₂ injector and brine producers 2,100 m (blue) & 2,700 m (green)

Total water production rate (sm³/day)

Time (yrs)

0 10 20 30 40

2,100 m

2,700 m
Figure 23-39: Cumulative water production vs. Time for different distances between CO₂ injector and brine producers 2,100 m (blue) & 2,700 m (green)
24. Appendix Q: Online well sequence

Figure 24-1: Mass rate of CO$_2$ vs. Time for different online sequences Base Case (blue), ONS 1 (red), ONS 2 (green), ONS 3 (light blue) & ONS 4 (purple)

Figure 24-2: Residually trapped CO$_2$ vs. Time for different online sequences Base Case (blue), ONS 1 (red), ONS 2 (green), ONS 3 (light blue) & ONS 4 (purple)
Figure 24-3: Dissolved CO$_2$ vs. Time for different online sequences Base Case (blue), ONS 1 (red), ONS 2 (green), ONS 3 (light blue) & ONS 4 (purple)

Figure 24-4: Mobile CO$_2$ vs. Time for different online sequences Base Case (blue), ONS 1 (red), ONS 2 (green), ONS 3 (light blue) & ONS 4 (purple)
25. Appendix R: SW-HUB Reservoir Simulation
Please refer to ‘SW HUB Reservoir Simulation’ folder provided.

26. Appendix S: SW-HUB Economic Analysis
Please refer to ‘SW HUB Economic Analysis’ MS Excel file provided.

27. Appendix T: Pipeline Cost Estimation
Please refer to ‘Pipeline Cost Estimation’ MS Excel file provided.