Programme Area: Carbon Capture and Storage

Project: DECC Storage Appraisal

Title: WP5 Report – Forties 5 Aquifer Storage Site Selection Study

Abstract:

The Forties 5 Open Aquifer unit was selected as one of the five CO2 storage targets that will be progressed to WP5. The sheer size of the unit means that it is not sensible to consider the development of the whole site in a single phase. The purpose of this supplementary workscope is to: 1. Identify through more detailed work an appropriate site to initiate CO2 injection within the Forties 5 unit such that the potential of Open Aquifer systems can be developed and matured. 2. To reconsider those previously eliminated large oil fields of the Central and Northern North Sea which have significant EOR potential as a fall back location, in the unlikely event that a suitable Forties 5 injection site cannot be identified.

Context:

This project, funded with up to £2.5m from the UK Department of Energy and Climate Change (DECC - now the Department of Business, Energy and Industrial Strategy), was led by Aberdeen-based consultancy Pale Blue Dot Energy supported by Axis Well Technology and Costain. The project appraised five selected CO2 storage sites towards readiness for Final Investment Decisions. The sites were selected from a short-list of 20 (drawn from a long-list of 579 potential sites), representing the tip of a very large strategic national CO2 storage resource potential (estimated as 78,000 million tonnes). The sites were selected based on their potential to mobilise commercial-scale carbon, capture and storage projects for the UK. Outline development plans and budgets were prepared, confirming no major technical hurdles to storing industrial scale CO2 offshore in the UK with sites able to service both mainland Europe and the UK. The project built on data from CO2 Stored - the UK's CO2 storage atlas - a database which was created from the ETI's UK Storage Appraisal Project. This is now publically available and being further developed by The Crown Estate and the British Geological Survey. Information on CO2Stored is available at www.co2stored.com.

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1.0 Executive Summary

The Forties 5 Open Aquifer unit was selected as one of the five CO_2 storage targets that will be progressed to WP5. The sheer size of the unit means that it is not sensible to consider the development of the whole site in a single phase. The purpose of this supplementary workscope is to:

1. Identify through more detailed work an appropriate site to initiate CO_2 injection within the Forties 5 unit such that the potential of Open Aquifer systems can be developed and matured.
2. To reconsider those previously eliminated large oil fields of the Central and Northern North Sea which have significant EOR potential as a fall back location, in the unlikely event that a suitable Forties 5 injection site cannot be identified.

The Forties Sand Member is an elongate (NW-SE) sand rich turbidite fan system of the Palaeocene Sele Formation, which is present across a large area of the Central North Sea, covering approximately 300km x 100km (at its widest). It is a prolific hydrocarbon reservoir with many producing fields such as Forties, Nelson, Montrose-Arbroath, Everest, Pierce, the Gannet cluster and Guillemot A.

Looking for an initial Forties 5 CO_2 injection site for further detailed analysis in such a large area presented several technical challenges. Due to its size, detailed modelling of the entire Forties Aquifer region is not practical. So, for the purposes of this study a relatively coarse gridded 3D model was built over the entire area and streamline reservoir simulation model was used to assess injectivity potential and CO_2 plume migration for each of five potential CO_2 injection sites. Workflows and methodologies were adapted to allow the study to be completed in three weeks.

For the Forties Aquifer screening, a four-step methodology was deployed based around standard subsurface workflows:

1. Define the aquifer storage region – this involved seismic and structural interpretation together with subsurface characterisation from well logs to build a model and understanding of the subsurface configuration including the important containment risks associated with each site.
2. Populate the model – This involved defining the key properties of the subsurface formations such as shale content, porosity and permeability in a geocellular model.
3. Dynamic model performance – In this case a streamline simulation model was used to evaluate the potential CO_2 injection performance and plume development.
4. Site Selection – this brought the results of the interpretation, modelling and containment review work together to build a logical and robust rationale for site selection. Here it included some further validation simulation runs using Eclipse 100.

The 3D seismic available is the full stack PGS mega-survey. The Top Forties was interpreted in time over the whole Forties 5 area and converted to depth using industry standard depth conversion techniques. Well correlation of the Top and Base of the Forties was carried out for a representative subset of wells. These well thicknesses were used to calculate a Base Forties. The Top and Base Forties depth surface were used to build the 3D grid for modelling.

Sand and shale facies were modelled to capture the reservoir heterogeneity and the baffling impact of the shale both vertically and laterally. The facies are modelled elongate NW – SE to honour the depositional direction. The facies modelling incorporates regional depositional trends generated from well data. Porosity and permeability are modelled from well data, also incorporating the regional depositional trends. There is a very strong depositional trend controlling the permeability with average values ranging from 700 mD in the north-west to less than 10mD in the south.

The dynamic modelling was carried out using streamline reservoir simulation as it is particularly efficient at solving large, geologically complex models. The model has 10 million grid cells. Five injection wells were located in the deepest, best quality areas within each of the five injection sites. Target mass rates were set at 1MT/year per well for an injection period of 50 years. The fracture pressure was set as the bottom hole pressure constraint. In an unconstrained case, 250MT of CO_2 could be injected into the injection site. All injection sites reached the fracture pressure limit at some point during the 50 years of injection resulting in a range of injected volumes from 33MT to 188MT. In the most southerly site (Site 2), not all of the five wells could inject at the target initial injection rate, due to the low permeability in this region. All four remaining sites are reasonable potential storage locations.

The top seal for the Forties sand is provided by the overlying mudstones of the Sele Formation, which provide the proven seal for hydrocarbon fields within the main area of the Forties fan. Containment along the eastern edge of the main fan is provided by the sands thinning or pinching out, stratigraphically trapped by the surrounding mudstones. Geological containment across the main area of the Forties fan where there are many hydrocarbon accumulations is generally seen as low risk. Despite the fact that sites in the northern and western parts of the system however (Sites 3,4 and 5) have good reservoir quality characteristics and achieved high injection inventories in the comparative testing, there are potential leak paths from the Forties sand fairway into secondary reservoirs that present a geological containment risk. These are illustrated later in a common risk segment map Figure 29.

The site with the best combination of low geological containment risk and injection / storage potential is Site 1. This located in the East of the Forties aquifer just south of the Everest gas field, a proven structural trap. Site 1 was selected because it has a good combination of substantial capacity and low containment risk and this combination probably offers the best opportunity for the first development of CO_2 storage within the Forties aquifer system. Sites 2, 3, 4 and 5 also represent good storage prospects provided that the containment risks are appropriately addressed in any future development plan.

Validation of the dynamic assessment of Site 1 was carried out using conventional simulation. A sector model was extracted from the full Forties aquifer model over Site 1 and the model was used to assess the migration of the CO_2 plume 1000 years after injection ceased. Injectivity was in agreement with the streamline simulation results. The CO_2 plume migrated towards the Everest field but did not reach the field after 1000 years. Further subsurface sensitivities will be carried out in the detailed modelling in WP5 but if the plume migrates further and faster than expected it will migrate to the Everest field where it will be structurally trapped.

Finally, given the “open” nature of this saline aquifer system and the challenge associated with defining boundaries around such systems for licensing, ETI requested that some further consideration also be given to the role that large depleted hydrocarbon fields might have in supporting a Central North Sea CCS build out programme. To this end those candidate fields in the Central and Northern North Sea that were eliminated because of their EOR potential in WP3 were briefly revisited in parallel with the Forties aquifer site screening work. This was to identify and provide a depleted hydrocarbon field back up site in the event that a suitable initial Forties open aquifer injection location could not be identified.

A brief review of 18 oil fields identified as likely EOR candidates was completed. This used recovery factor as a proxy to estimate the EOR potential, with lower recovery factors indicating that a larger proportion of the STOIIP will remain as an EOR target. Seven fields were identified as less promising EOR candidates and therefore perhaps more likely to be available for CO_2 storage. Of these two had been assessed and screened out during WP3 on the basis of their poor storage attributes. The remaining five sites were added to the Qualified Inventory and the TOPSIS ranking was repeated to compare their performance with the other storage units. From these five petroleum sites, the most promising as storage candidates were Fulmar and Forties (oil field) however none of the five petroleum sites appeared in the top twenty ranked sites. As a result, none of these sites performed well enough to merit a place in the Select Inventory and the decision was made not to progress the analysis any further, but retain the Britannia gas condensate field located in the north of the Forties 5 unit area as a potential reserve site for the Forties 5 unit. Britannia was a high performing site in the original WP3 ranking process only being substituted by Bruce because of Britannia's late COP.

2.0 Objective

The Forties 5 Aquifer was selected as one of the five CO_2 storage targets that will be progressed to WP5. The purpose of this Site Selection Study is to identify the area of the Forties 5 Aquifer which would represent the most promising site from which to begin CO_2 storage development in the Forties 5 Aquifer. The selected site would then be subject to further detailed analysis in WP5 culminating in an outline storage development plan for that location.

An additional objective of this supplementary piece of work is to address a view from the Project Stage Gate Review that some of the eliminated oil fields were actually potentially poor EOR candidates and therefore should be screened in the same way as the other storage units and identify any that should be included in the Select Inventory. There are two linked objectives:

1. Rank the EOR candidate oil fields eliminated during WP3, in accordance with the agreed screening methodology, according to their likely attractiveness as EOR developments. Subsequently to assess the storage site attributes of those oil fields deemed least likely to be developed as EOR projects.
2. Assess whether any of these units should be promoted to the Select Inventory in the event that a suitable storage location cannot be identified in the Forties 5 aquifer.

The Forties sand is an extensive open aquifer system, extending over 20,000km^2. Due to its size, detailed modelling of the entire Forties Aquifer region is not practical.

The site selection study involved building a 3D static and dynamic model, of a suitable scale, covering the entire Forties 5 open aquifer region. This allowed the injectivity, storage potential and containment characteristics to be assessed across the whole area so that the most promising site could be identified.

This work has resulted in the selection of a potential storage site within the Forties 5 aquifer which is considered to have the highest confidence of CO_2 containment together with robust injectivity and storage potential. The other sites tested remain viable storage targets in their own right.

Some Useful Definitions

Storage Site - means a defined volume area within a geological formation used for the geological storage of CO_2 and associated surface and injection facilities (EU CCS Directive);

Geological Formation - means a lithostratigraphical subdivision within which distinct rock layers can be found and mapped (EU CCS Directive);

Leakage - means any release of CO_2 from the storage complex (EU CCS Directive);

Storage Complex - means the storage site and surrounding geological domain which can have an effect on overall storage integrity and security; that is, secondary containment formations (EU CCS Directive);

Hydraulic Unit - means a hydraulically connected pore space where pressure communication can be measured by technical means and which is bordered by flow barriers, such as faults, salt domes, lithological boundaries, or by the wedging out or outcropping of the formation (EU CCS Directive);

Storage Unit – means a mappable subsurface body of reservoir rock that is at depths greater than 800 m below sea level, has similar geological characteristics and which has the potential to retain CO_2 (UKSAP)

3.0 Methodology

The workflow for the Forties site selection screening is similar in many respects to that which will be deployed for the detailed modelling for each storage site. The workflow is illustrated in Figure 1.

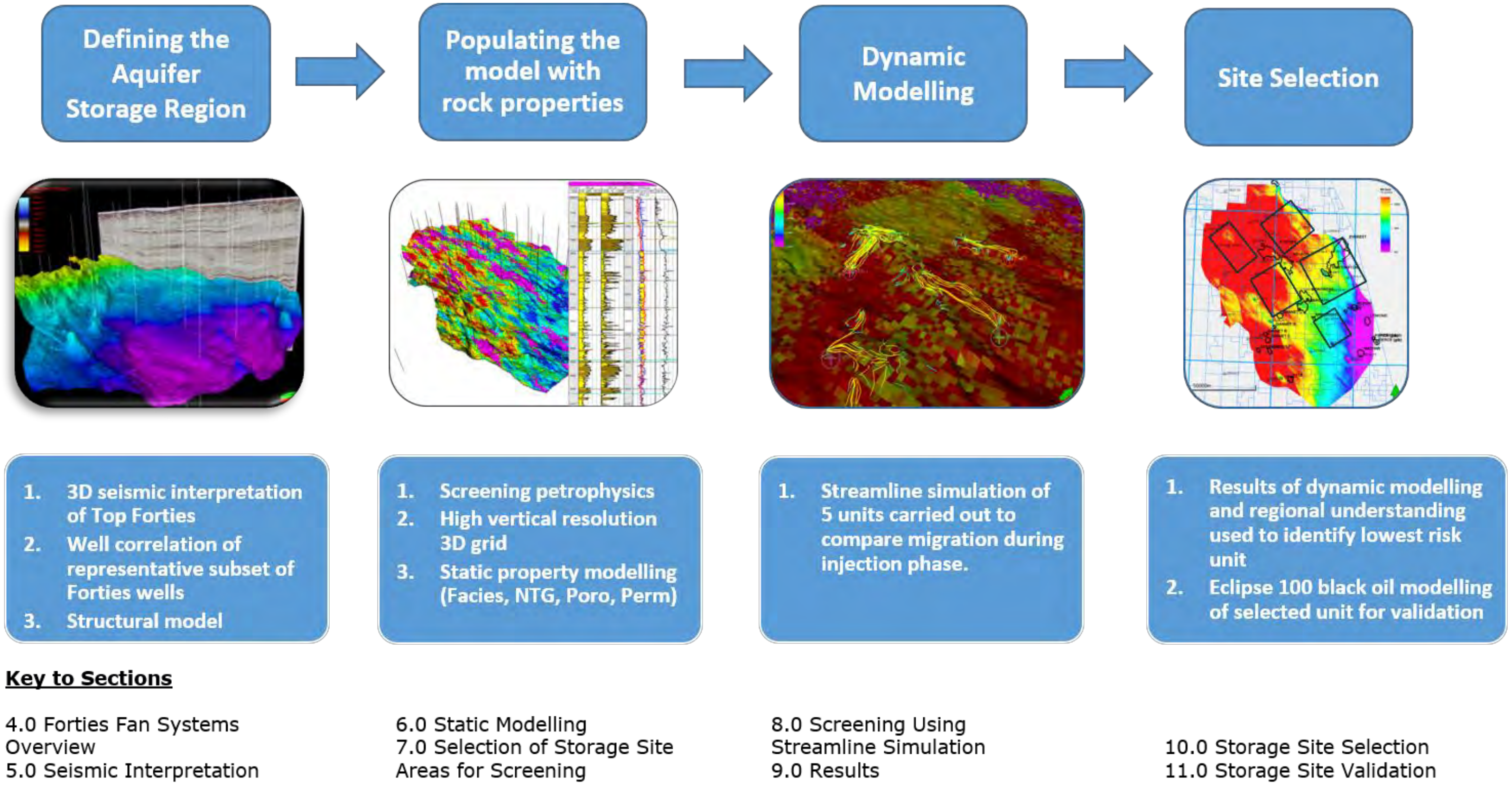

Figure 1 - Forties Screening Workflow and key document sections

Defining the Aquifer Storage Region

- As the Forties 5 region is such a large area which is likely to be the target of several independent or co-ordinated developments, this area cannot be considered to be a "Storage Complex" as defined in the CCS Directive. Storage complex definition is reserved for specific injection site. Here, the Top Forties was interpreted in time over the whole Forties 5 area and converted to depth using industry standard depth conversion techniques. Well correlation of the Top and Base of the Forties was carried out for a representative subset of wells. These well thicknesses were used to calculate a Base Forties. The Top and Base Forties depth surface were used to build the 3D grid for modelling.

Populating the Model with Rock Properties

- High level screening petrophysics was carried out on a subset of wells across the whole Forties 5 area. The results of this, and regional depositional trend information, were used to populate a very large 3D grid with rock properties for input to the dynamic modelling. These properties included a simple facies (rock type) model, net to gross, porosity and permeability.

Dynamic Modelling

- A 3D model was built for the entire Forties 5 area and streamline simulation, using FRONTSIM, was used to compare the injectivity and migration of CO_2 in 5 different injection sites. Streamline simulation can only be used during the injection phase and so the injection phase was extended to 50 years as a modelling convenience. A target rate of 1MT/year per well was injected for 50 years for the site assessment, equating to a potential mass volume of 250MT CO_2. This is not representative of the storage capacity at each site but is used as a target volume to assess and compare injectivity and CO_2 migration for each site.

Storage Site Selection

- The five selected Forties sites were assessed for confidence in geological containment, risk to injectivity and migration of the CO_2 plume. A comparison of the injection sites was made and the site with least risk was selected to progress to WP5 detailed modelling workflow.
- Validation of the extent of the CO_2 plume migration was carried out using conventional simulation, using E100. A sector model was extracted from the full Forties 5 area model, over the selected storage site area, allowing for a more manageable sized grid for dynamic modelling. This was used to predict the CO_2 migration over a 20 year injection period and the 1000 years after the injection phase ended.

A summary comparison of streamline and conventional simulation modelling is provided in Section 8.0.

4.0 Forties Fan System Overview

The Forties Sand Member is an elongate (NW-SE) sand rich turbidite fan system of the Palaeocene Sele Formation, which is present across a large area of the Central North Sea, covering approximately 300km x 100km (at its widest). It is a prolific hydrocarbon reservoir with many producing fields such as Forties, Nelson, Montrose-Arbroath, Pierce, the Gannet cluster and Guillemot A.

The main Forties fan is deposited from the northwest. There are clear depositional trends from the northwest (proximal – near to the source of the sediment input) to southeast (distal – furthest away from the source of sediment input) areas of the fan. The proximal areas are characterised by thicker, high quality channelized sands (>800 ft thick, net to gross 65%, porosity 23-26%, permeability 300 – 700 mD), whereas the distal downdip sands are thinner, more lobate or sheet like in nature with poorer rock properties (400ft thick, net to gross 50%, porosity 16-23%, permeability <10-80 mD) (Figure 2).

In addition to the main Forties fan there are smaller, overlapping, westerly derived lateral fans. These show similar proximal to distal trends in rock properties.

The top seal for the Forties sand is provided by the overlying mudstones of the Sele Formation, which provide the proven seal for hydrocarbon fields within the main Forties fan area. Containment along the eastern edge of the fan is provided by the sands thinning or pinching out, stratigraphically trapped by the surrounding mudstones. Geological containment across the main part of the Forties fan area where there are hydrocarbon accumulations is generally seen as low risk, however in the west and north, there are some potential leak paths from the Forties sand fairway into secondary reservoirs that present a geological containment risk (Figure 3):

- The updip continuation of the Forties sand fairway to the north and northwest.
- Thick sequences of shallower sands (Dornoch and Cromarty sands) observed in both well data and seismic, overlying the Forties sand towards the northwest.
- To the west the lateral fan systems provide potential leak paths through to thick sequences of shallower sands which include the Cromarty and Tay.

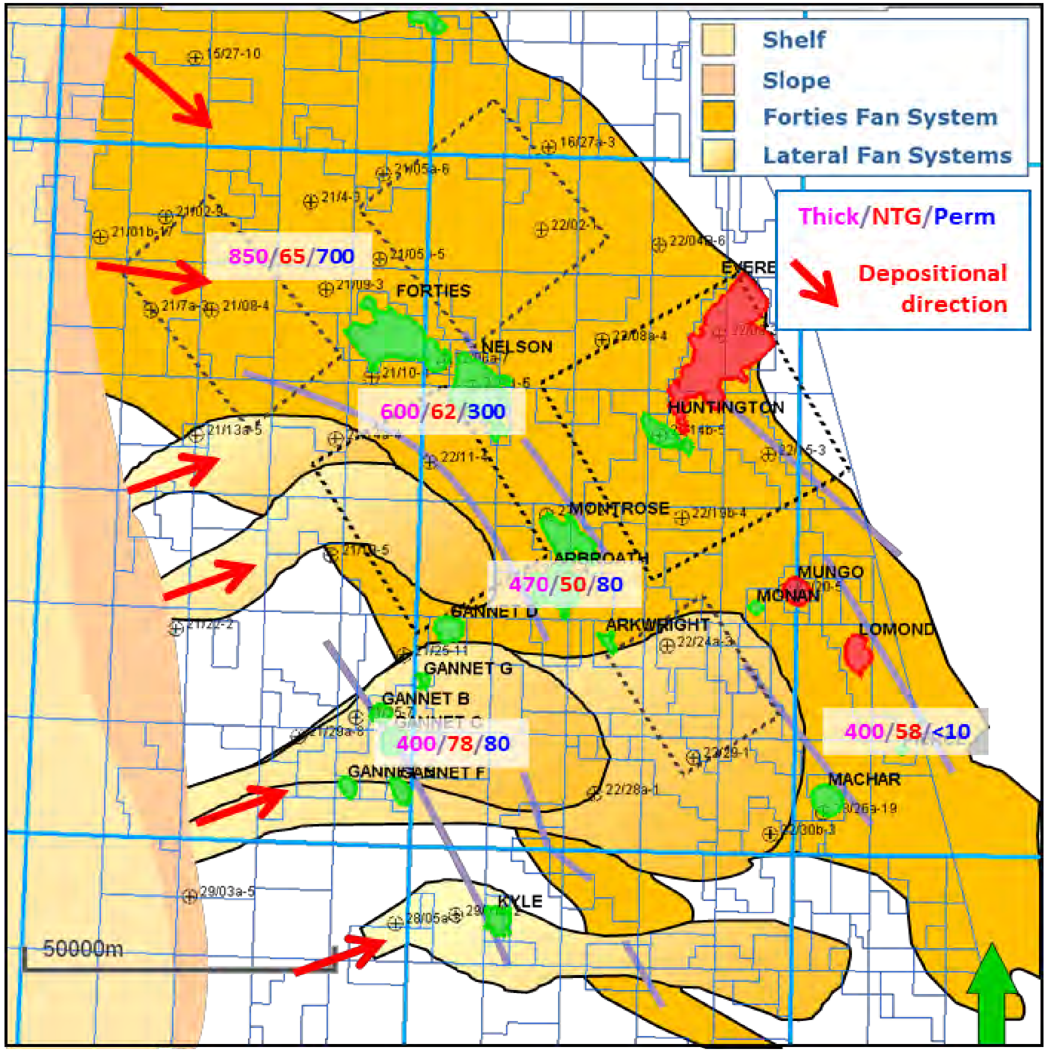

Figure 2 - Forties Sand Depositional Setting

Notes to Figure 2

This depositional setting is based upon work by (Hempton, et al., 2005). In Palaeocene times, sediment poured from the shallow water shelf area to the west and north into the deep basin as intermittent mass flow deposits or turbidites. These sediment input points are represented by the red arrows. Data from Forties Sand oil and gas fields (green and red areas) are shown as three numbers representing reservoir thickness in feet, the net to gross ratio as a % and the average permeability in millidarcies. This clearly shows how the reservoir quality declines from the proximal areas (red arrows) to distal limits of the fan system. The main Forties fan system which trends NW-SE is augmented by smaller fan systems which run WSW – ENE which bring sediment from the shelf area in the west.

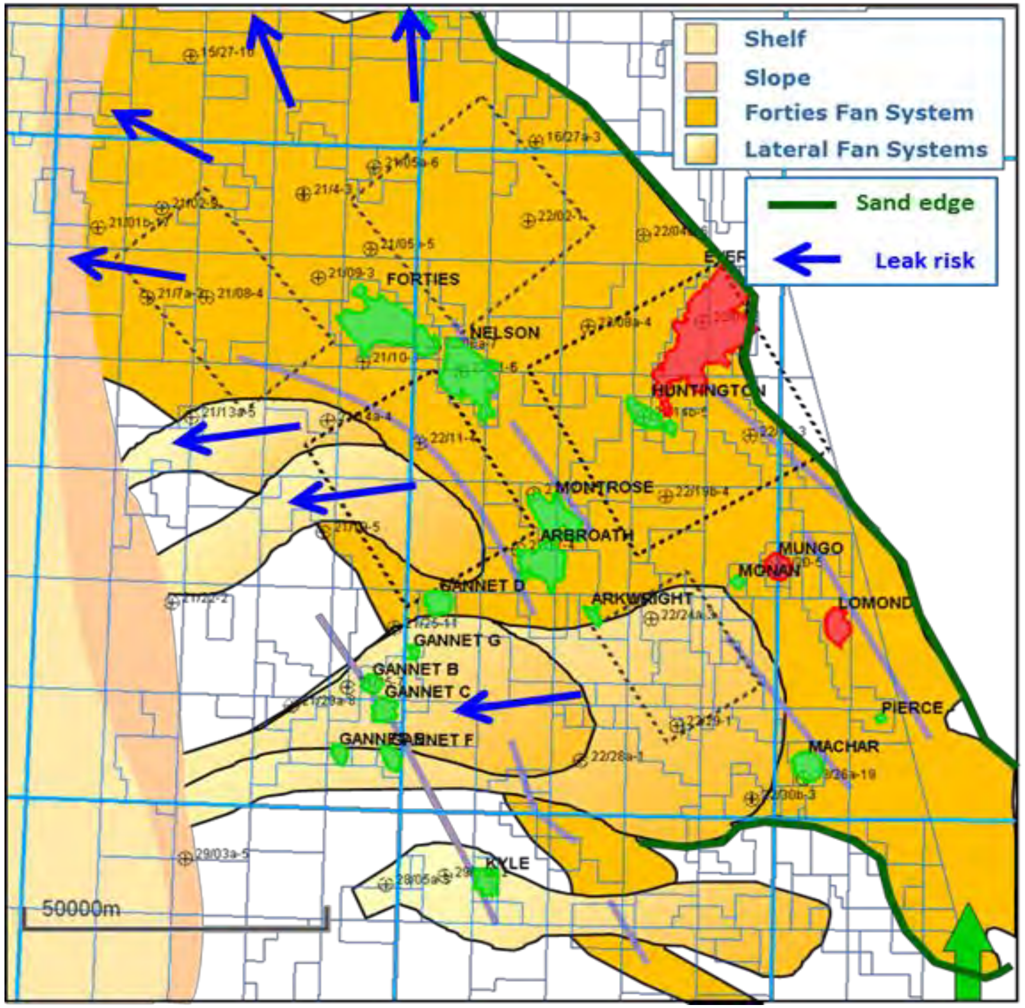

Figure 3 - Forties Containment Risks

Notes to Figure 3

The distribution of oil and gas fields within the Forties formation provide a good indication of where the overlying cap rock lithologies are suitable for retaining oil and gas. To the north and west of this area, the overlying formations become more sandy in nature and a "dry hole analysis" has indicated that hydrocarbon shows extend up into shallower formations indicating the potential for containment risk in these areas.

5.0 Seismic Interpretation

The extent of 3D seismic coverage of the Forties 5 Aquifer storage region is shown in Figure 5. The 3D seismic available is the full stack PGS mega-survey. The data was loaded into a Petrel geoscience workstation project. PGS state the polarity of the seismic volume to be SEG Reversed Polarity (North Sea Normal, decrease in AI is a positive number and plotted as a peak). In addition to the seismic reflection volume a coherency volume was generated for the Forties 5 area. Over the area of the Forties 5 saline aquifer, the data quality of the PGS mega-survey at Top Forties is generally good to very good, although the pick confidence decreases towards the north and west as the nature of the overlying interval changes. Of the five test sites selected, four are fully covered with 3D whilst Site 3 only has 75% coverage. Figure 4 is an autotracker confidence map of the Top Forties event and is a reasonable representation of the seismic data quality at the target horizon over the area. Note that the areas in the west and north are lower confidence than elsewhere as the Top Forties becomes more difficult to identify largely due to the changing nature of the overlying caprock interval. The white zones are areas where there is no 3D seismic available in the PGS mega-survey. These issues have the impact of increasing interpretation uncertainty locally in these areas although the regional trends are largely unaffected.

Over 2000 wells have been drilled within the Forties 5 area. Around 50 wells were selected to provide well to seismic ties (Figure 6). These wells were chosen as they have digital well logs and time-depth data available within CDA.

In addition to these, a synthetic seismogram was produced in Petrel for well 22/09-3 (Figure 7 and Figure 8). The following horizons were interpreted:

- Near Top Balder (varies between peak and a trough) - Decrease AI, amplitude peak.
- Top Sele - Decrease AI, amplitude peak.
- Top Forties Sandstone - Increase AI, amplitude trough.
- Base Tertiary - Increase AI, amplitude trough.
- Top Lower Cretaceous - Increase AI, amplitude trough.
- Base Cretaceous Unconformity - Decrease AI, amplitude peak.

After a manual interpretation of an initial seed grid, the Top Sele and Top Forties were auto tracked across the whole storage region (Figure 10). This was checked and additional seed points added until an acceptable auto-tracked interpretation was achieved. The coherency slice at Top Forties (Figure 11) shows that faulting is generally minor except towards the NW where larger throwing faults can be seen. The coherency data also shows that there are some splicing artefacts within the data, which result from the seismic survey merging process. This is an inevitable consequence of trying to preserve the best quality seismic information when multiple surveys of different vintages are merged together. This is generally not an issue of significance for interpretation, but the interpreter must be aware of it at all times when working with the data.

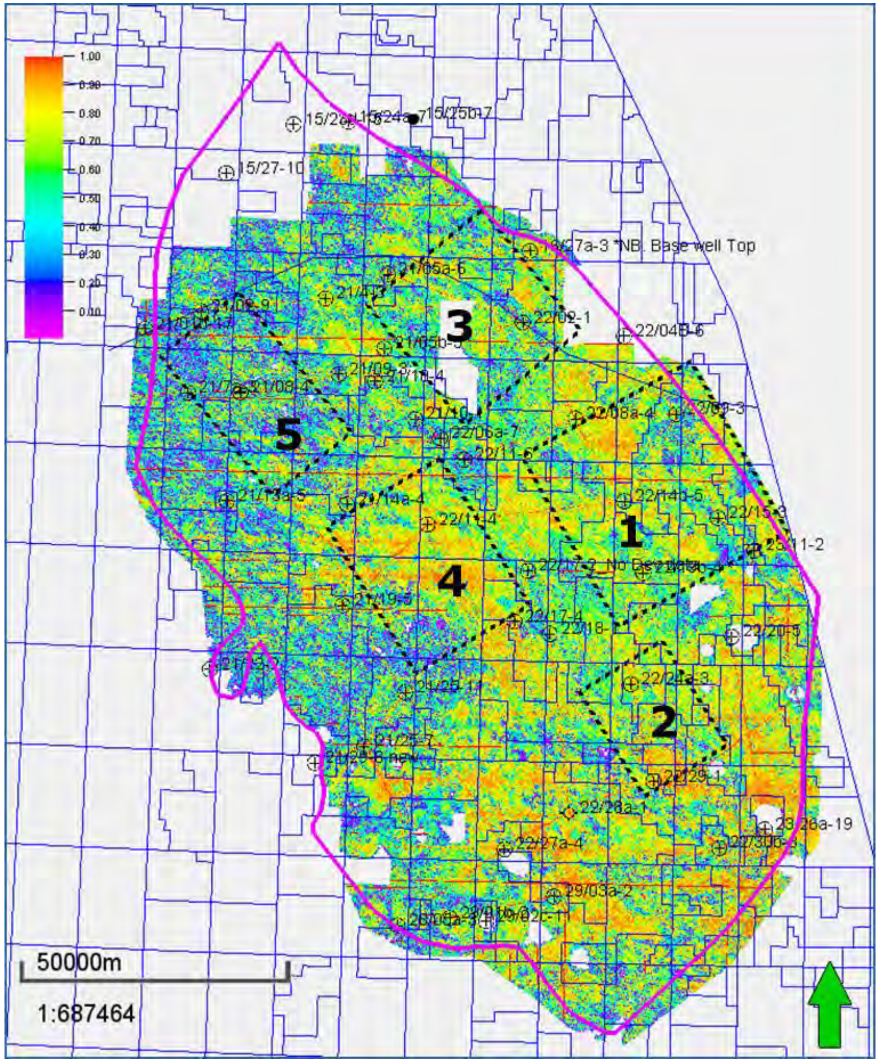

Figure 4 - Autotracker confidence map

Figure 15 also clearly shows the salt diapirs that are common in the southern part of the region.

An example South West to North East seismic line illustrating the picked events is shown in Figure 9.

Notes to Figure 4

This map shows the variation in seismic data quality at Top Forties level across the area of interest. Red, yellow and green denote higher quality with blue and purple denoting lower quality.

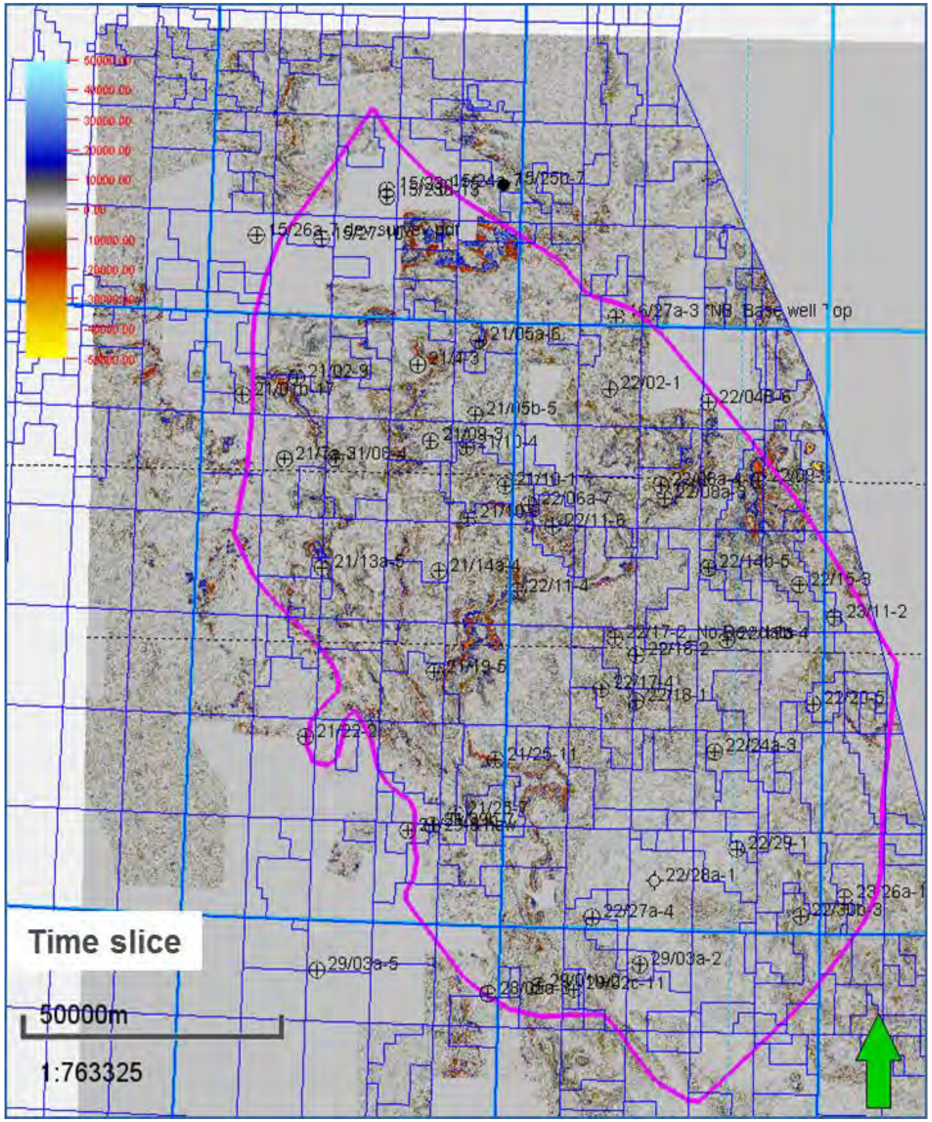

Figure 5 - 3D Seismic Data coverage (PGS Mega-Survey)

Notes to Figure 5

The PGS Mega- Survey is a amalgamation of many different 3D seismic surveys acquired by different operators at different times. This results in a "quilt" of surveys, which have extensive regional coverage, but occasionally there are gaps between surveys. These can be seen in this figure as blank areas. Whilst other 3D seismic data may be available which could infill these blank areas these are not available to this project.

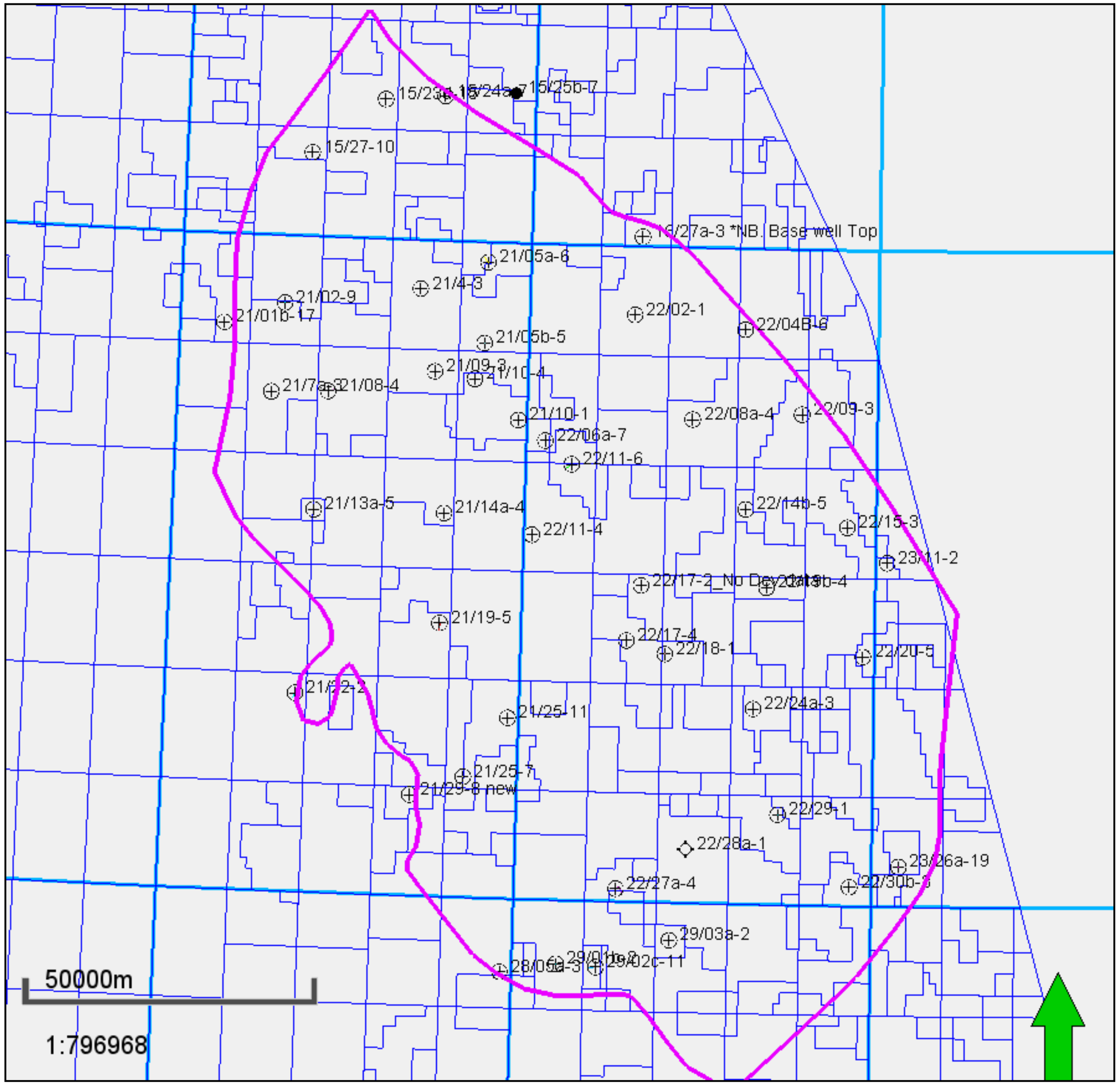

Figure 6 - Wells used in the seismic interpretation

Notes to Figure 6

Contrary to popular view, Saline aquifers often have lots of well data. With over 2000 wells drilled within the Forties 5 saline aquifer area, there is no shortage of well data. To conduct a rapid seismic interpretation, a subset of these containing appropriate log data were chosen to help to calibrate the seismic data to hard well data points. This figure illustrates the distribution of these calibration points.

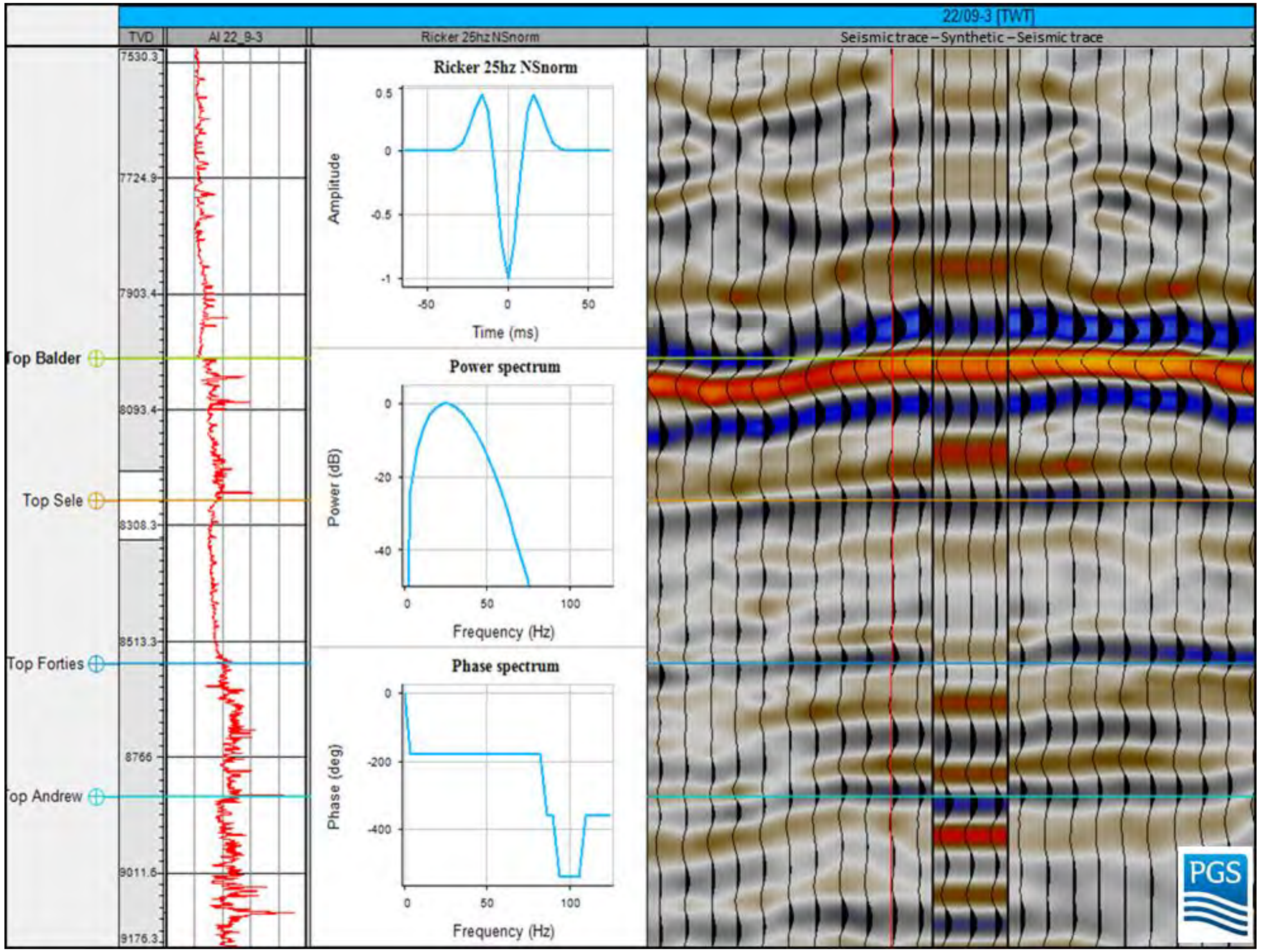

Figure 7 - Synthetic Seismogram 22/09-3 (Everest Field Well)

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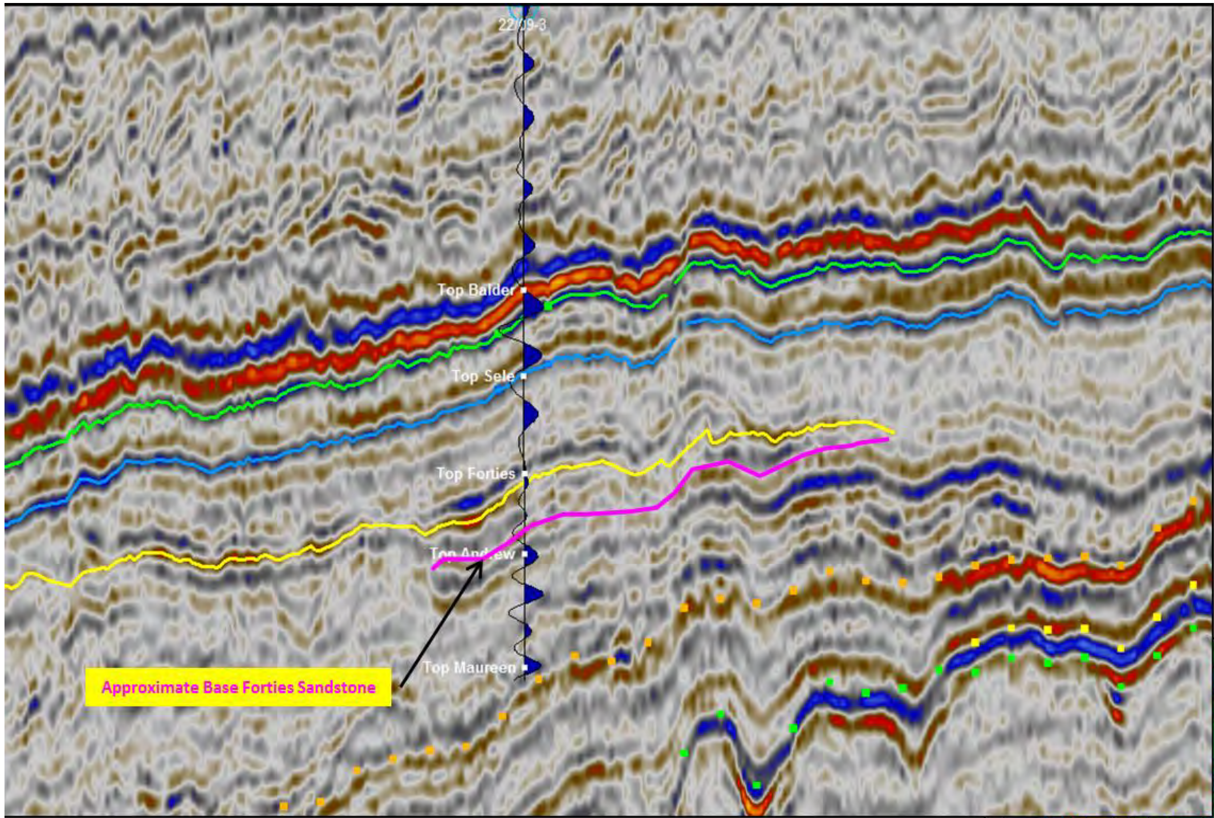
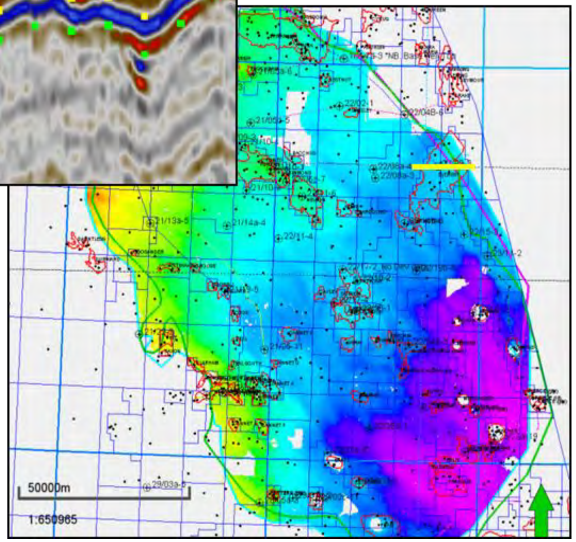
This is an example of a display called a synthetic seismogram for one of the calibration wells. The wireline log data curves on the left are used to build an acoustic model of the earth across which a simulated seismic pulse is passed (Ricker 25hz NSnorm). This is converted from depth to seismic time using a well survey and then the synthetic trace compared with the real seismic data at the location of the well (note the simulated trace spliced in the middle of a real seismic line in the right hand panel).



Notes to Figure 8

This west to east seismic line is from the Northern part of Site 1 on the eastern flank of the Forties 5 area. The line illustrates the key seismic markers including the Top Forties formation and the calibration with well 22/9-3. The line also illustrates the eastern limit of the Forties fan system where the Top and Base Forties picks come together and difficulty of picking the Base of the Forties formation in this area.



Near Top Balder
Top Sele
Near Top Forties
Near Base Tertiary
Near Top Lower Cretaceous
Base Cretaceous Unconformity

Figure 8 - East-West seismic line through well 22/09-3 (Everest Field Well)

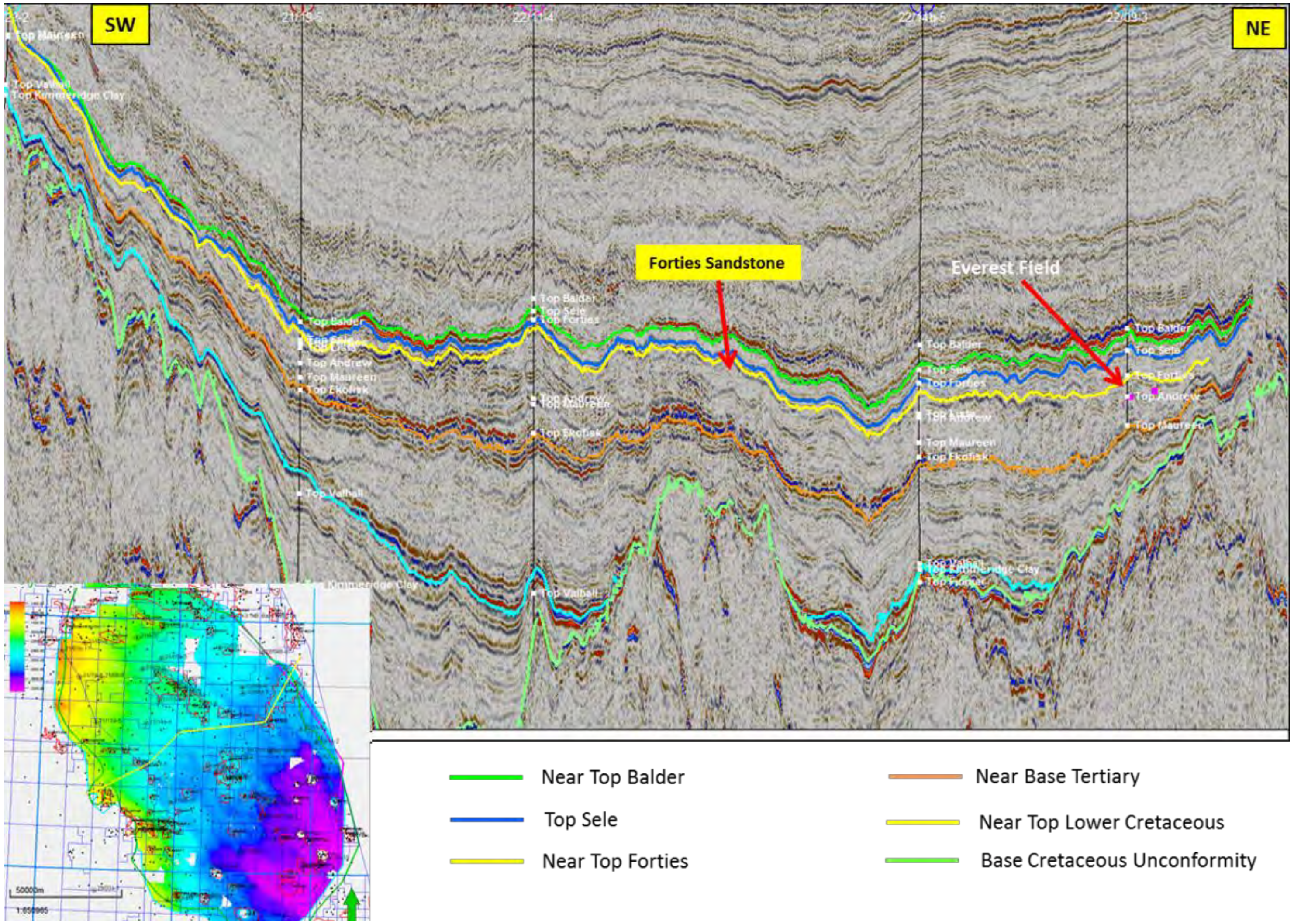


Figure 9 - SW-NE seismic line across the Forties 5 aquifer

Notes to Figure 9

This SW-NE line across the full extent of the Forties 5 aquifer shows the large scale subsurface environment of the potential storage reservoirs and the underlying and overlying formations. To the west the steep dip up towards the basin margins are clear and the deep structure which has been buried by the Cretaceous and Palaeocene intervals. Note that this section is 120km across and only a few hundred metres from top to bottom. The structures therefore look much steeper than they are in reality.

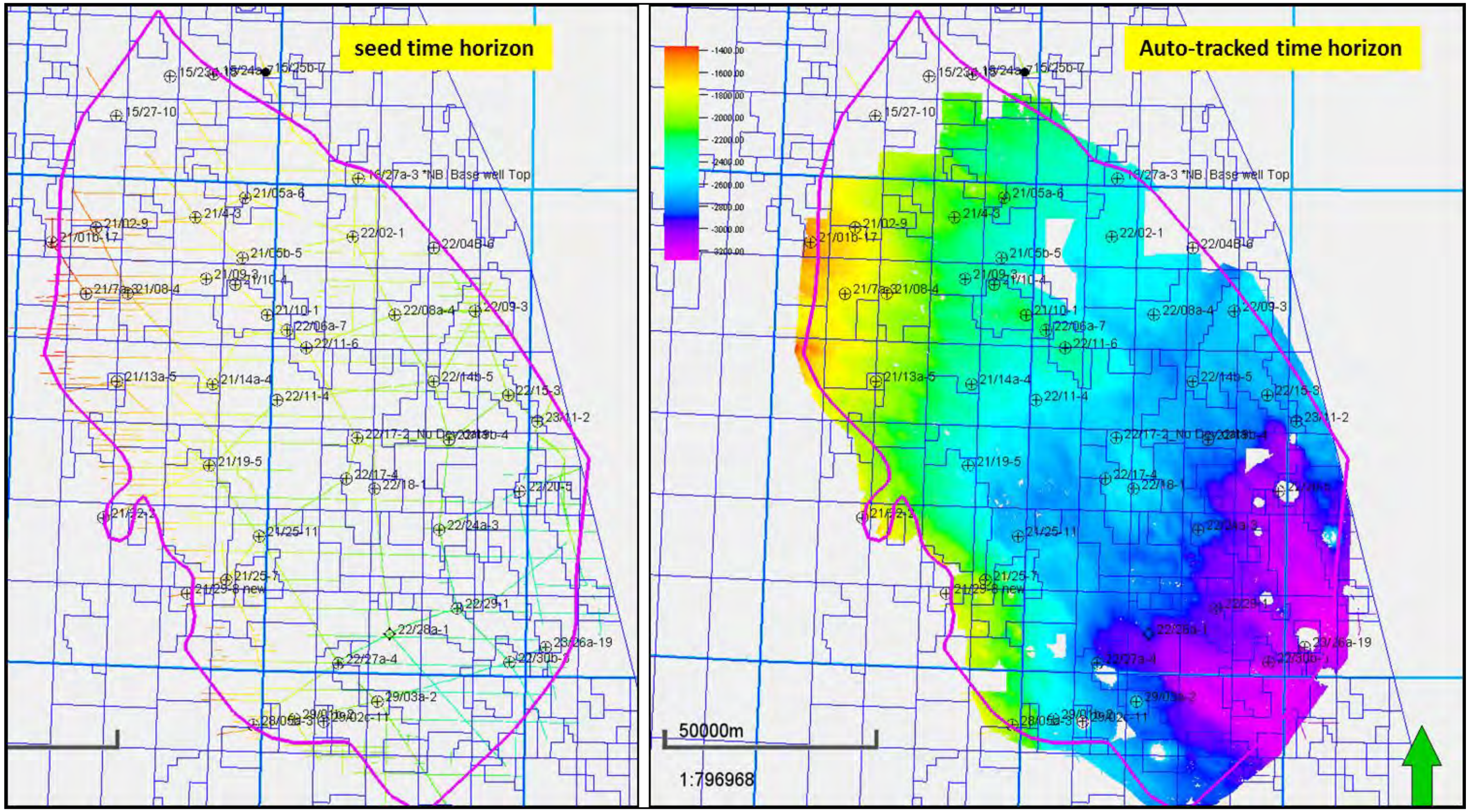


Figure 10 - Top Forties Sandstone time horizon

Notes to Figure 10

Where seismic data quality is good, modern seismic interpretations enable a framework interpretation to be put in place and used as a seed from which to grow a computer auto-tracked interpretation, which can then be carefully checked by the interpreter. This figure illustrates the input and output of this process.

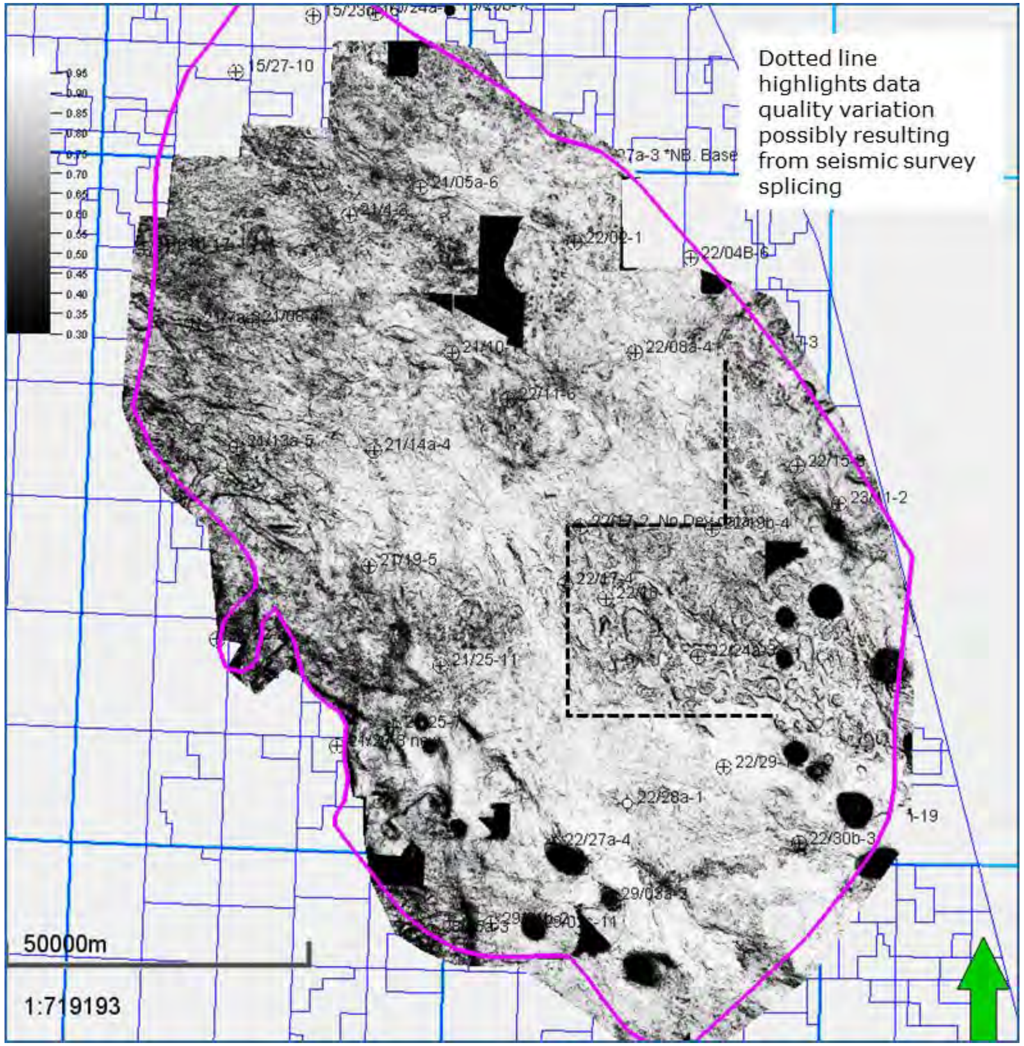


Figure 11 - Forties Sandstone Coherency Slice

Notes to Figure 11

Coherency is an attribute computed from the 3D seismic data volume, which compares one seismic trace with its adjacent neighbours perhaps 25m away over a specific zone of interest. High coherency (white) results when the seismic data is highly similar. Low coherency (black) results when there are rapid changes in the seismic data. This attribute is particularly useful for identifying subsurface changes resulting from faults, which present themselves as dark lineaments on the display. The analysis here suggests that there are few major faults within the Forties 5 aquifer area within the Forties formation. This attribute can be impacted by the "quilted" nature of the mega-survey.

Amplitude extractions from the seismic volume have been made; these show the approximate distribution of the sand fairways (red, yellow and greens). An example is shown in Figure 12, the main sand input is from the NW and this forms a large elongate NW-SE trending dispersal system. There is also minor lateral input from the west, which forms smaller E-W trending fans. Hydrocarbons within the oil and gas fields cause a dimming of the seismic amplitudes Figure 12.

The Top Forties time horizon was gridded using a grid increment of 100x100m. This was then depth converted using an oil industry standard VoK methodology. The velocity gradient or K value was derived from the average of three wells (Figure 13), K=0.425. A Vo value was derived at each well location such that when combined with the fixed K value the Top Forties depth surface would tie the well top. The Vo values at the wells were gridded to produce a Vo map.

On inspection of the Vo map it was noted that 3 wells in the SE had anomalously low values; these wells were drilled on salt diapirs. These 3 wells were removed from the final Vo map (Figure 14); however they still tie the Top Forties depth surface as a local correction was made.

The Top Forties depth surface is shown in Figure 15. It shows that the rugosity of the surface has been maintained and that no smoothing has been applied to the grid. A 3D view of the Top Forties depth surface is shown in Figure 16.

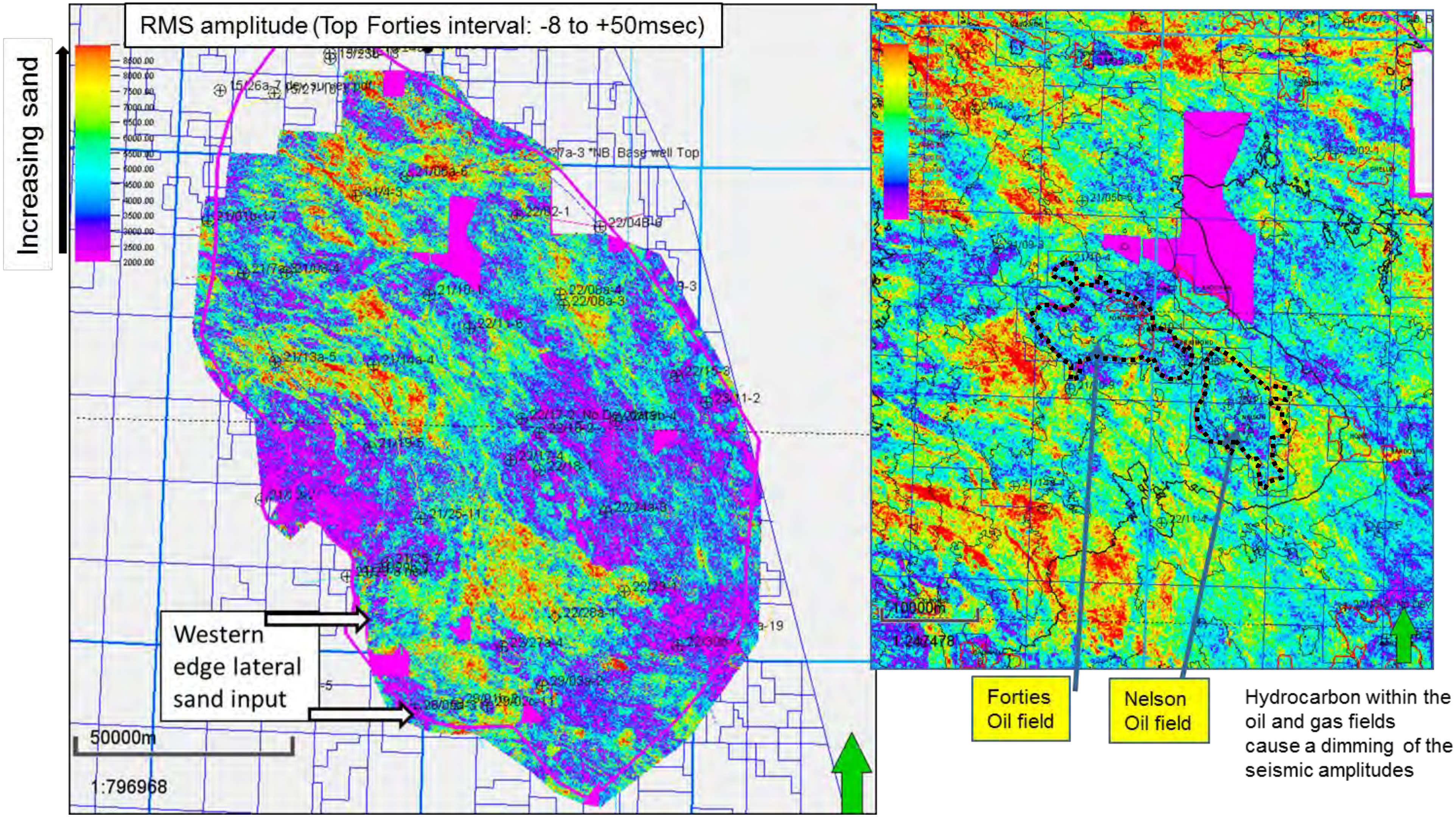


Figure 12 - RMS amplitude (Top Forties interval: -8 to +50msec)

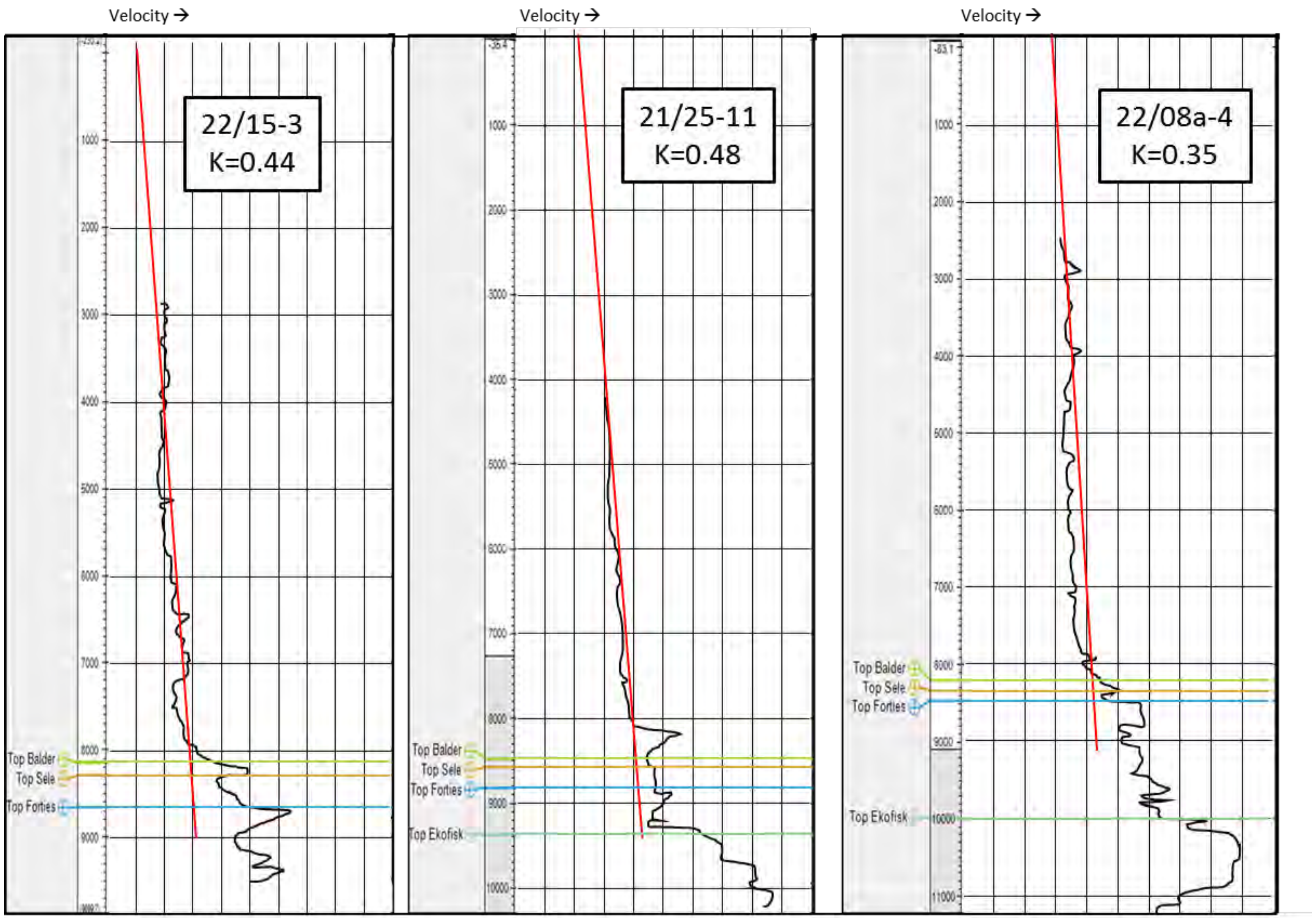


Figure 13 - Velocity logs with calculated gradient (k)

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Examples of three velocity logs, which are used to characterise the subsurface seismic velocities across the area, which enables the conversion of seismic time interpretations into depth models. A simple model of the velocity change is developed measuring the average value for K – the velocity gradient in each well

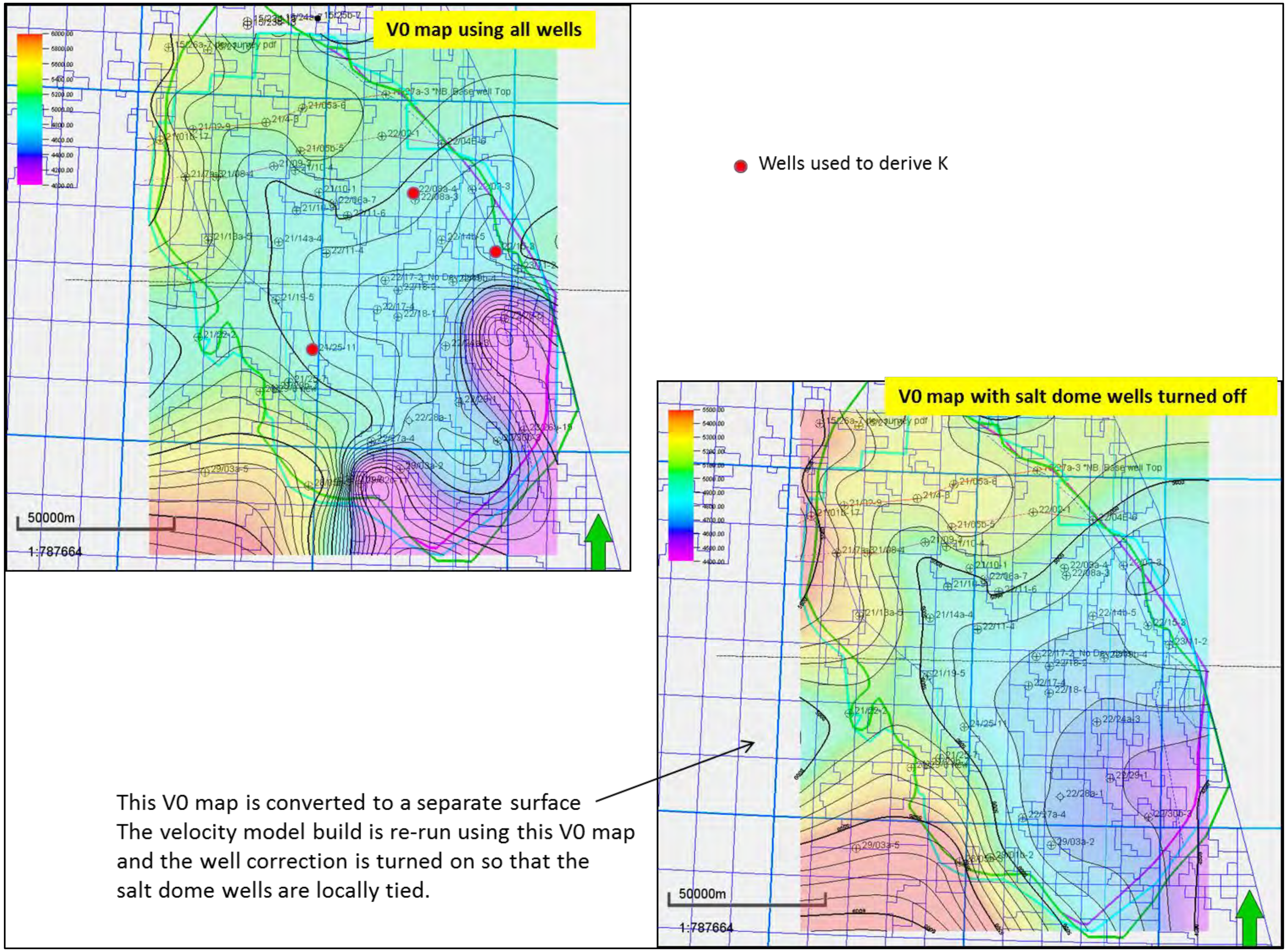


Figure 14 – Vo Mapping

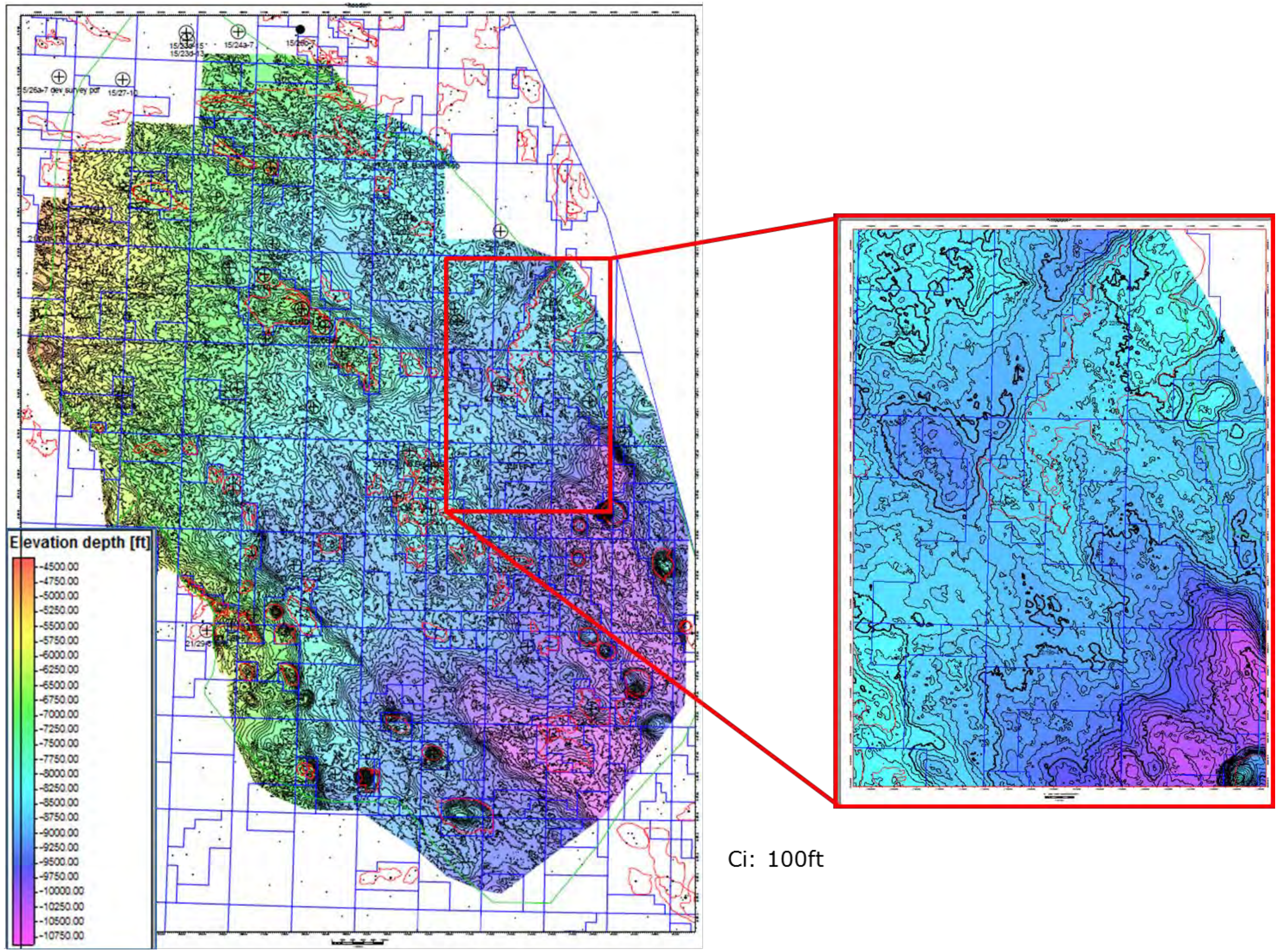
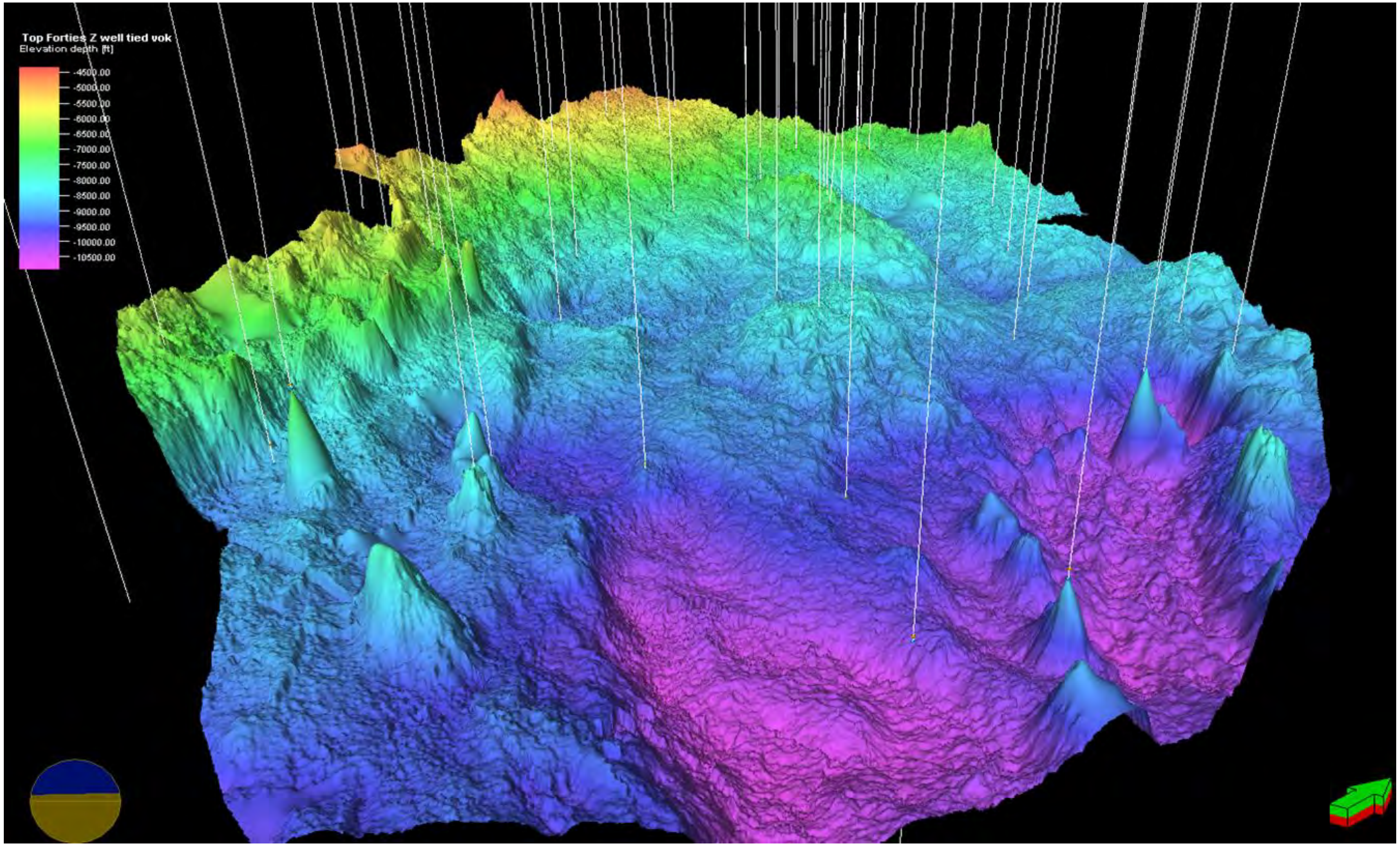


Figure 15 - Top Forties Depth Map

Notes to Figure 15

The depth map shows the overall depth trend of the Top Forties formation. The dark tightly bunched contour closures in the southern area are structures developed over underlying salt diapirs which have originated at deeper levels and have punched up through the overburden.



Note to Figure 16

This figure shows the central graben basin in blue and purple with the platform areas in the north and west in greens and yellows. The isolated spikes in the foreground are created by salt diapirs, which are sourced at much deeper horizons and rise up through the shallower overburden through the natural buoyance of salt. The Forties sandstone was introduced into the basin from large submarine flows which brought huge volumes of sand and mud from the shelf areas in the north and west.

Figure 16 - 3D view of Top Forties Depth Surface.

6.0 Static Modelling

With over 2000 well penetrations across the Forties 5 aquifer area it would be impractical to attempt to utilise all the available well data. A subset of 40 wells, along eight west to east sections, were selected and used to constrain the structural and property modelling Figure 17.

For each of the selected wells, Top and Base Forties sand was picked based on log data. An example across the centre of the area is shown in Figure 18. These were then used to tie the Top and Base Forties sand depth surfaces.

Quick-look methods were used to generate screening level petrophysical logs for the selected wells to guide the property modelling. Detailed petrophysical analysis of key wells will be carried out during the detailed Forties site modelling (WP5), once the final Forties site has been selected.

VShale

A simple Vshale was calculated using the following equation:

$VShale = (GR_{log}-GR_{min})/(GR_{max}-GR_{min})$

Simple Facies/ Lithology

A simple facies/lithology log (sand/non-sand) was created based on a Vshale cut-off of 45%, this was checked against the neutron density log cross over and was found to be providing a good predictor of sand facies.

Porosity

A VShale corrected density porosity was calculated and checked against core data where available:

$PHID = (RHOB-\rho ma)/(\rho fl - \rho ma)$

$PHIDc = PHID-(Vshale*PHIDSH)$

Where:

PHID= density porosity
RHOB = Log bulk density
PHIDSH = density porosity or shale
ρma = grain density = 2.65 gm/cc (Clean quartz)
ρfl= fluid density = 1 (assumption for oil and water)

No borehole correction or gas corrections were applied. Where these were observed the calculated log was ignored.

NTG

Net to Gross was calculated in the wells using a 10% porosity cut-off. Rock with porosity below 10% were assumed to be non-net, those above net.

Structural Model Build

Top and Base Forties depth surfaces were used as the top and base of the 3D model. The Top Forties was generated from the depth converted seismic interpretation; the Base Forties was calculated from well thicknesses extrapolated from the selected 40 wells shown in Figure 17.

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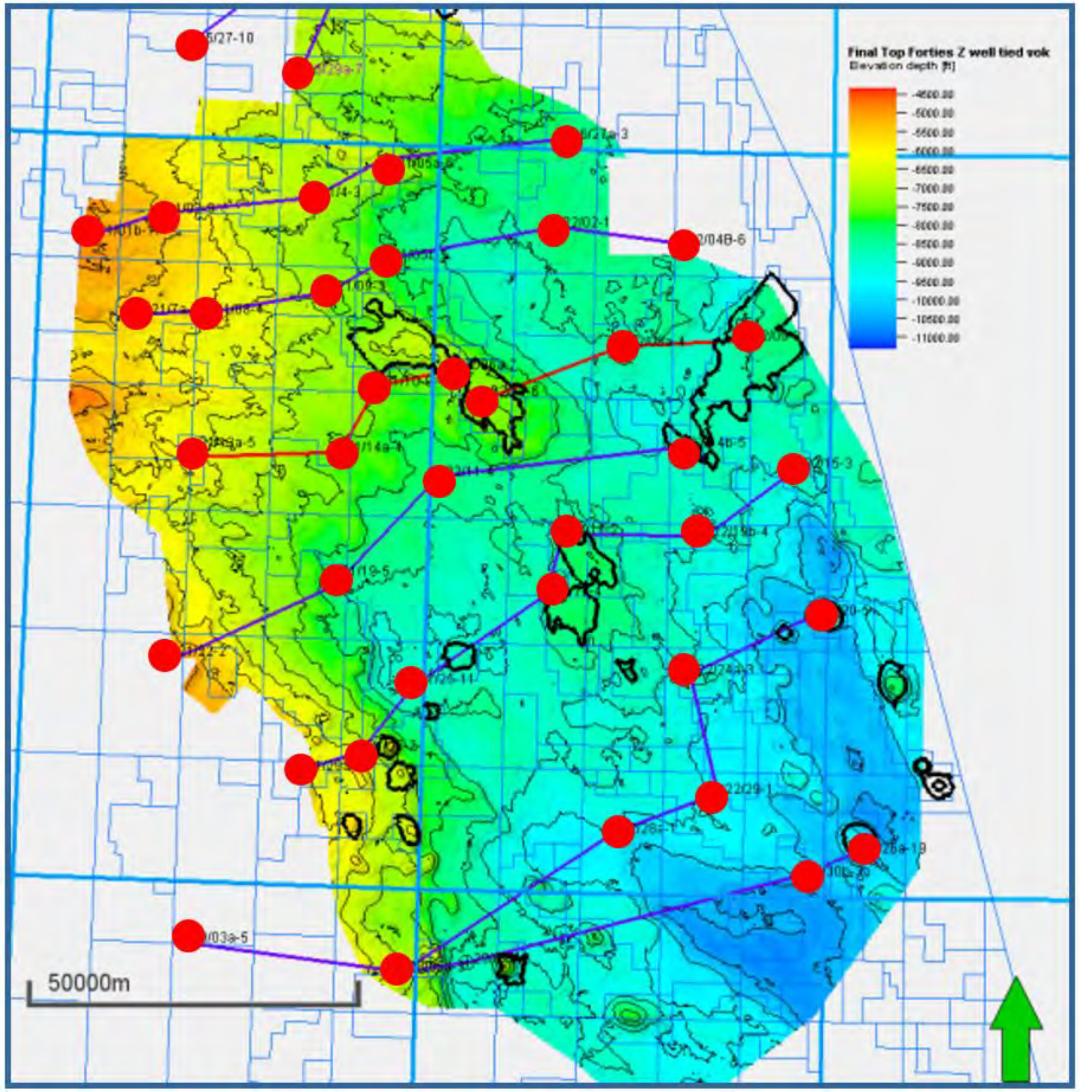


Figure 17 - Map illustrating the grid of well correlations used to characterise the Forties Aquifer

Figure 18 - Forties well correlation

The rapid regional seismic interpretation work suggested that whilst in detail the Top Forties was cut by some small scale faulting in some areas, there were no faults mapped that had the potential to displace the thick Forties formation to any significant degree (>200ft) other than perhaps along the steep western flank of the basin where seismic data quality at Top Forties is also degraded. The depth map in Figure 15 is a good representation of the Top Forties depth surface and for this regional modelling work faults were not explicitly modelled. This decision assisted the efficiency of model build and deployment without materially impacting or distorting the results. Once a site is selected then the seismic data will be worked in more detail and faults may be introduced.

A large static 3D grid has been built with good vertical resolution, in order to capture the vertical heterogeneity and shales which will impact CO_2 migration. As it is known that the primary lateral CO_2 plume migration will be at the top of the sand package, the grid has been split into two zones with the top 45ft (14m) of the 3D grid retaining the highest vertical resolution.

Grid Statistics:

- Lateral resolution 250m x 250m.
- Upper zone 45ft: 15 layers = 3ft (1m) cells.
- Lower zone 75 layers = 2 – 8 ft (0.6 – 2.5m).

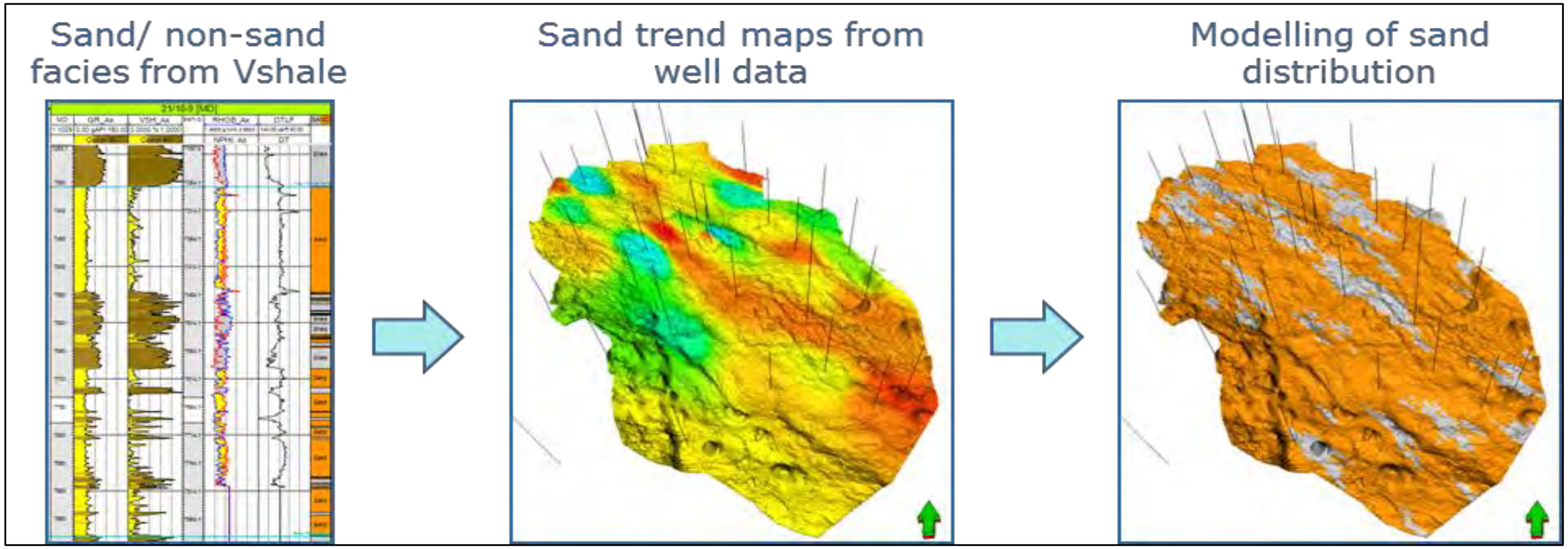


Figure 19 - Facies modelling workflow

Property Modelling

Of course there is detailed reservoir characterisation work on each of the hydrocarbon fields with a Forties reservoir. Whilst some of this is published, the challenge here is to develop a rapid and representative reservoir characterisation of the whole Forties aquifer system to enable a comparative test of potential injection sites to be established. To achieve this a broad grid of well data was selected from 40 wells in order to capture the overall trends rather than specific field detail. Modelling of simple facies, net to gross, porosity and permeability were carried out for the full Forties 5 aquifer area, using a standard static modelling workflow.

Well Log Upscaling

Well logs for each of the properties to be modelled were upscaled to the grid resolution:

- Facies: Most of (i.e. facies that is greatest proportion of cell).
- Porosity (net) : Arithmetic average biased to Facies
- Net to gross: Arithmetic average biased to Facies.
- Permeability: Not upscaled, modelled as a function of porosity.

Facies

The facies modelling workflow is shown in Figure 19.

Facies were modelled using a sequential indicator simulation method (SIS), this is an industry standard method for modelling of facies. A simple sand/ shale model is used to capture the reservoir heterogeneity and the baffling impact of shales both vertically and laterally. The facies are modelled elongate NW – SE to honour the depositional direction.

The modelling incorporates the facies log and the sand trend maps to ensure the correct distribution of sand and shale proportions within the model. Global sand proportions are based on the trend map volumes, which are similar to those observed in the wells (Upper Zone: 75%; Lower Zone: 78%).

The sand trend maps were generated from well data for the upper and lower zones to capture the regional depositional trends. These were checked against seismic attributes generated as a part of the seismic interpretation, and found to be capturing the same broad trends observed within the seismic. With more detailed analysis and more time, it is likely that seismic attributes could be used

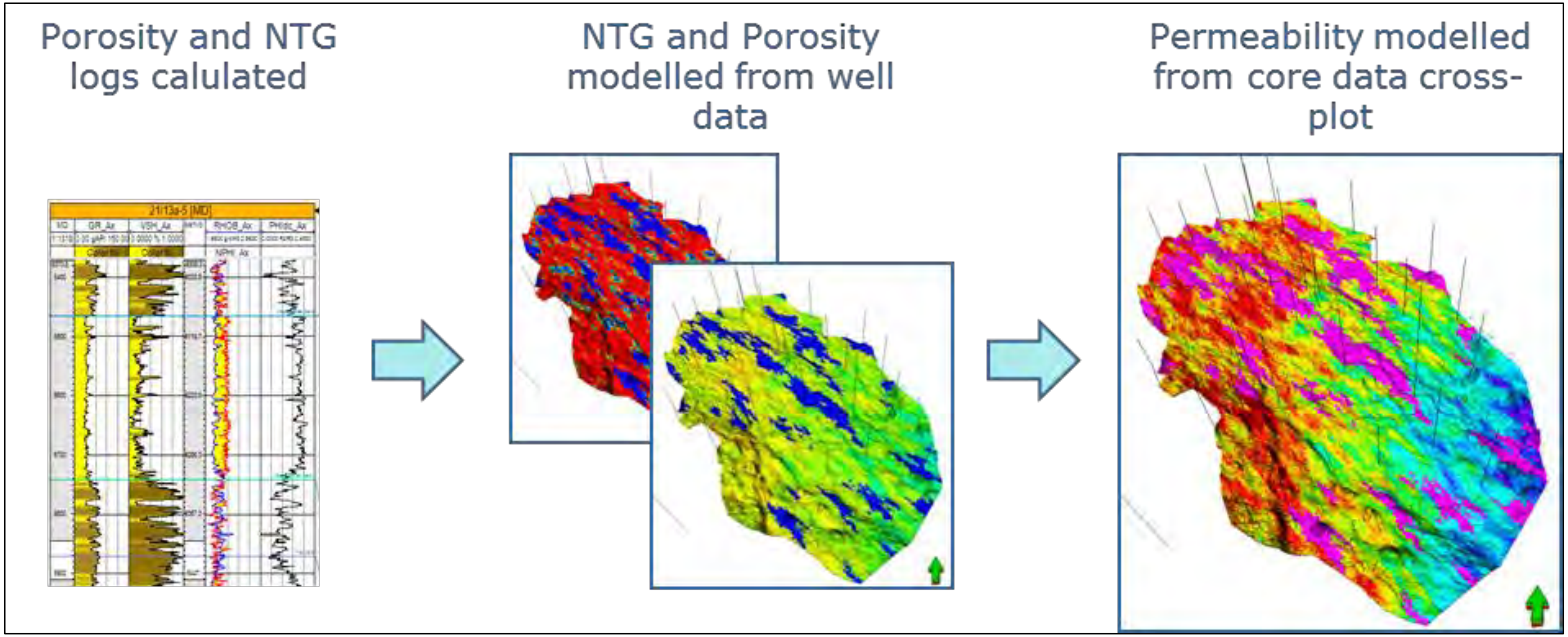


Figure 20 - Property modelling workflow

to further refine the sand trend maps. Such an approach would need to account for the effects of reservoir fluid types on the seismic response.

The variogram settings (range length and orientation) used are based upon a conceptual model of elongate channels/ lobes deposited from the NW, as documented in the reference literature (Hempton, et al., 2005).

- Variogram range (Major/ minor/ vertical): (25000m, 8000m, 10m).
- Orientation: -45 degrees.

The workflow for modelling net to gross, porosity and permeability is shown in Figure 20.

Net to Gross

Net to gross is modelled within the modelled sand facies based on the well data. Non sand facies are assumed to have a net to gross of zero. Due to the selected resolution of the model the majority of the sand has a NTG of 1. However the NTG modelling allows the impact of thinner shales below the grid resolution to be captured. The NTG is modelled using the following variogram settings:

- Variogram range (Major/ minor/ vertical): (12000, 4000,10).
- Orientation: 315 degrees.

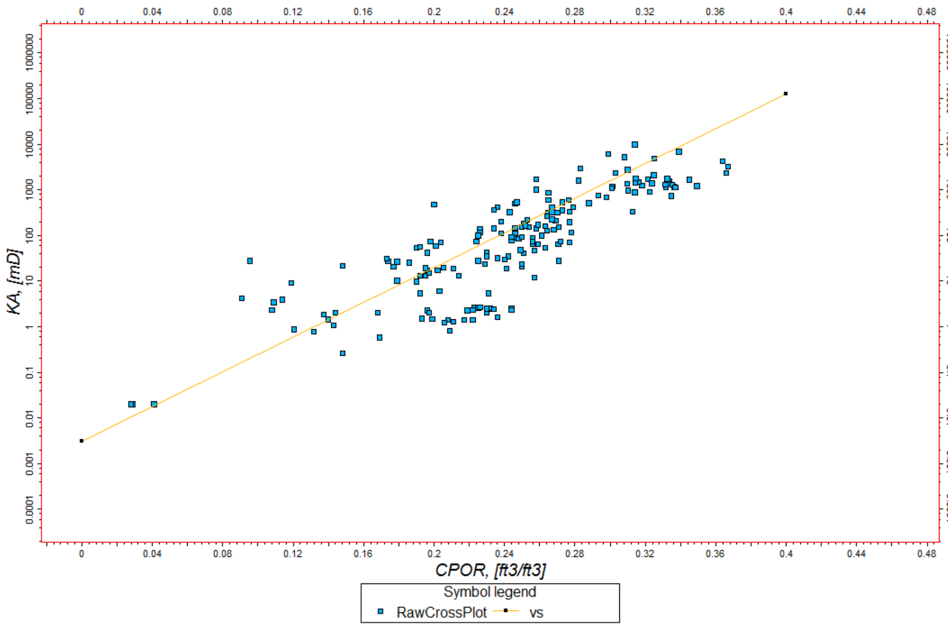
Porosity

In a system that is over 150km long, less than 0.25km thick and covering a depth range of around 1.5km, the depositional trends from NW to SE are a dominant feature in the distribution of porosity. Whilst a depth influence cannot be excluded, at this stage none has been explicitly deployed. The result shows a depositional trend with a reduction in average porosity from the NW – SE. This was captured within the model by creating a trend map of average porosity per zone from the well data.

Porosity is modelled within the sand facies based on the well data and the regional depositional trend map. Non sand facies are assumed to have a porosity of zero.

The variogram settings used are as follows:

- Variogram range (Major/ minor/ vertical): (12000, 4000,10)
- Orientation: 315 degrees



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Permeability

Horizontal permeability was modelled as a function of porosity directly within the 3D grid. The function applied was derived from core data available for a selection of wells (Figure 21):

The function derived was:

Perm = $10^{(A*Porosity-B)}$

Porosity = Modelled porosity (in 3D grid)

A = constant from trend map (range 14 – 20.5)

B = constant = 2.5

There is a very strong depositional trend controlling the permeability with average values ranging from 700 mD in the north-west to less than 10mD in the south. Due to this, one of the constants within the function has been varied across the area using a trend map, to ensure the permeability trend is captured.

The permeability thickness (kh) is shown in Figure 22.

Upscaling for Dynamic Modelling

The final high resolution static model has too many cells for dynamic simulation (~31 million cells). The grid was therefore coarsened vertically to allow for reasonable run times.

Within the upper 45ft of the Forties the grid resolution remains unchanged (i.e. the same as the static model), this is to capture the heterogeneity detail where the CO_2 plume is expected to migrate. Within the lower section of the interval the grid was coarsened from 5 to 15 layers as less detail is required.

The following methods were used for the upscaling of properties:

- Net to gross: Volume weighted arithmetic average.
- Porosity: NTG weighted arithmetic average.
- Permeability (Horizontal): Arithmetic average.
- Permeability (Vertical): Geometric average.

These upscaling methods are widely used within the modelling of hydrocarbon fields.

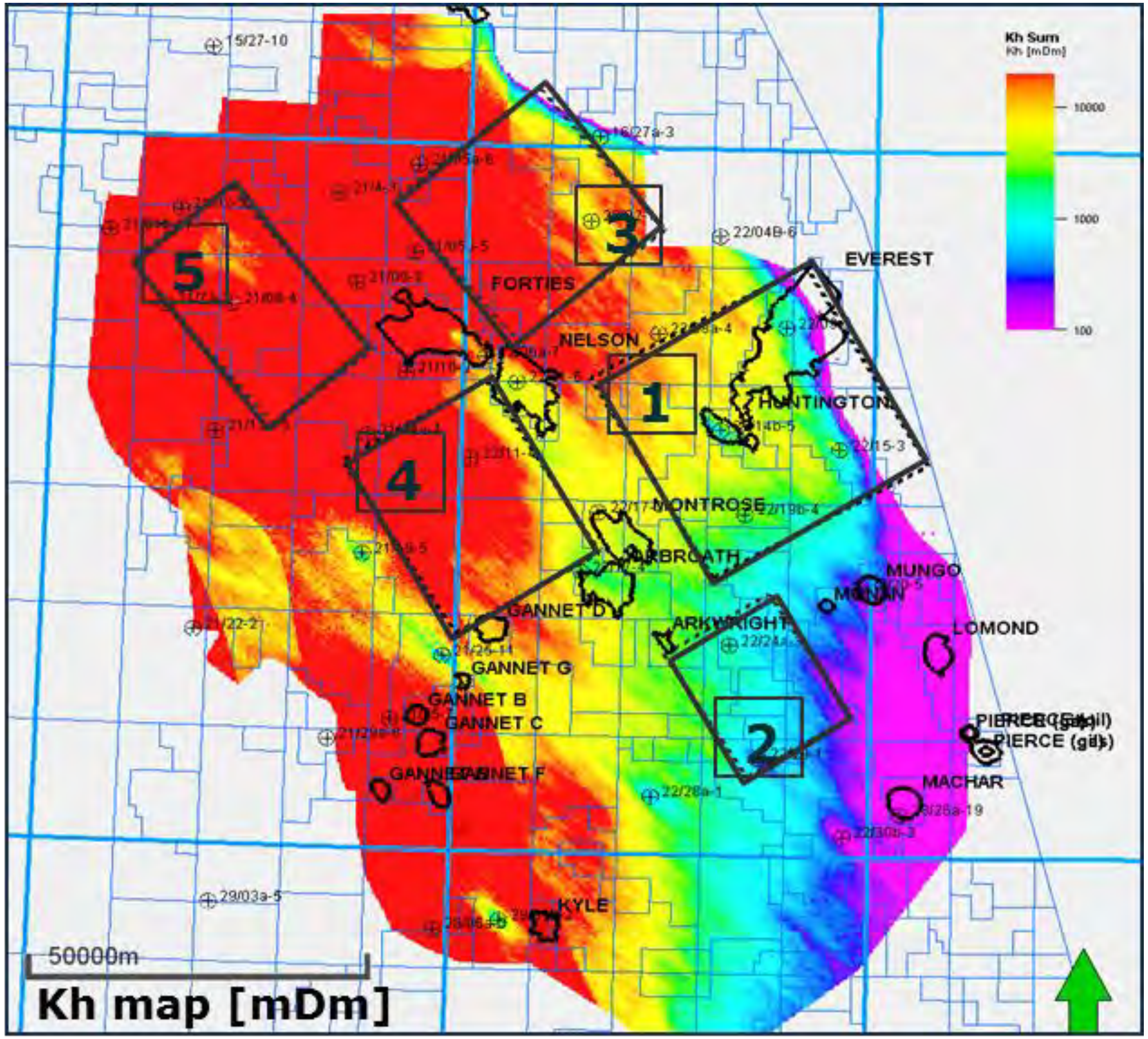

Figure 22- Permeability thickness map for Forties model

Notes to Figure 22

Kh represents the product of permeability and thickness and is a fundamental measure of reservoir quality and a control on injectivity. In broad terms, the injection rate is proportional to the Kh product within limits.

7.0 Selection of Storage Site Areas

Five sites for comparative testing were chosen across the Forties 5 saline aquifer region. These were chosen to be of a material size such they would meet overall project objectives and have been distributed around the Forties 5 area to test different parts of the fan system for potential injectivity, storage potential and importantly containment robustness. Since the purpose of selecting a Forties 5 site was to mature an open aquifer system as a key step to this strategically significant UKCS storage resource, areas with large hydrocarbon bearing closures have been largely avoided. This has also helped to reduce the potential containment risks associated with legacy oil and gas wells in high well density areas. The five sites selected for assessment are shown on the top surface map below (Figure 23).

The boundaries of the defined areas are not fixed at this stage. The boundary of the selected site will be better defined using the results of this study. The strategy for selecting each of the five target areas is described below. The rationale for selection considers both long term injection performance and containment confidence. These factors are captured in a “Common Risk Segment” map presented in Figure 29.

Site 1: The Eastern site was selected as the likelihood of containment is relatively high. It is bounded by a sand pinch out to the east, has a structural low (valley) to the NW and low structure with deteriorating reservoir permeability to the south. In addition, the Everest gas field is located in the NE of the site area, which is a proven structural trap. The objective is to inject into the low structural areas to the south of the site and the CO_2 will migrate towards the depleted Everest field. The Everest field is not the target storage site but increases confidence that containment within the area is high.

Site 2: The reservoir quality deteriorates towards the south of the Forties 5 storage region. Site 2 was selected to test if there will be any injectivity issues in the poorer quality areas. In addition, plume migration will be compared to the better rock quality areas.

Site 3: The reservoir quality in Site 3 is good. In addition, the site is bounded by a pinch out to the East which will stop any leakage out of the Eastern edge. However, the Forties sands connect to shallower sand packages to the North. This site was tested to assess the likelihood of the CO_2 migrating to the northern boundaries, where containment will be lost.

Site 4: Site 4 was selected as a central target area. There is a high risk of loss of containment in this area, with a leak path through the shallower Tay sands in the west and high well density areas to the east, corresponding to potential loss of containment through the older wells in the producing fields.

Site 5: Site 5 was selected to represent areas of potentially better storage capacity as the sand thickness and rock quality is very good. However, there is a potential leak path through the thick sand sequence to the north. The study will assess the likelihood of the CO_2 migrating into the leak path.

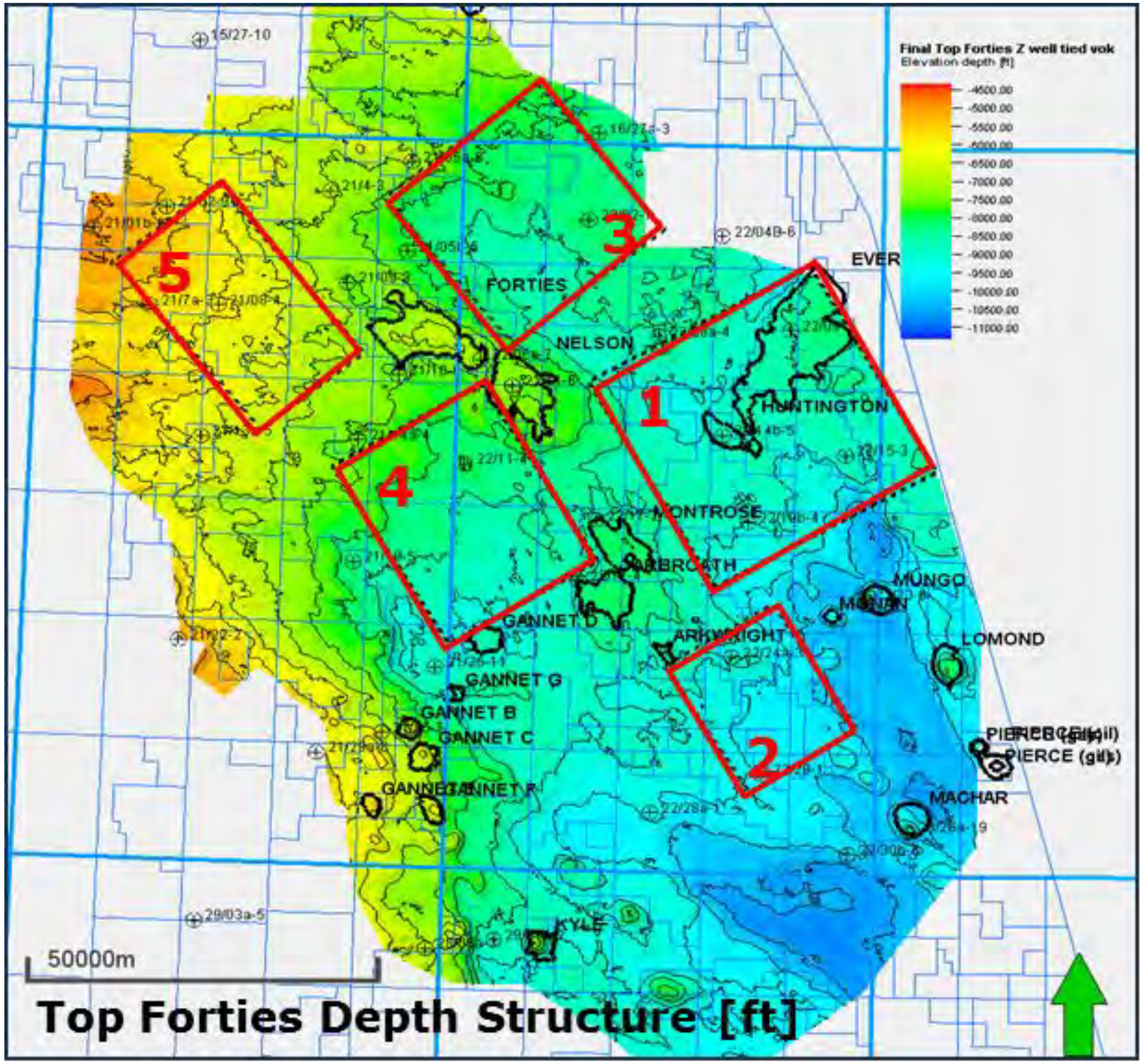

Figure 23 - Location of Five Test Sites within the Forties 5 Aquifer Region

8.0 Screening using Streamline Simulation

The Forties 5 aquifer extends over a massive area, 20000km^2. Due to the size, detailed modelling of the entire Forties area isn't practical for conventional simulation in a sensible timeframe. The objective of this study is to complete a comparative assessment of the injectivity, CO_2 migration and containment risk for five potential storage sites. Part of this assessment has been completed using streamline simulation.

Streamline simulation is particularly efficient in solving large, geologically complex models. It is a good tool for visualising the CO_2 flow paths from the injection wells. The streamlines and the plume extent at the end of the injection period for the 5 injection sites in this study are shown on the top reservoir map in Figure 24.

The illustrated streamlines are the calculated flow paths for CO_2 migration under injection. The CO_2 concentration is displayed on the streamline, high saturations are shown in red, with zero saturation in blue. The maximum CO_2 migration is seen at Site 4, where the plume remains within 16 km of the injection site after 50 years of injection. In this case, all five sites were assessed simultaneously due to time limitations. This resulted in no-flow boundaries being established between the sites and around the boundary of the area. These should be disregarded for this comparison as it would be very unlikely that all five sites would operate at the same time and so the focus areas are highlighted in Figure 24. As the CO_2 never extends very far from the injection site towards these boundaries, the plume footprint is not unduly affected by these boundary effects. This approach to modelling of five sites simultaneously has enabled a very rapid testing of sites at this screening stage ahead of detailed modelling work. It also

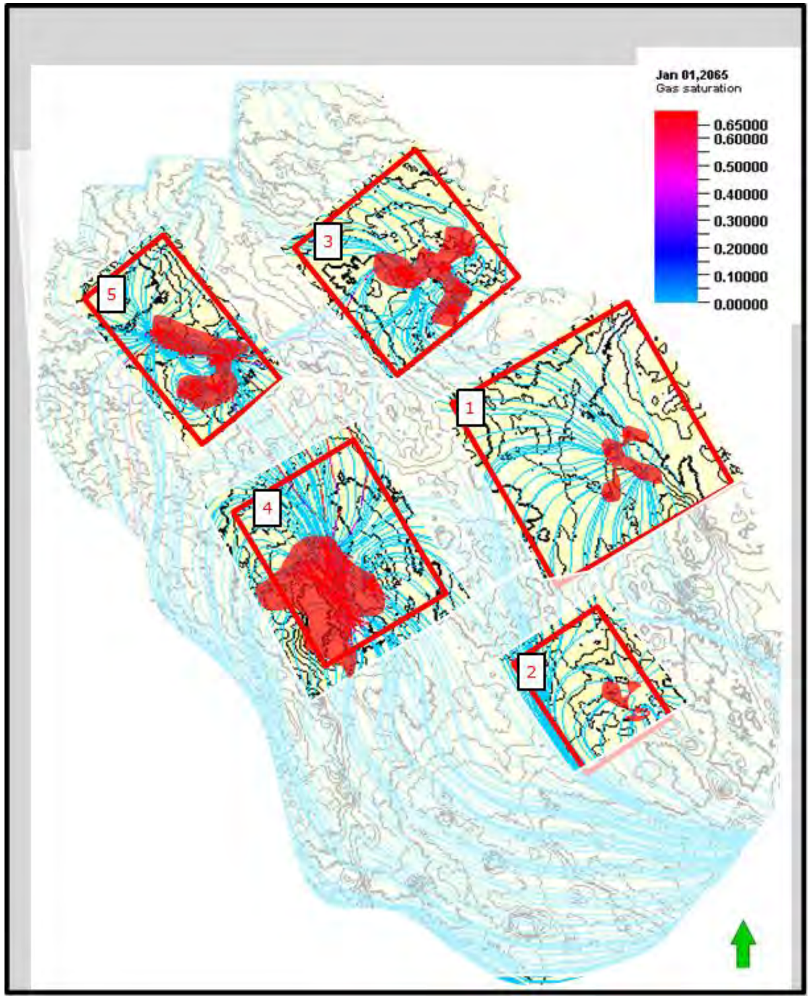

Figure 24 - Forties Aquifer streamlines and plume extent at the end of a comparative 50 year injection at each test site.

illustrates how the migration pathway for an injection site might be influenced and engineered by fluid injection in other locations.

Streamlines are only generated during active well operation (injection or production). For the initial screening a 50 year injection period was modelled using streamline simulation equating to a potential injected volume of 250MT. A 50 year injection period was chosen, as opposed to the generic 20 year injection period assumed in WP4, to assess likely flow paths for an increased CO_2 injected volume. The capability of injecting this volume and the migration of the CO_2 under injection was assessed for each site and the results of this, combined with an assessment of geological containment, were used to select a site to be technically progressed in WP5. A sector model of the selected site was modelled using Eclipse 100 to validate the results from streamline simulation and assess migration post injection. This is discussed in Section 12.

Model Input

The dynamic model was built in Petrel and FRONTSIM™ was used for simulation. The model has 10.2 million grid cells and the structural model and property distributions are described in detail in Section 9.0. No modifications were made to the rock property inputs in the dynamic model.

The relative permeability functions for a CO_2 and brine system are very uncertain. For the purposes of this study published analogue functions were applied (Burnside & Naylor, 2014). Drainage and imbibition data were used and end points are relatively high, therefore promoting the migration of CO_2. The same curves were applied to the entire model area. The relative permeability curves are shown in Figure 25:

The initial reservoir pressure was calculated using a pressure gradient of 0.01 MPa/m, 31 MPa at the datum depth of 4425 mTVDSS. It is understood that pressure depletion from producing hydrocarbon fields will impact CO_2 plume migration. Most fields within the Forties aquifer area are oil fields that have been developed under water injection support resulting in minimal pressure depletion. However, gas fields will have been depleted during the producing life of the field. As the Everest gas field is located within injection Site 1 a pressure sink was modelled in this area to capture the impact of the depleted region on CO_2 migration. The 2011 reservoir pressure from North Everest was sourced from a workshop paper (Rattan, Stevens, & Nguyen, 2011). A review of the production and pressure history for all of the fields within the Forties aquifer area was outside the scope of this study thus no other pressure sinks have been modelled at this stage. The initial pressure distribution, with and without the Everest field pressure sink, are shown in Figure 26. The Everest field is estimated to have a cessation of production date in 2026, well before any anticipated injection into the Forties aquifer site.

The CO_2 and brine system fluid description was incorporated into the model by adapting the PVT keywords. Dissolution of CO_2 into the brine and vaporisation of water into CO_2 were both modelled. The CO_2 properties with changing pressure were based on published data (Hassanzadeh, Pooladi - Darvish, Elsharkawy, Keith, & Leonenko, 2008). Water salinity was estimated to be 150000 ppm.

The conceptual development of 5 injection wells, injecting at 1MT/year per well was applied to each of the 5 sites. Wells were placed in structural lows, in the lower sand layers and in the better quality sands to optimise injectivity and CO_2 trapping. The wells were operated under a CO_2 gas rate control with a target rate of 1MT/year. The Bottom Hole Pressure (BHP) limit was set at an estimated fracture pressure calculated from a gradient of 0.017MPa/m (Breckels & van Eekelen, 1982), which equates to a pressure of 31MPa at a datum depth of 2900 mTVDSS.

The well depths, initial BHP and BHP limit (fracture pressure) per site are shown in Table 1.

The fracture pressure is approximately 60% greater than the initial (hydrostatic) pressure, except in Site 1 where the pressure has been depleted by production from the Everest fields.

Note on Reservoir Simulators

Two types of reservoir simulation approaches have been used in this work package, a conventional (finite difference) simulator and streamline simulator. Each of these techniques brings different benefits to the challenges of simulating flow in large and complex subsurface formations over periods of up to 1000 years. Both use a discretised cellular model of the reservoir geology as a starting point. This "Static Model" comprises many hundreds of thousands of building blocks which together capture the shape, volume and distribution of the subsurface formations. Each block is assigned properties such as porosity, permeability, saturation and pressure.

A conventional simulator such as Eclipse calculates fluid flow between cells in three dimensions. The simulation model computes the saturation change of each fluid phase (CO_2 and water in this case) and pressure of each phase, simultaneously for all cells in the model at each time step. Conventional simulators are the primary tool used in the simulation of oil and gas fields. In large models with two or three phases present such simulators can take several hours to run through a 30 year development cycle with commonly available computing technology. Running such models for very large number of cells (more than 1 million) or years (e.g. 1000 years into the future) is not routinely practical.

A streamline simulator such as Frontsim approaches the same problem in a different way, calculating fluid flow along one dimensional flow paths (streamlines). Here the pressures in each cell at any given timestep are used to develop streamlines. These are the paths along which fluid molecules will move under the calculated pressure gradient. Once these streamlines have been calculated, the flow calculations can be reduced to a single dimension along each of the streamline rather than the more complex three dimensional solution outlined above. A key simplifying assumption used by streamline simulation is that the system is assumed to be incompressible, allowing for each streamline to be treated as independent. When wells are added, taken offline or well rates are changed, the streamlines are recalculated. The approach works best for long periods of consistent flow, and requires continued injection or production to generate the streamlines.

Computational speed is achieved because the transport problem is decoupled from the 3D grid and instead solved independently along each one dimensional streamline. As a result, streamline simulation is generally used as a complimentary tool to solve specific problems where conventional simulation performance may be poor.

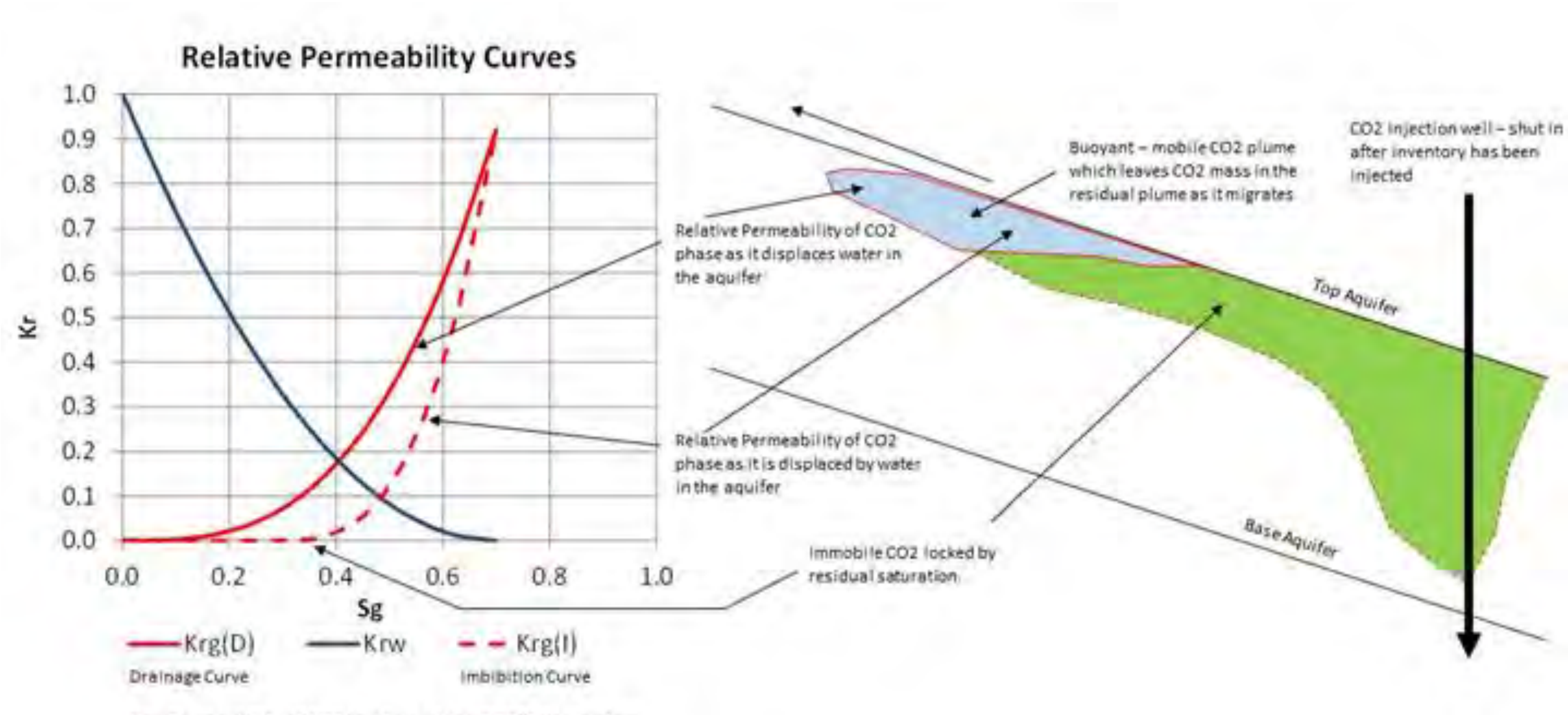

Figure 25 - Relative permeability functions

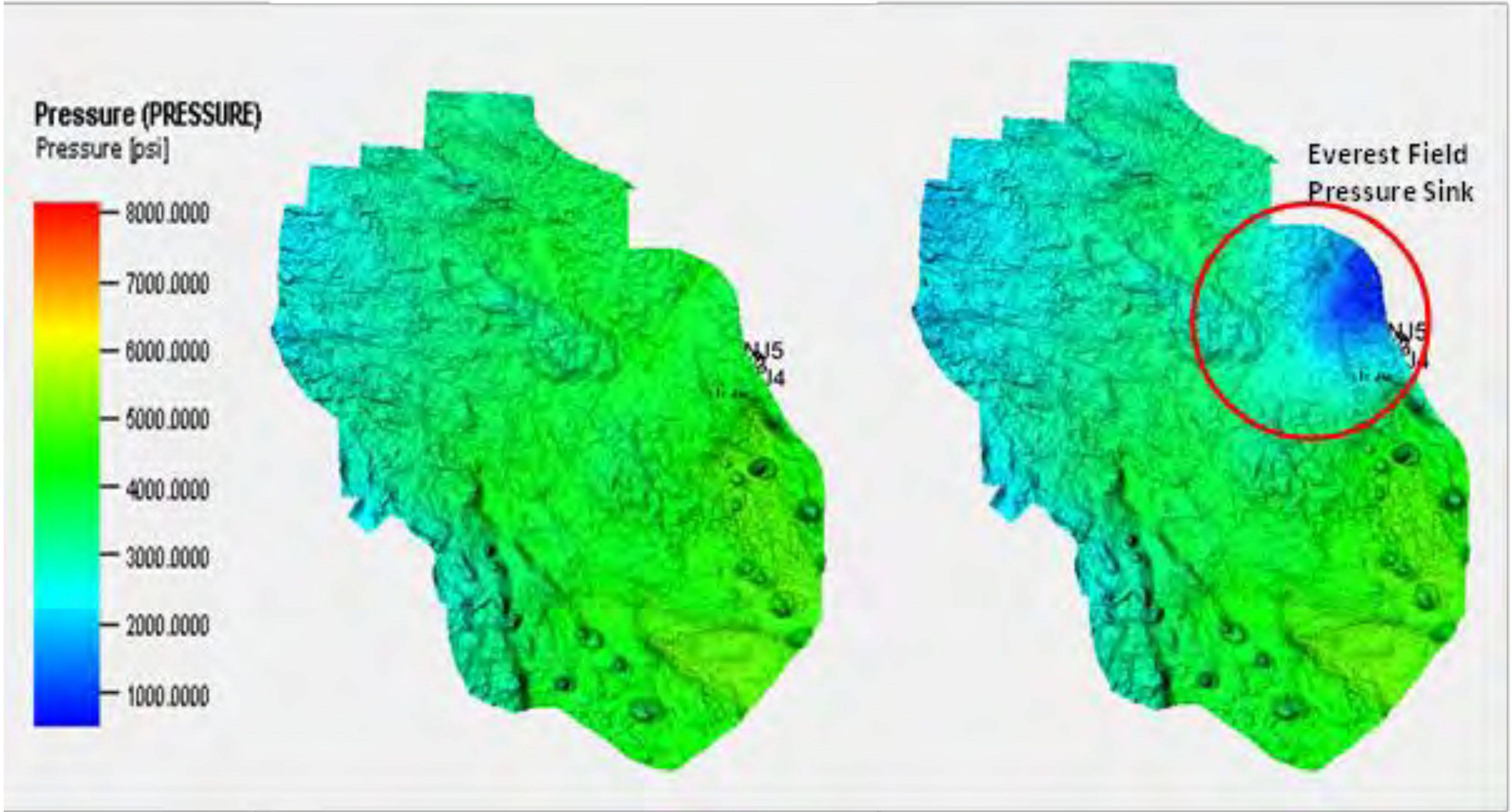

Figure 26 - Everest Field Pressure Sink (2011)

Injection Site	Well	Well Depth m TVDSS	BHP at start of injection Mpa	Fracture Pressure Mpa
Site 1 (Depleted)	INJ1	2813	19.7	48.5
	INJ2	2856	16.6	49.2
	INJ3	2877	17.1	49.6
	INJ4	2895	18.0	49.9
	INJ5	2756	12.3	47.5
Site 2	INJ1	3132	32.9	54.0
	INJ2	3050	32.1	52.6
	INJ3	3110	32.7	53.6
	INJ4	3096	32.6	53.4
	INJ5	3077	32.4	53.0
Site 3	INJ1	2767	29.1	47.7
	INJ2	2679	28.2	46.2
	INJ3	2784	29.3	48.0
	INJ4	2665	28.0	45.9
	INJ5	2657	28.0	45.8
Site 4	INJ1	2798	29.4	48.2
	INJ2	2822	29.7	48.6
	INJ3	2747	28.9	47.4
	INJ4	2807	29.5	48.4
	INJ5	2715	28.6	46.8
Site 5	INJ1	2100	22.1	36.2
	INJ2	2240	23.6	38.6
	INJ3	2006	21.1	34.6
	INJ4	1887	19.9	32.5
	INJ5	2190	23.0	37.8

Table 1 - Injection Well Depths and Pressures

9.0 Results

The migration of CO_2 for all five sites is shown in Figure 27:

The model was run using a well target injection rate of 1MT/year and the maximum BHP was limited to the fracture pressure. The injection rate target of 1MT/year per well is initially met in all sites except Site 2, but this rate is not sustained over the entire injection period in any site. The mass rate profiles are shown for each site in Figure 28.

The potential injection volume over a 50 year injection period, of 250MT, was not achieved in any of the 5 injection sites as all sites reached the BHP limit during the 50 years of injection. The volume injected into each site and key subsurface data is tabulated in Table 2:

Injection Site	Injected mass	Years on target mass rate	Average Reservoir Properties		
	@50 years (MT)		NTG	Permeability (mD)	Thickness (m)
Site 1	85	6	0.67	69	375
Site 2	33	0	0.72	10	420
Site 3	144	20	0.57	535	488
Site 4	188	26	0.67	446	476
Site 5	95	16	0.68	965	301
Total	**545**				

Table 2 - CO_2 migration for each site

Over a 50 year injection period, the injected volumes per site range from 33MT to 188MT, with a total injected volume of 545MT into the Forties aquifer.

The volume injected and migration of CO_2 at each site is controlled mainly by the fracture pressure limits used, rock properties and structural definition.

The CO_2 plume migrates vertically from the injection point with minimal lateral migration until it reaches the upper layers.

It is clear from the results that the lateral extent of the CO_2 plume migration is greater in the better quality sands in sites 3, 4 and 5 as a result of the higher injected inventory.

A higher degree of structural trapping occurs in Site 5 when compared with sites 3 and 4 due to the top surface rugosity and the location of poorer rock property baffles.

It should be noted that there is less confidence in the structural interpretation in this area due to limited well control and the quality of the seismic data is poorer.

Finally, it should be noted that the injected mass volumes in Table 2 should not be considered as final capacity estimates. This is because:

1. The runs were not optimised with regards to well locations and injection rates.
2. The runs were comparative only and injection stopped after 50 years.
3. The all-important BHP limit was not adjusted for the different geomechanical conditions at each site
4. The reservoir properties including the important parameter of permeability which directly influences injectivity have been derived from a small regional dataset.

The results are however useful for site comparison at this stage.

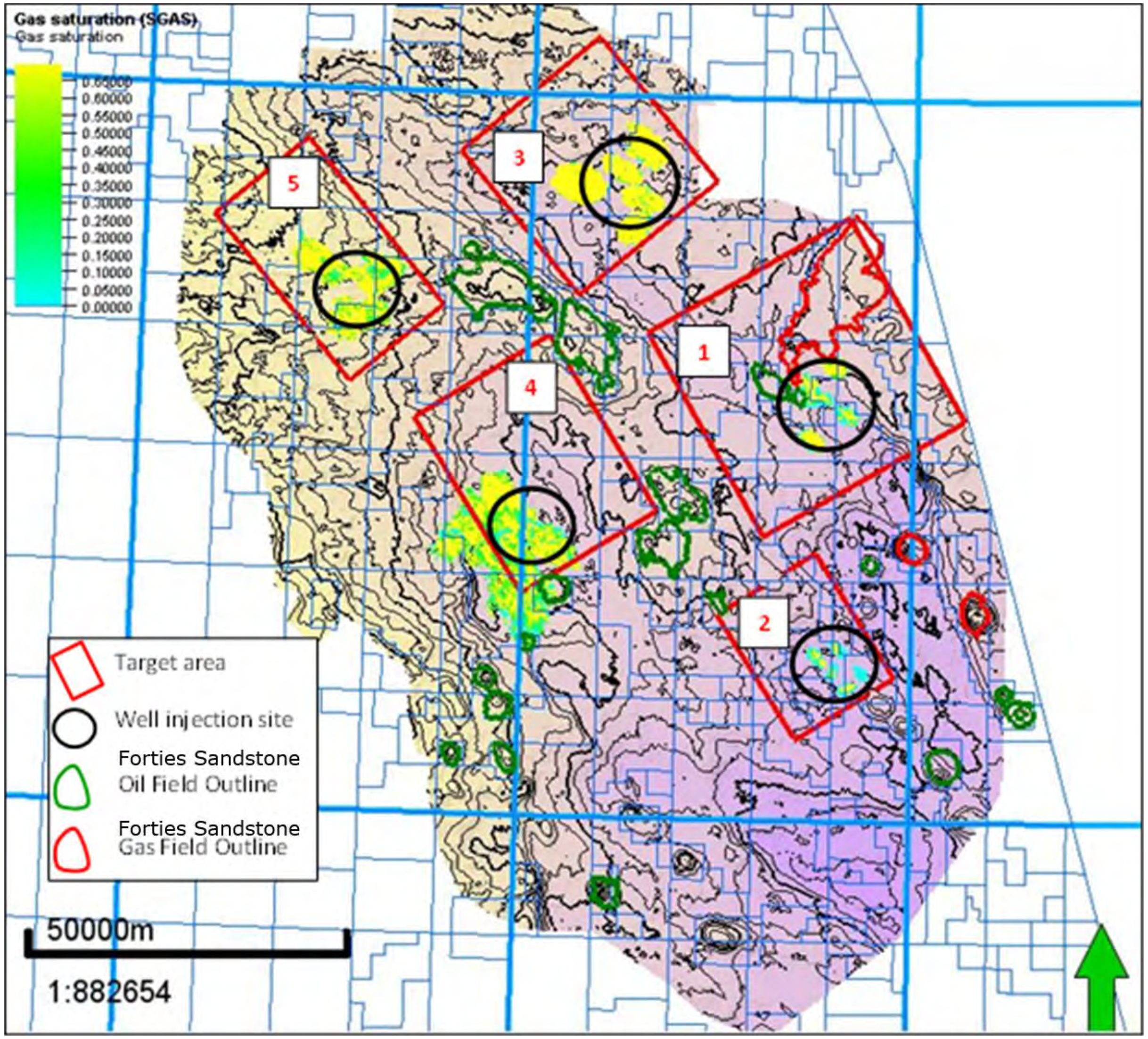

Figure 27 – Map illustrating CO_2 plume extend for each test site after a 50 year comparative injection test.

For the purposes of this study, one deterministic structural, property and connected volume case has been used for the site performance comparison.

Further sensitivities will be run as part of the subsurface uncertainty analysis in the more detailed modelling in WP5.

Northern Sites 3 and 5

Based on our subsurface understanding of the Forties aquifer system and the simulation modelling, the northern sites potentially present high potential storage capacities. Site 3 achieved 144MT and Site 5 achieved 95MT in the comparative test. This is a direct result of improved reservoir quality (sand permeability and thickness) close to the northern source point of the Forties fan system. This results in good injectivity performance with all wells meeting their initial injection target of 1MT/yr and maintaining it for several years until the maximum BHP limit is reached. However, Site 5 and Site 3 to a lesser degree are located in areas of reduced seismic data quality at the Top Forties target zone. This results from the increasing sand content of the overlying intervals in the Sele Formation. As the overlying interval becomes thinner and more sandy, there is in elevated concern around containment within the Forties aquifer itself. Notably the northern part of the Forties fan system, north of the Forties field is largely devoid of Forties system oil and gas accumulations. Whilst injection and storage capacity potential is significant in both sites, there is a more complex containment picture that would need to be resolved before progressing with the development of such sites to understand in detail the potential for migration pathways into thick overlying sands to the north and north east. As a result, neither sites 3 or 5 are recommended as the preferred initial Forties injection site for WP5

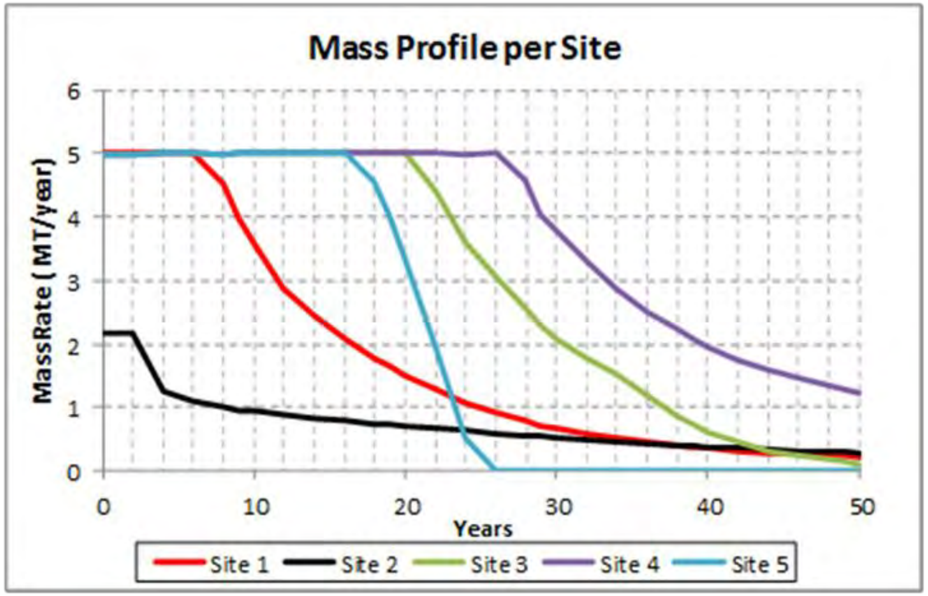

Figure 28 - CO_2 injection profiles for each test site

Western Site 4

Site 4 achieved the highest injection volume in the comparative test at 188MT. The reservoir properties in this area are good and the sands are well connected, which enabled elevated reservoir pressure to dissipate and wells to operate for a long time below the maximum BHP limit. The larger injected inventory results directly in a more extensive plume footprint at the end of the 50 years test injection period.

There are however a combination of containment issues for Site 4, especially along its western edge. Here there is an increased concern regarding containment linked with a potential migration path upwards through a thinned caprock interval and into the shallower Cromarty and Tay sands. These formations extend westwards and updip. Figure 30 shows a seismic line which runs westwards from the northern part of Site 4. It illustrates the increased dip up onto the basin margin. It also demonstrates how the Top Forties pick (in yellow) becomes more difficult to identify confidently to the west as the nature of the overlying formations changes and with it the acoustic contrast across the Top Forties. This is accompanied by a series of consequences including:

1. Hydrocarbons can now escape out of the Forties formation and migrate into upper intervals such as the Tay Sands. 21/13a-5 midway along the line has a strong hydrocarbon show in the Cromarty sandstone above the Forties.
2. An area to the North and west of the area which is largely devoid of oil and gas accumulations in the Forties formation.

The implications of this are that whilst Site 4 possesses excellent storage and injection characteristics, and has significant storage upside in the overlying sands, there is additional complexity regarding the containment mechanism which would require further detailed study. As a result, Site 4 has not been chosen as the preferred initial Forties injection site for WP5 at this stage.

Southern Site 2

The results indicate that injectivity risk is elevated at Site 2 compared to the other sites. The poorer reservoir quality results in a lower injectivity index per well, with most wells being unable to achieve their initial target rate of 1MT/yr . Furthermore, the simulated wells reach the maximum BHP limit early in their lives. This results in loss of injection rate and without well intervention or new drilling the injected rate at the site cannot be maintained.

For this test, the total injected volume to Site 2 was 33MT. Whilst further work on well placement and design could improve on this, it is beyond the scope of this project. These results show that whilst Site 2 may be engineered into a useful CO_2 Storage site, it should not be the first location to be developed in the Forties Open Aquifer system, despite its strong geological containment credentials. It is therefore not recommended for further work in WP5.

Eastern Site 1

Site 1 achieved a moderate injection volume in the comparative test. There is high confidence in CO_2 containment in Site 1 where the potential for alternative migration pathways is less apparent (Figure 29).

It should be noted that strong containment properties of the Forties caprock system across the region is well demonstrated by the diverse distribution of oil and gas fields with significant hydrocarbon columns across the area. Site 1 is flanked by Everest to the North, Montrose and Arbroath to the west and Monan and Mungo to the south.

At Site 1 the test injection site has been located in the aquifer downdip and to the south of the Everest field. This location was chosen with the objective of containing the full injected inventory in the open aquifer system, but with a secondary trap provided by the Everest closure itself in the unlikely event that residual trapping is insufficient to hold the injected inventory in place.

The Everest gas field demonstrates a proven structural trap within the site and as the field is significantly depleted it acts as a pressure sink and CO_2 will migrate towards the trap.

In Site 1 however, the reservoir quality is not as good as the northern sites. The injected volume during this study is 85MT compared to 95MT and 144MT for sites 5 and 3 respectively. It is considered that there is room for further optimisation of the well placement which will support injectivity and capacity. Streamline modelling suggests that the injected CO_2 does not reach the Everest field limits during the injection phase of this study.

Site 1 has been recommended as the focus of further detailed study work in WP5. It is recognised that there will be many challenges in developing an open aquifer system where the mechanisms for trapping are less familiar and are more difficult to understand than for simple buoyant trapping in closures. The combination of good quality reservoir, good caprock containment characteristics and the back up of a large closure up dip from the injection site with comparatively low legacy well density presents an ideal starting point for CO_2 storage development in the Forties 5 saline aquifer.

Figure 29 assembles a range of diverse risk attributes together on a single map or "Common Risk Segment" map. The map is illustrative of:

1. Forties reservoir depositional environment (from well data).
2. Hydrocarbon field distribution (from DECC data).
3. Areas of elevated cap rock containment risk (from seismic confidence map).
4. Areas of moderate and high legacy well density (from DECC well database).
5. Areas of poor injectivity risk (from static model Kh attribute).

The map highlights that Site 1 is the strongest candidate as an initial injection site. Site 4 is also a good candidate but has a much more complex containment character.

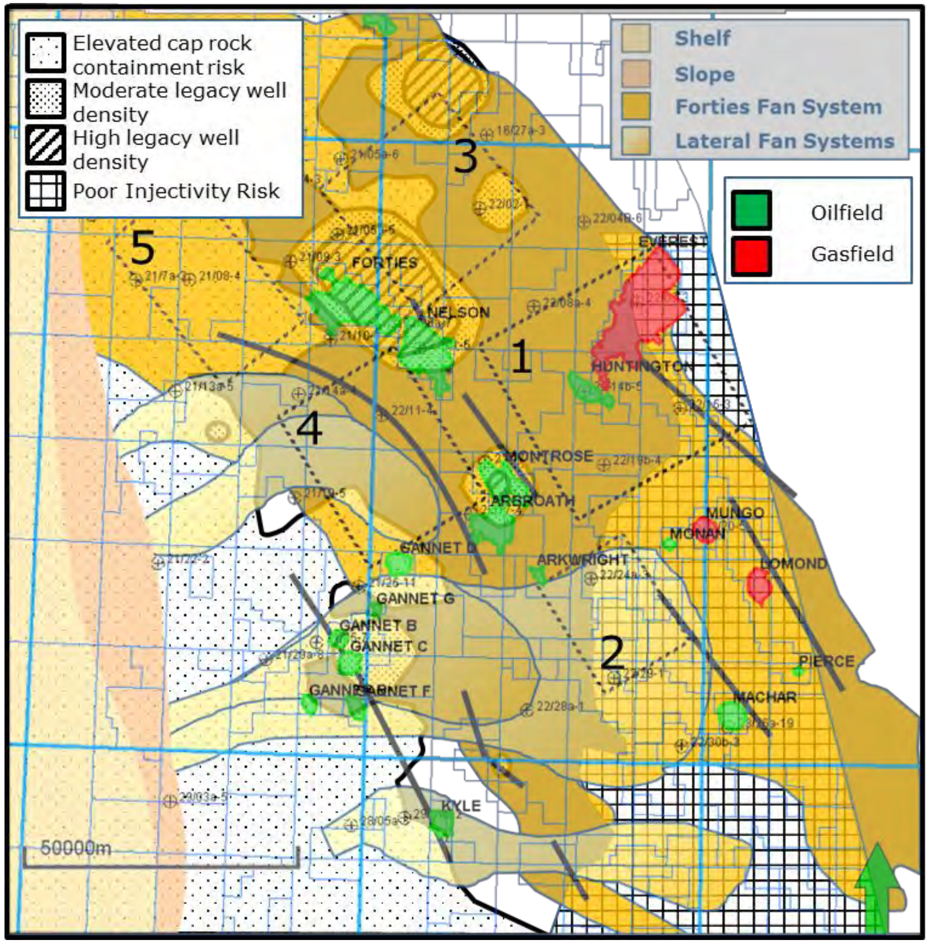

Figure 29 - "Common Risk Segment" map of the Forties 5 Saline aquifer area

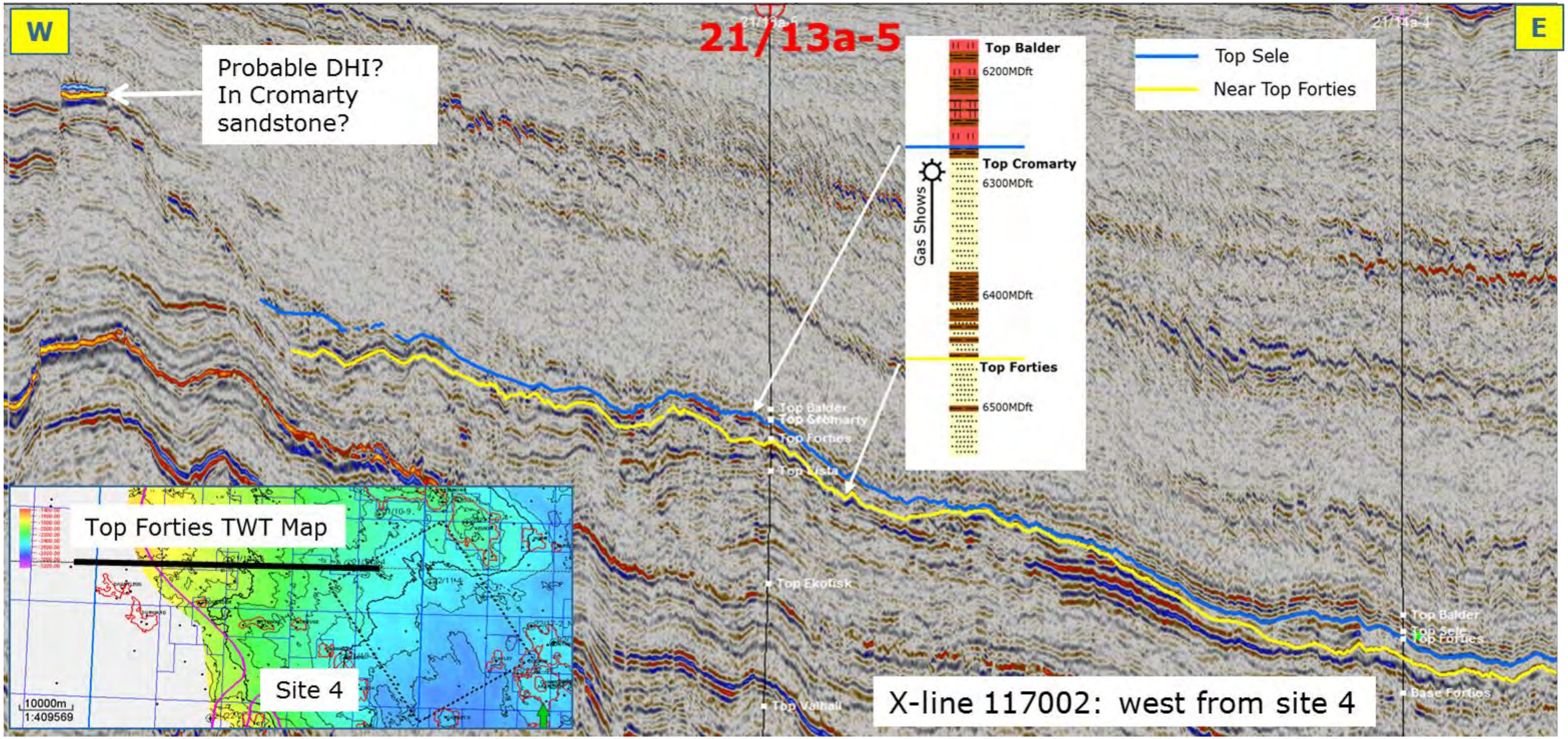

Figure 30 - West to East Seismic line from the basin margin towards Site 4

10.0 Storage Site Selection

The Forties 5 saline aquifer site was selected for detailed study as it is strategically important to start to progress large capacity open saline aquifer systems as potential storage sites. As such, no consideration has been given to the potential use of depleted Forties formation hydrocarbon closures for storage at this time. A key challenge of open saline aquifer systems is the geological containment of CO_2. In this study, the migration of CO_2 from a selection of five potential injection sites has been assessed to determine which site has the best combination of storage potential and containment from which to commence a Forties 5 CO_2 storage development.

At the suggested date of injection start up in 2030, almost all currently producing Forties formation oil and gas development projects will have ceased production and will have either been decommissioned or be under decommissioning. Potential tail end fields include Montrose, Arbroath, Forties and Pierce. The test injection sites have been located to minimise any immediate interaction with these tail end fields, although with such a well connected system, some reservoir pressure interference is possible. No EOR synergies between the test sites and the tail end fields have been considered. Elsewhere, high well densities arising from large early petroleum development projects are captured as a risk segment and represent a potential containment concern

The geological and structural assessment of the area, in addition to the dynamic modelling results, indicates that there is a slightly elevated concern about containment in sites 3, 4 and 5. Site 2 has a higher risk of lower injectivity. For these reasons, these potential additional storage sites will not be evaluated further as part of WP5, although they do remain as strong candidates for potential future storage sites within the Forties aquifer system.

Whilst all sites present viable CO_2 storage targets, Site 1 is considered to be the best site to start with. At Site 1, the storage potential is good and the containment picture is relatively simple and robust. The Everest gas field, which is located within Site 1, provides both regional evidence of containment and a pressure depleted area that CO_2 will migrate towards. Site 1 has been designed such that the closure afforded by the Everest field is not exploited in the base development, but it provides valuable back up in the unlikely event that the CO_2 plume moves faster than forecast. It also presents potential significant upside storage capacity potential.

Whilst no significant well placement optimisation was completed on any site at this stage, injectivity in Site 1 is not as well developed as some of the alternative sites. This is especially so in the south as the reservoir quality deteriorates. During detailed study of Site 1 in WP5, the well design and placement will be optimised to maximise the capacity for the site.

The screening results are illustrated in Table 3.

Test site	Level of Concern (1 – lowest to 3 – elevated)			Notes & Comments
	Reservoir Quality (Injectivity)	Geological Containment	Engineering Containment (Wells)	
Site 1	1	1	2	Everest field structure provides fall back to residual trapping containment
Site 2	2	1	1	South has relatively lower quality reservoir properties
Site 3	1	3	1	Potential migration pathways to North and East
Site 4	1	2	3	Potential migration pathways to West and also into high density legacy well areas of Nelson and Forties
Site 5	1	3	1	Potential migration pathways to North

Table 3 - Site assessment summary

11.0 Storage Site Validation

The streamline approach to modelling across the very large area of the Forties 5 saline aquifer has enabled rapid comparative testing of the injection performance of each of the five sites in a quantitative manner. Section 8 outlines some of the differences between streamline and conventional simulators and with a smaller area defined at Site 1 it was possible to use conventional simulation to test and validate the early findings of the streamline work. In particular the calculated streamlines become less stable once the wells are closed in at the end of the injection period and it was helpful to use the computational rigour of a conventional simulator to check the post injection plume movement.

A sector model was extracted from the full Forties aquifer model over Site 1. The area was then modelled using conventional simulation using Eclipse 100.

No grid refinement was carried out at this stage and the input properties were unchanged from the streamline simulation model, as described in Section 8.0.

The target injection rate is 1MT/year per well, for the same 5 wells that were assessed using the streamline simulation. This time, the wells injected for 20 years and then they were shut-in.

The model was run for a further 1000 years post injection to forecast the migration of the CO_2 plume over that time.

The wells were long horizontal wells located as shown in Figure 31.

The target rate of 5MT/year was maintained for 7.5 years and the total mass injected was 70MT. The profile is shown in Figure 32.

Each well behaved differently, with only 2 wells still injecting at the end of the 20 year injection period, having injected approximately 18MT each at that time. The well profiles are shown in Figure 33.

The well performance is controlled by the local reservoir heterogeneity and the structural definition. The wells with the longer injection well life are generally located in better connected sands. Further optimisation will be carried out in WP5 to optimise well length and location.

The plume migration at the end of injection and after 1000 years is shown in Figure 34.

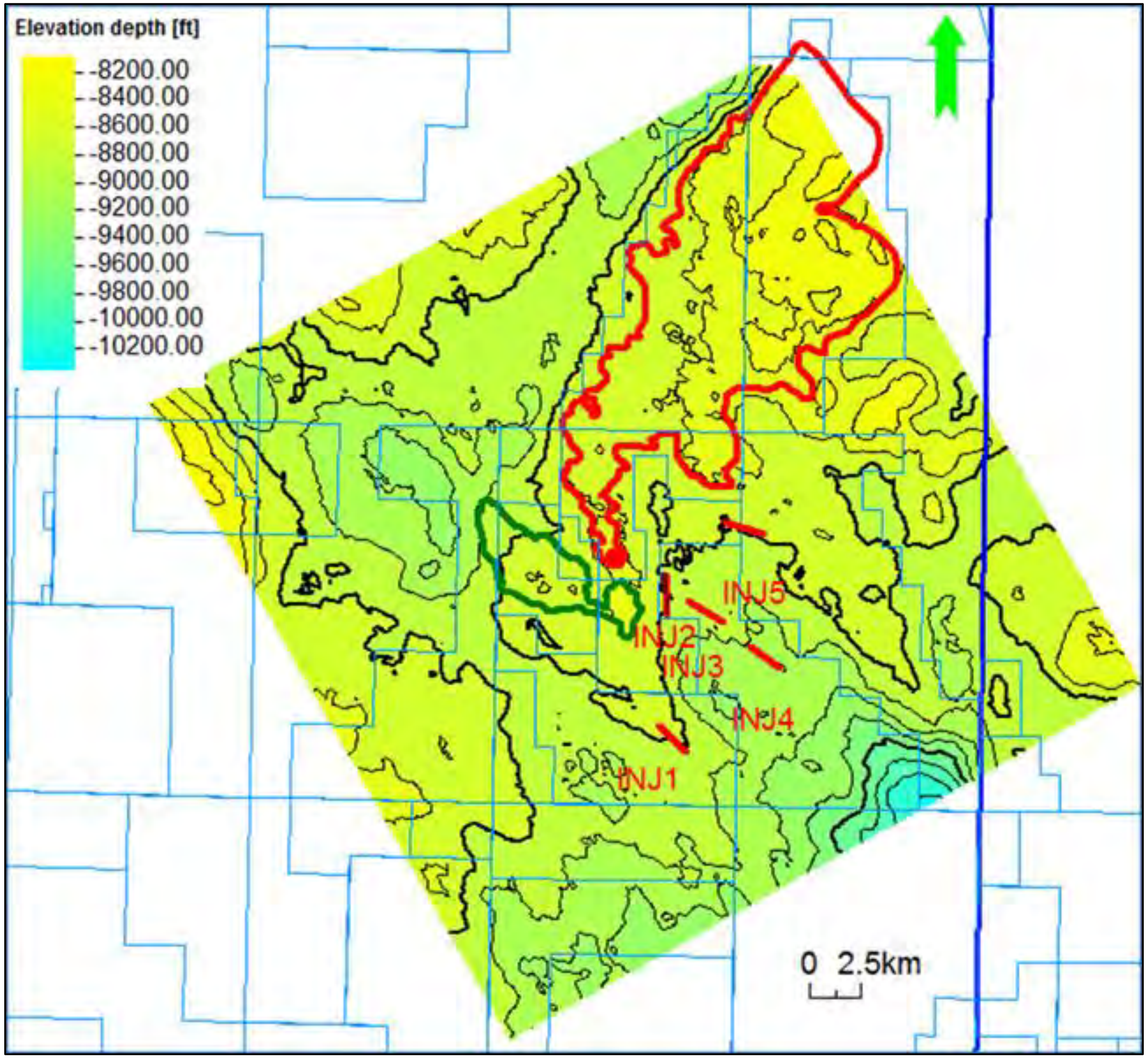

Figure 31 - Site 1 Well Locations

Notes to Figure 31

Figure 31 shows the layout of Site 1 overlaid onto a depth structure map at the Top of the Forties formation. The location of test injection wells are shown by five short red lines that represent the horizontal well sections. The red contour and green contour highlight the hydrocarbon water contacts for the Everest gas field and Huntingdon oilfield respectively. Both fields are estimated to reach their decommissioning points before injection starts. The injection site has been designed to hold the injected plume in an open aquifer system, but benefit from the additional assurance of an updip migration pathway into the depleted Everest gas field in the unlikely event that plume mobility is greater than anticipated.

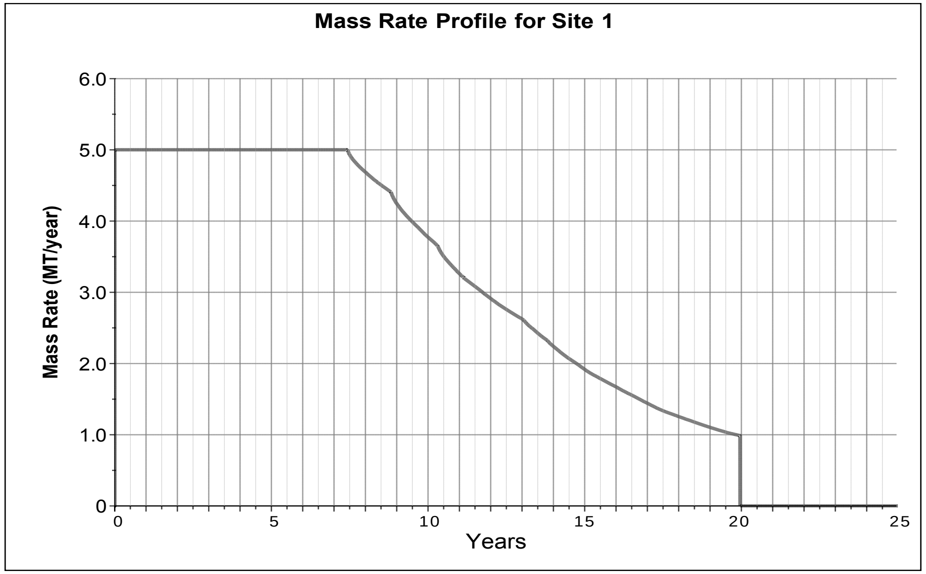

Figure 32 - CO_2 mass rate profile for Site 1

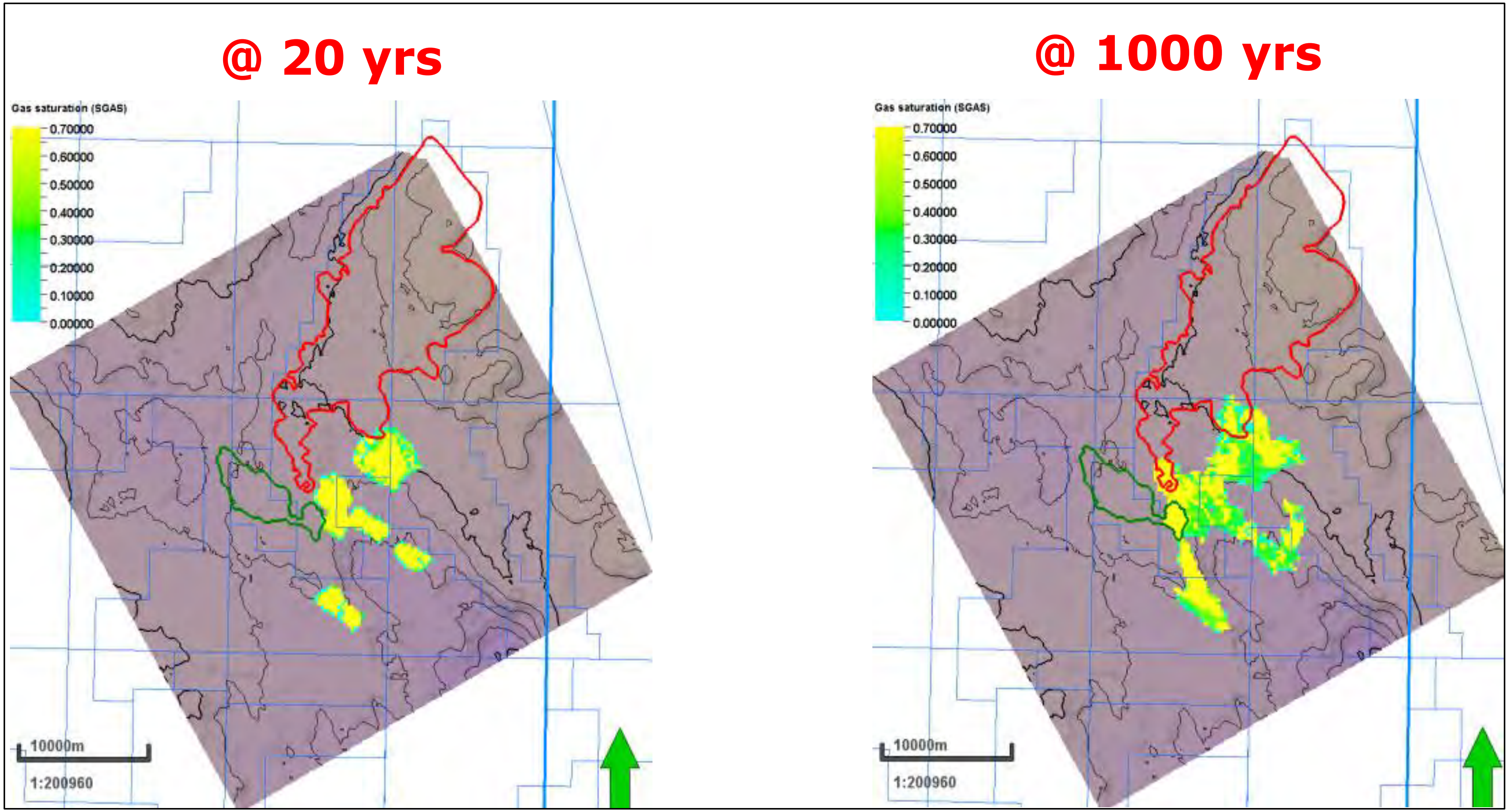

Figure 34 - CO_2 plume migration for Site 1

During injection the area pressure increases to the fracture pressure limit and equalises throughout the Site 1 area.

The plume at this time has not migrated into the Everest field region.

When injection stops the plume continues to migrate towards the Everest field but is controlled mainly by structural definition and rock properties as the Everest field pressure sink has been re-pressurised.

The plume migration after 1000 years is shown in Figure 34. In addition, the change in CO_2 concentration from end of injection to 1000 years shut-in is displayed in Figure 35.

After 1000 years the plume has still not migrated into the Everest field closure. The maximum velocities after 1000 years are < 1m/year suggesting that even if the CO_2 plume continued to move at that rate it would take between 5000 and 10,000 years to reach the crest of the Everest field structure. EU guidance requires that long term stability of the CO_2 plume within the storage complex is achieved for safe storage. In previous studies (Energy Technology Institute, 2011) this has been interpreted as the plume velocity being less than 10m/year and declining. Although the calculated velocities are low in this case, in the event that the CO_2 plume continues to migrate, it will migrate towards the Everest Field where it will be structurally trapped.

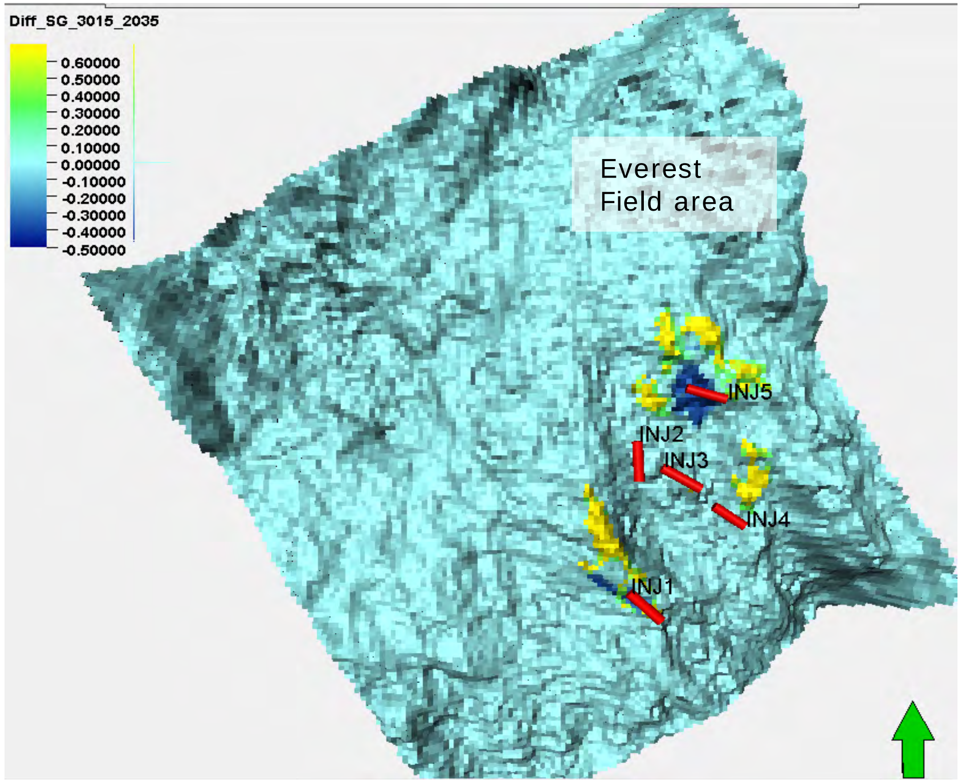

Figure 35 - Change in CO_2 concentration from end of injection to 1000 years shut-in for Site 1

12.0 Oilfield Site Reconsideration

Following the Stage Gate review in August 2015 and approval of the five sites for detailed study in WP5 a question was raised regarding the potential role of oilfield sites which were acknowledged as potentially high quality stores, but eliminated from further consideration in this study because of their EOR potential. An additional piece of work was requested to further inform this decision and specifically check to identify whether any of these sites might represent poor EOR candidates but high potential CO_2 storage sites. The work included two key steps:

1. Review the EOR inventory sites (those initially excluded EOR candidates) from the screening phase of WP3 and rank them according to their likely attractiveness as EOR developments. Then identify poor EOR development candidates from this list which might meet the storage site metrics of the rest of the project.
2. Identify and recommend a contingency Oil & Gas site which might be evaluated in the event that a suitable saline formation injection site cannot be identified in the Forties 5 aquifer.

The rationale behind this request was to ensure that the decision to exclude these sites due to their EOR potential did not inadvertently eliminate certain oilfields which may have excellent potential as CO_2 stores. For clarity, it is not the purpose of this scope to look at evaluating or optimising CO_2 storage in CO_2 enhanced oil recovery projects.

The fields identified as having good EOR potential in the Element Energy Report (Element Energy Ltd, 2012) were further screened to include UK- only fields, with no trans-border risks and <450km from the nearest beachhead.

A brief review of 18 oil fields identified as likely EOR candidates was completed using recovery factor as a proxy to estimate EOR potential, lower recovery factors indicating that a larger proportion of the resource will remain as an EOR target. Decline curve analysis was carried out for each of the remaining 18 fields using the DECC production data up to February 2015, and the fields were ranked according to their estimated ultimate recovery factor.

The top seven ranking fields (with the poorest EOR potential) were then screened for their CO_2 Storage Capacity and the five remaining fields with capacity >50MT (Beryl, Piper, Forties, Nelson and Fulmar) were assessed for their Qualification as a CO_2 Storage site using the IEAGHG minimum qualification criteria.

Of the five fields, only two sites have a reasonable prospect of being used as a CO_2 store, Fulmar and Piper. Fulmar was screened in WP3 and whilst it did not fail on any of the qualification criteria and made it into the “Qualified Inventory” of 37 sites, it did not reach the 20 on its own merit. Piper has excellent reservoir properties but significant challenges regarding legacy wells are anticipated.

The conclusion was to cease further due detailed diligence on these sites at this time. In the unlikely event that a suitable injection site could not be found in the Forties 5 open aquifer system then the Britannia Condensate Field will be the backup store. The rationale being that Britannia had performed well during the WP3 screening process and was only ranked lower than Bruce because of Britannia’s late COP. However. as a replacement for the Forties 5 aquifer Britannia creates a stronger portfolio than Bruce.

Further details are provided in Appendix 1.

13.0 Conclusions

General

- A comparison of five test injection sites has been completed over the Forties 5 unit to select the strongest candidate from which to initiate a development of the Forties open aquifer system.
- The potential exists to develop CO_2 storage projects at all five sites, although each has different challenges and advantages.
- There is extensive geological and geophysical data available across the Forties 5 unit area which enabled a representative static model build to be completed. In detail the Forties reservoir has a complex internal architecture which is challenging to capture at the detail described in individual oilfields where well density is much higher. Seismic attributes were helpful in building confidence around the main depositional trends.
- Other data from petroleum operators which is not routinely placed into the public domain such as reservoir pressure trends and individual well performance was largely unavailable to this study due to challenges linked with data access. Information such as depletion on the Everest gas field has relied on published papers and journals. This starts to present some challenges to reducing uncertainty in dynamic performance under injection to this study. In a commercial environment without the disclosure commitments of this project it is anticipated that such data access would be possible under appropriate confidentiality agreements.
- After reviewing the options, the site with the best combination of simple and robust containment with storage potential is Site 1, located in the East of the Forties aquifer just south of the Everest gas field. Whilst the volume injected into Site 1 (85MT) was not as good as the northern or western sites because of the reservoir quality variation, further optimization of well locations is expected to improve this performance. Site 1 has robust containment characteristics with fewer caprock complexities associated with overlying sandy formations. Site 1 also benefits from having the structural closure of the Everest depleted gas field as a secondary trapping mechanism, in the unlikely event that the CO_2 plume moves significantly faster than predicted.

Injection Performance

- The 3D dynamic model built over the entire Forties aquifer area provided an effective rapid assessment tool to compare the injection performance of each potential CO_2 storage sites could be assessed. Streamline simulation on a relatively coarse gridded model ensured run times were manageable.
- Four of the five sites performed well under dynamic simulation testing, achieving initial target well injection rates. The CO_2 plume migration varied for each site and was dependent on the structural definition and rock properties distribution. The injection performance of Site 2 in the southern part of the Forties 5 unit was restricted by poorer reservoir quality in that area. As a consequence of this Site 2 is not recommended for further detailed study at this time.
- The simulation was set up with equivalent injection targets and constraints for each site. The target injection rate was set at 1MT/year

per well, for a 5 well development injecting for 50 years. This equates to a total potential injected volume of 250MT per site. The actual injected volume per site ranged from 33MT to 188MT, less than the potential as all sites reached the BHP limit during the 50 years of injection. These injected volumes are useful comparators, but should not be considered as estimated capacities at this stage

Containment

- Injection performance and capacity alone are insufficient for site selection and must be balanced with a careful consideration of containment risk. The top seal for the Forties sand is provided by the overlying mudstones of the Sele Formation, which provide the proven seal for hydrocarbon fields within the main area of the Forties fan. As a result, geological containment across the main Forties fan area is seen as generally low risk.
- Containment along the eastern edge of the main fan is provided by the sands thinning or pinching out, stratigraphically trapped by the surrounding mudstones (Site 1 and Site 2)
- In the west and north there are no hydrocarbon accumulations in the Forties reservoir. Furthermore, hydrocarbon shows in shallower horizons indicate the potential for migration paths from the Forties sand fairway upwards into stratigraphically younger secondary reservoirs that elevate the complexity of the containment architecture and the geological containment risk in these areas. Whilst these point to potential enhanced secondary storage capacity, it results in a more complex containment picture (Sites 3, 4 and 5).
- The Forties 'open aquifer' is actually a complex mix of trapping mechanisms. These include:
    - Buoyant Trapping (both stratigraphic and structural)
    - Residual Trapping
    - Solution Trapping
    - Low Velocity Trapping (where CO_2 plume velocities are so low that containment within a storage complex can be assured for a minimum of 10,000 years.

Validation of Site 1 Injection Performance

- Validation of the dynamic assessment of Site 1 using conventional simulator was a useful step to confirm performance of streamline simulation as a useful tool for CO_2 Storage screening in open aquifer systems. A sector model was extracted from the full Forties aquifer model over Site 1 and the model was used to assess the migration of the CO_2 plume 1000 years after injection ceased. Injectivity was in agreement with the streamline simulation results. The CO_2 plume migrated towards the Everest field and just reached the edge of the field after 1000 years. At this time the plume velocity was less than 1m/year. Further subsurface sensitivities will be carried out in the detailed modelling in WP5 but if the plume migrates further and faster than expected it will migrate to the Everest field where it will be structurally trapped.

Oilfield Site Reconsideration

- A brief review of 18 oil fields identified as likely EOR candidates suggested 7 fields as less promising EOR candidates because of their high recovery factors under waterflood. These sites might therefore be more likely to be available for CO_2 storage. Two of these sites had been assessed and screened out during WP3 on the basis of their poor storage attributes.

- Five remaining sites were added to the Qualified Inventory from WP3 and the TOPSIS ranking was repeated to compare their performance in matching the project objectives alongside the other storage units. The most promising storage candidate oilfields were Fulmar and Forties (oil field) however none of the 5 petroleum sites appeared in the top twenty ranked sites. As a result, none of these sites performed well enough to merit a place in the Select Inventory.
- It was concluded not to progress the analysis any further, but retain the Britannia gas condensate field as a potential reserve site for the Forties 5 unit.

14.0 Recommendations

- It is recommended that Site 1 (Eastern site) is taken forward to WP5 for a more detailed evaluation as it is the site with the least risk of loss of geological containment while still meeting the injection target.
- Well placement and design will have a significant impact on injectivity and capacity for this site. One case was considered for the screening study. The well optimization will be carried out in more detail in WP5.
- A more detailed model will be built for use in WP5. The subsurface uncertainty associated with top structure and rock properties will be assessed as part of the workflow. The connectivity between the aquifer and Everest field will be more fully evaluated.
- The loss of containment in existing and legacy wells has not been assessed in this study. Further work will be carried out in WP5 to assess well conditions particularly for the Everest and Huntington fields, the producing fields within the selected site.
- The depletion in the Everest field was captured as a pressure sink in the screening study but the hydrocarbon gas and associated compressibility effects have not been accounted for. This will be incorporated in the more detailed modelling study.
- It is recommended that further work on EOR candidates is now ceased because they have been unable to make the top 20 rankings of the Select Inventory, even after reconsidering their availability for CO_2 storage.
- Future studies should consider a more robust and sophisticated approach to determining the EOR potential of oil fields which accounts for the incremental planned ultimate recovery under CO_2 flooding vs existing waterflood operations, the cost of essential topside and well modifications or replacement of facilities and the full chain emissions footprint (and therefore cost) of EOR operations on a TCO_2 per MWH (effective) basis.

15.0 References

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Appendix 1 – WP5 Review of CO_2 EOR Sites for CO_2 Storage

Executive Summary

Following the Stage Gate review in August 2015 and approval of the five sites for detailed study in WP5 a question was raised regarding the potential role of oilfield sites which were acknowledged as potentially high quality stores, but eliminated from further consideration in this study because of their EOR potential. An additional piece of work was requested to further inform this decision and specifically check to identify whether any of these sites might represent poor EOR candidates but high potential CO_2 storage sites. The work included two key steps:-

1. Review the EOR inventory sites (those initially excluded EOR candidates) from the screening phase of WP3 and rank them according to their likely attractiveness as EOR developments. Then identify poor EOR development candidates from this list which might meet the storage site metrics of the rest of the project.
2. Identify and recommend a contingency Oil & Gas site which might be evaluated in the event that a suitable saline formation injection site cannot be identified in the Forties 5 aquifer.

The rationale behind this request was to ensure that the decision to exclude these sites due to their EOR potential did not inadvertently eliminate certain oilfields which may have excellent potential as CO_2 stores. For clarity, it is not the purpose of this scope to look at evaluating or optimising CO_2 storage in CO_2 enhanced oil recovery projects.

The fields identified as having good EOR potential in the Element Energy Report (Element Energy Ltd, 2012) were further screened to include UK- only fields, with no trans-border risks and <450km from the nearest beachhead.

Simple decline curve analysis was carried out for each of the remaining 18 fields using the DECC production data up to February 2015, and the fields were ranked according to their estimated ultimate recovery factor. This is a proxy for their EOR potential; those with an ultimate recovery factor of >60% were considered to be the poorer EOR targets.

The top seven ranking fields (with the poorest EOR potential) were then screened for their CO_2 Storage Capacity and the five remaining fields with capacity >50MT (Beryl, Piper, Forties, Nelson and Fulmar) were assessed for their Qualification as a CO_2 Storage site using the IEAGHG minimum qualification criteria.

Of the five fields, only two sites were identified as having a reasonable prospect of being used as a CO_2 store, these were Fulmar and Piper. Fulmar was already screened in WP3 and although it did not fail on any of the qualification criteria and made it into the “Qualified Inventory” of 37 sites, it did not reach the 20 on its own merit. Piper has excellent reservoir properties but significant challenges regarding legacy wells are anticipated.

As a result, it was concluded not to complete further due detailed diligence on these sites at this time. In the unlikely event that a suitable injection candidate site could not be found in the Forties 5 Open aquifer system then it was concluded to hold the Britannia Condensate Field as a backup store as this was an oil and gas field in the Central North Sea that performed well during the WP3 screening process.

Objectives

The objectives for this additional piece of work were two-fold:

1. Review the initially excluded EOR candidate sites from the screening phase of WP3 and rank them according to their likely attractiveness as an EOR development. Then identify an unattractive EOR development candidate which might meet the storage site metrics of the rest of the project.
2. Identify a contingency site to be evaluated in case a suitable injection site cannot be identified in the Forties 5 aquifer.

The rationale behind this addendum to WP4 is to ensure that the decision to exclude these sites due to their EOR potential did not inadvertently eliminate certain oilfields which may have excellent potential as CO_2 stores.

If a suitable "least prospective for EOR but good CO_2 storage" site was identified, a decision would be made whether there was any value in conducting due diligence on the site using the same methodology as for the Top 20 sites (described in detail within Deliverable 05, the WP4 report).

If the value of due diligence was questionable then another store would be held as contingency.

Methodology

The report, Economic impacts of CO_2 enhanced oil recovery for Scotland (Element Energy Ltd, 2012), suggests the most suitable fields for CO_2 -EOR within the UK and Norway. These were used as a starting point and an initial high-level screening was carried out to select those fields that met the following criteria:

- UK only with no risk of trans border issues
- Less than 450km to nearest beachhead

18 fields remained, which all met the project COP (without EOR) criterion of <2030.

EOR Potential

For an oil field to present potential as a CO_2 EOR development it must have the following characteristics:-

1. It should have demonstrated performance under primary or secondary recovery that suggests that a large proportion of the reservoir volume can be connected with a reasonable well infrastructure. If a field has performed well under waterflood, this will almost certainly be the case.
2. The reservoir pressure should be high enough such that injected CO2 is miscible with the oil. The CO2 EOR process relies heavily upon this miscibility process for its effectiveness. Above the miscibility pressures CO2 causes residual oil to expand on contact as the oil vaporises into the dense phase CO2 and CO2 dissolves into the oil.
3. There should be a significant difference in the residual oil saturation values after CO_2 flood and water flood. A water flood which has recovered 70% of the STOIIP might have a residual oil saturation after waterflood of only 15% on a core plug scale (with 90% vertical sweep efficiency and 90% areal sweep efficiency). The same core plug after CO2 flooding might have a residual oil saturation of perhaps 10%. With the same sweep efficiency this would recover an additional 4% of STOIIP for a full field CO2 EOR development (Incremental recovery factor). Clearly in poorer quality reservoirs where residual oil levels are higher, there is more opportunity for CO_2 EOR effectiveness and incremental recovery factors can exceed 25% in some onshore US projects.
4. Finally, offshore CO2 EOR requires scale to stand a chance of being commercially effective. This requires large EOR target volumes, many wells and a front loaded and significant CO2 supply of at least 2MT/yr. All the fields considered here are of appropriate scale to be of interest for CO2 EOR given the right economic conditions.

Analysis

Analysis on the 18 fields was carried out to understand what constituted a good and poor EOR candidate. This analysis included:

- Assessment of current projected ultimate recovery without EOR, based on DECC production data and using simple decline curve analysis
- Assessment of ultimate recovery factor of each field using the projected ultimate recovery and Stock Tank Oil Initially in Place (STOIIP) from public sources

- Ranking of fields on their likely EOR potential, using the ultimate recovery factor. Any field with an ultimate recovery factor of <60% could be considered more likely as an EOR target.

A plot of STOIIP vs ultimate recovery factor is shown in Figure 36 for the 18 fields.

A summary of the data for this plot can be found in Table 5 in the Appendix.

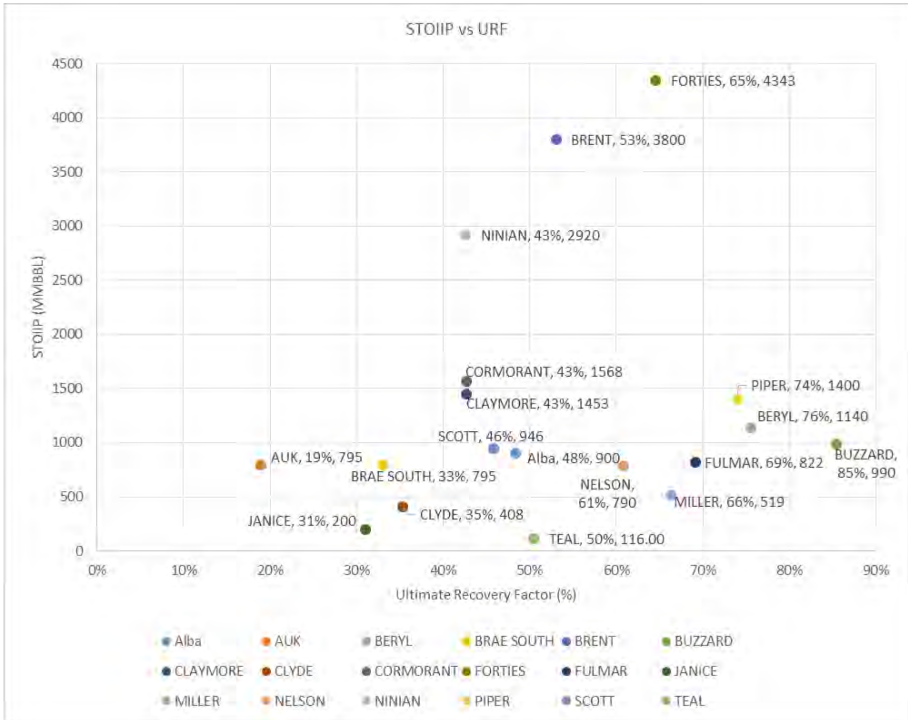

Figure 36 – Stock Tank Oil Initially in Place vs ultimate recovery factor for 18 fields

Seven fields had an ultimate recovery factor of >60% and so were considered to be poorer EOR targets based on this initial screening cut-off:

1. BERYL
2. PIPER
3. FORTIES
4. BUZZARD
5. NELSON
6. FULMAR
7. MILLER

These seven fields were then assessed for their suitability as a CO_2 store. Of these, Buzzard and Miller were both screened out as their theoretical CO_2 Storage (only) capacity was less than 50MT.

The five remaining sites Beryl, Piper, Forties, Nelson and Fulmar were then assessed for their CO_2 Storage Site Qualification, summarised in the table in Results section.

Results

The CO_2 Storage Site Qualification of the five sites are summarised below.

Field	Ultimate Recovery Factor (%)	STOIIP (MMBBL)	Estimated remaining oil in place at COP (MMBBL)	Capacity in CO2 Stored (MT)	# Wells	Permeability (mD)	Thickness (m)	Porosity (%)	Distance to Beachhead (km)	Additional recovery factor - Feb '15 to COP (%)	Comments (benefits and challenges)
Beryl	76	1140	274	145	213	350	150.00	17%	437	2%	Site OK from a capacity and reservoir quality perspective although has a challenging complex Jurassic reservoir. Due to this, high recovery factor may also indicate uncertainty in the STOIIP value. Site furthest away at almost 450km from St Fergus. .
Piper	74	1400	364	123	92	4000	97.00	24%	158	0%	Site OK from a capacity and reservoir quality perspective. Significant challenges with legacy wells.
Fulmar	69	822	255	53	51	500	365	23%	270	0%	Already screened in WP3. Made the top 37, but did not make the top 20 on its own merit.
Forties	65	4343	1520	312	373	700	353.87	27%	165	2%	Whilst the recovery factor is high at 65%, the volume or remaining oil representing an EOR target is high at over 1.5 billion barrels Therefore unlikely to be considered for CO_2 Storage only.
Nelson	61	790	308	68	82	216	78.33	23%	178	2%	Whilst Nelson is a lower relief structure than other fields, it still retains 790MMSTB of oil at the end of its life. Of the 5 fields listed here it may have the best EOR potential since almost 30% of the STOIIP will remain as an EOR target after waterflooding.

Table 4 – Summary of 5 fields to be considered as a CO_2 store. Comments highlight benefits and challenges of each site.

Of the fields in the table, those with the least EOR potential and reasonable prospects of being used as a CO_2 store are Fulmar and Piper.

These five fields were added to the “Qualified Inventory” of WP3 and the TOPSIS ranking performed again to check their performance. Of the five fields added from the “EOR Inventory” none appeared in the top twenty. The best performing fields were Forties and Fulmar.

Whilst five selected oilfields remaining targets are both good EOR and storage prospects they are not recommended for further consideration here because:-

- Beryl is challenging due to its distance to beachhead (almost 450km) and is also a Jurassic reservoir of high complexity.
- Forties could still be considered an EOR target due to its high STOIIP and volume of remaining oil after COP. To consider the depleted supergiant field as a CO_2 storage site without EOR does not stand up to serious scrutiny.
- Whilst Nelson is a lower relief structure than other fields, it still retains 790MMSTB of oil at the end of its life. Of the 5 fields listed here it may have the best EOR potential since almost 30% of the STOIIP will remain as an EOR target after waterflooding.
- The Fulmar field has already been screened in the WP3/WP4 scope. It was successful in meeting all the project and IEAGHG screening criteria and made t into the top 37 sites. It failed however to make the top 20 and was not considered further.
- Piper has excellent reservoir properties but there are likely to be significant challenges regarding legacy wells.

After review with ETI, the decision gate recommendation was that there was little value to this project in doing further due diligence on any of these oilfield options. Britannia Condensate Field should be kept as a backup store, as per the outcome of WP3.

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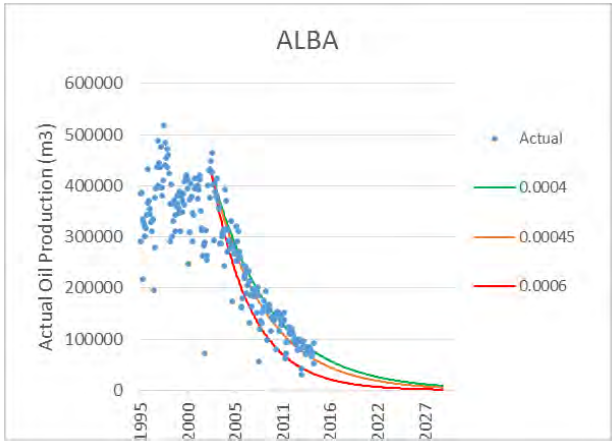
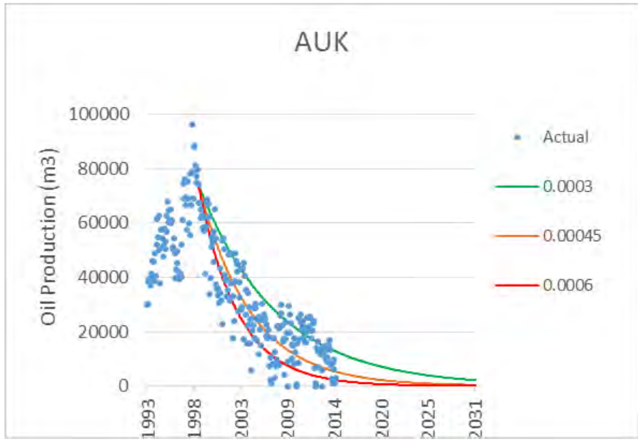
Appendix

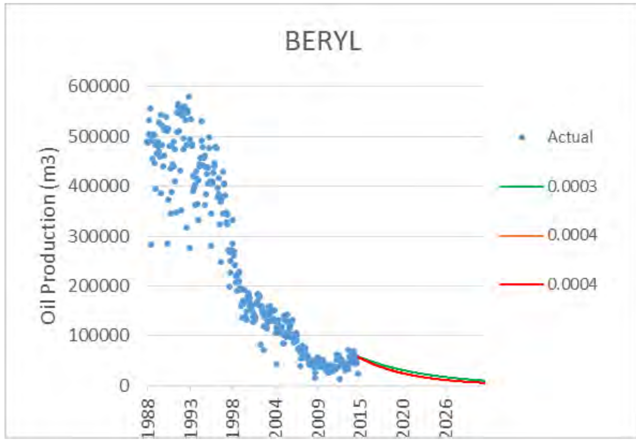
The figure below contains the results of the simple decline curve analysis for the 18 fields. Actual historical production data to February 2015, taken from DECC website, are shown in the blue points. The three curves correspond to different decline curve coefficients and have been determined based on their best-fit to the actual data.

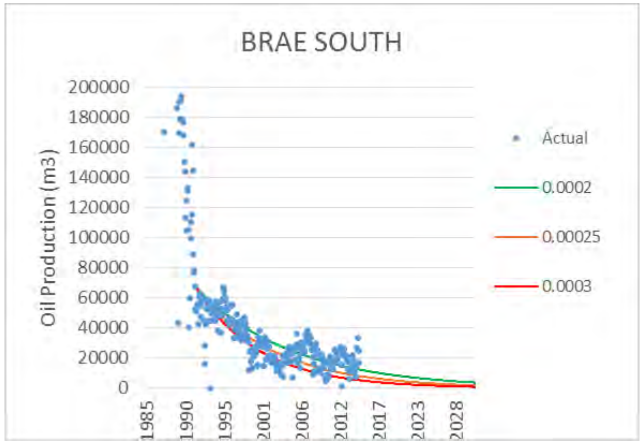
Note that:

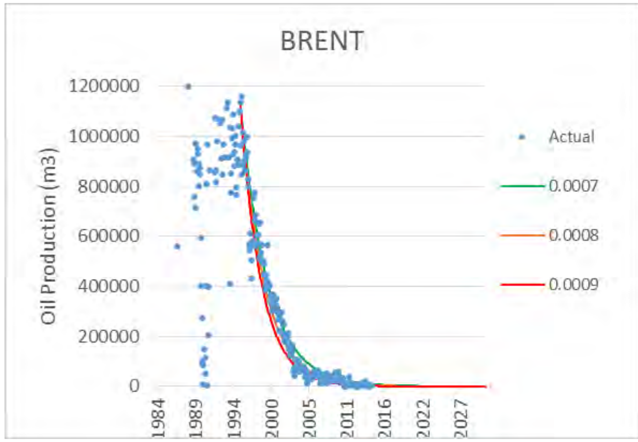
- Any analysis on Buzzard is likely to be erroneous as the data does not indicate if the field is in decline.
- Miller ceased production in 2008 and so no forecasting is required.

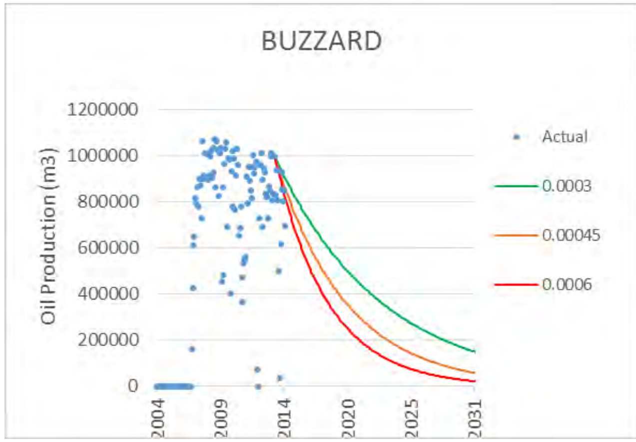

ALBA
Actual Oil Production (m3)
Actual
0.0004
0.00045
0.0006

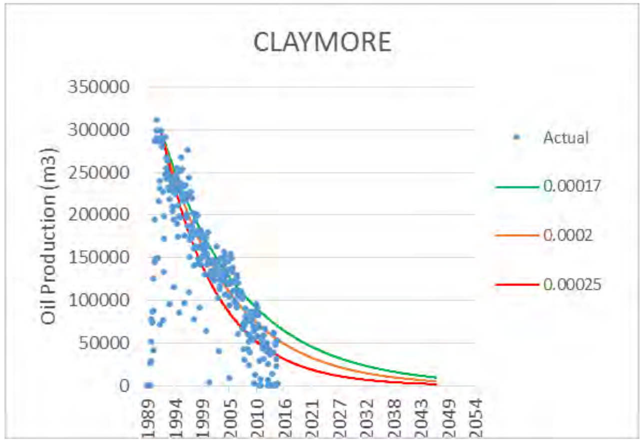

AUK
Oil Production (m3)
Actual
0.0003
0.00045
0.0006

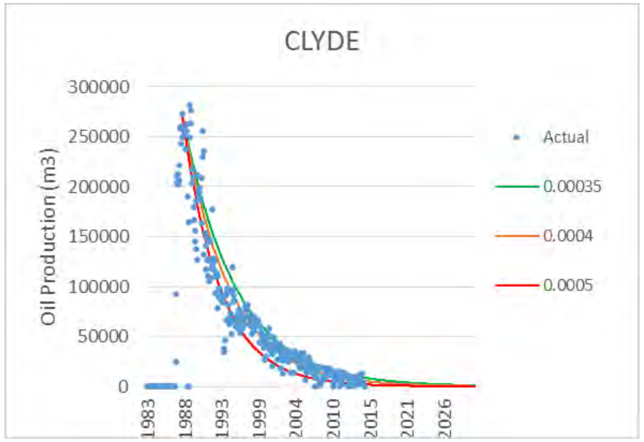

BERYL
Oil Production (m3)
Actual
0.0003
0.0004
0.0004

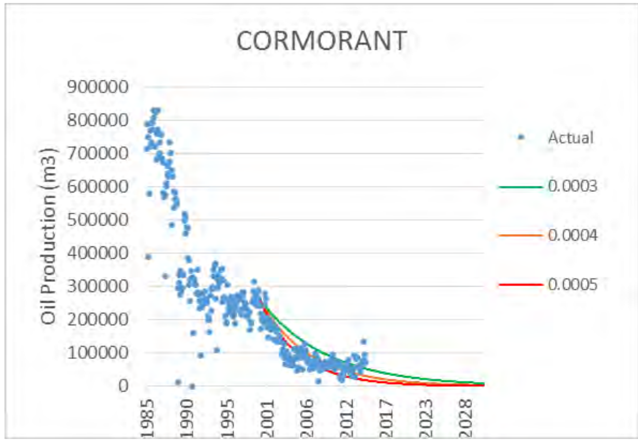

BRAE SOUTH
Oil Production (m3)
Actual
0.0002
0.00025
0.0003

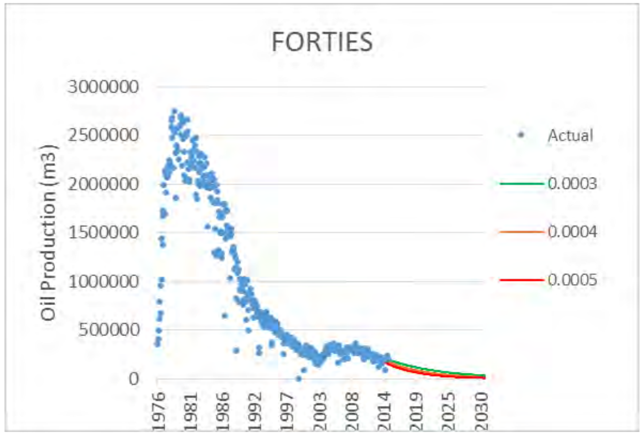

BRENT
Oil Production (m3)
Actual
0.0007
0.0008
0.0009

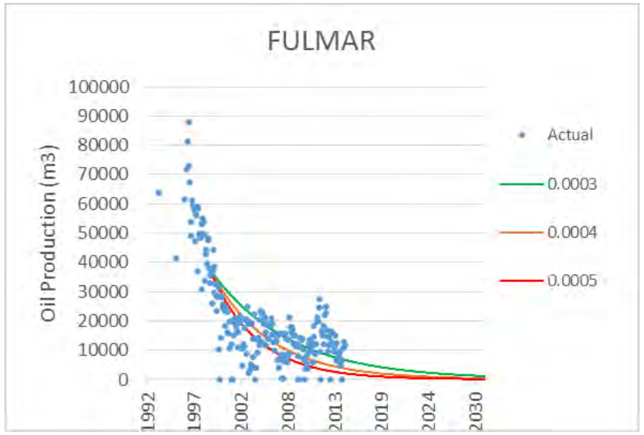

BUZZARD
Oil Production (m3)
Actual
0.0003
0.00045
0.0006

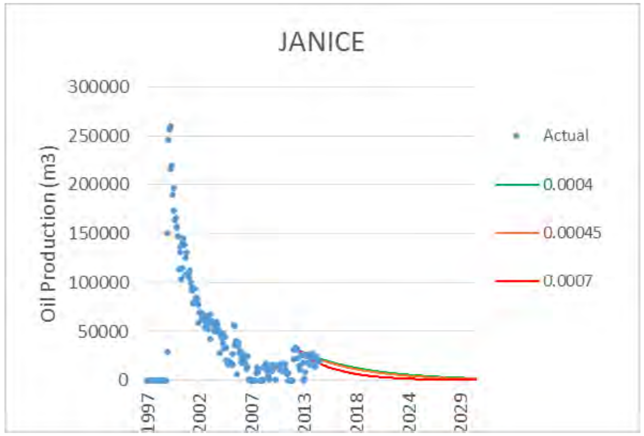

CLAYMORE
Oil Production (m3)
Actual
0.00017
0.0002
0.00025


CLYDE
Oil Production (m3)
Actual
0.00035
0.0004
0.0005


CORMORANT
Oil Production (m3)
Actual
0.0003
0.0004
0.0005


FORTIES
Oil Production (m3)
Actual
0.0003
0.0004
0.0005


FULMAR
Oil Production (m3)
Actual
0.0003
0.0004
0.0005


JANICE
Oil Production (m3)
Actual
0.0004
0.00045
0.0007

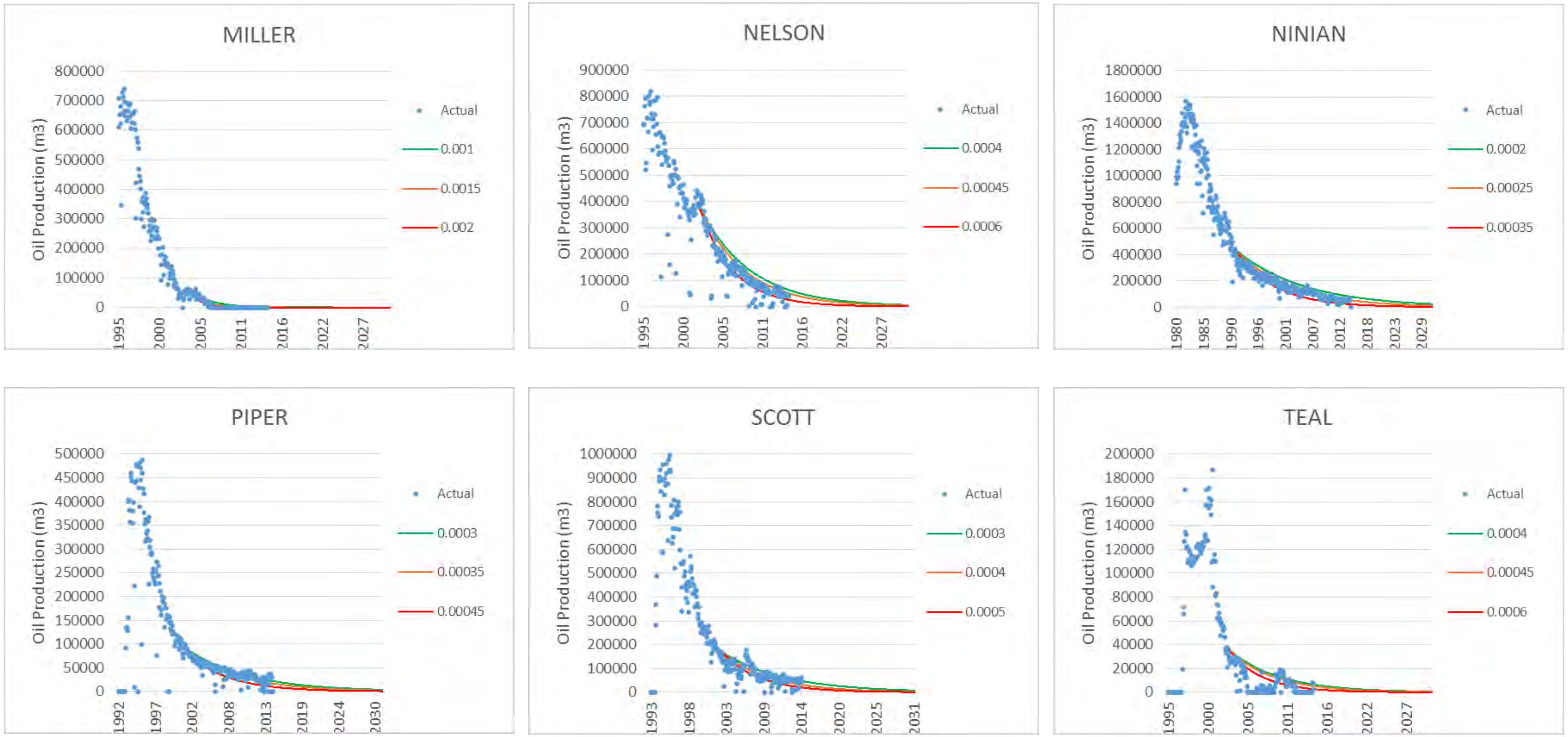


Figure 37 – Decline curve analysis on 18 selected EOR candidate fields

Field	1) Preliminary Screening			2) Poor EOR Candidate Screening		3) CO_2 Storage Site Qualification Screening							
	UK only ?	Distance to Beachhead <450km?	COP (<2030)	Ultimate Recovery Factor (>60% to be considered)	STOIIP (MMBBL)	Capacity in CO2 Stored (MT)	Wells (#)	Permeability (mD)	Thickness (m)	Porosity	Analysis and screening already done in WP3?	Additional recovery factor (Feb '15 to COP)	STOIIP Reference
ALBA	y	y	2028	48%	900						n	3%	2
AUK	y	y	2018	19%	795						y	0%	3
BERYL	y	y	2026	76%	1140	145	213	350	150.00	0.17	n	2%	4
BRAE SOUTH	y	y	2019	33%	795						y	0%	5
BRENT	y	y	2016	53%	3800						n	0%	6
BUZZARD	y	y	2027	85%	990	13					y	35%	7
CLAYMORE	y	y	2028	43%	1452.9						y	2%	8
CLYDE	y	y	2026	35%	408						y	1%	9
CORMORANT	y	y	2023	43%	1568						y	1%	10
DUNLIN	y	n	n/a	n/a	827						n	n/a	11
FORTIES	y	y	2027	65%	4343	312	373	700	353.87	0.27	n	2%	12
FULMAR	y	y	2026	69%	822	53	51	500	365	0.23	y	0%	13
JANICE	y	y	2018	31%	200						n	2%	14
MILLER	y	y	2007	66%	519	5					y	0%	15
NELSON	y	y	2025	61%	790	68	82	216	78.33	0.23	n	2%	16
NINIAN	y	y	2027	43%	2920						y	1%	17

Field	1) Preliminary Screening			2) Poor EOR Candidate Screening		3) CO_2 Storage Site Qualification Screening							
	UK only ?	Distance to Beachhead <450km?	COP (<2030)	Ultimate Recovery Factor (>60% to be considered)	STOIIP (MMBBL)	Capacity in CO2 Stored (MT)	Wells (#)	Permeability (mD)	Thickness (m)	Porosity	Analysis and screening already done in WP3?	Additional recovery factor (Feb '15 to COP)	STOIIP Reference
PIPER	y	y	2020	74%	1400	123	92	4000	97.00	0.24	n	0%	18
SCOTT	y	y	2021	46%	946						y	1%	19
TEAL	y	y	2023	60%	116	Not in CO2 Stored but small					n	2%	30
THISTLE	y	n	n/a	n/a	824						y	n/a	21

Table 5 – 20 UK fields from Element Energy Report and screening down to 5 most suitable for CO_2 Storage and least likely for EOR.

Appendix 2 – Record of Advisors Meeting

Date: 6/10/2015

Venue: Church House Conference Centre

Attendees

In person: A Green (ETI), D Gammer (ETI), B Senior (CCS Solutions), S Cawley (BP), A James (PBD), S Murphy (PBD)

By phone: E Halland (NPD), B Court (GCCSI), S McCollough (AWT), K Johnson (AWT), D Hardy (AWT)

Material Provided

D07 10113ETIS WP5 Report - Review of Forties 5 Aquifer Storage Unit Selection v1.2 (Word)

SUKSAP Forties Advisors 151007 (Powerpoint)

Discussion Highlights

BS. Lateral Containment is clearly important & should be highlighted in the report.

SC. Please include a common risk segment map to help clarify the rationale for selecting Location 1. Request endorsed by BS.

EH. Are there many faults above the Diapirs? KJ. Faults do exist but are generally minor & not located near to the top of the salt diapirs – there is no Forties sand above these features

BS. Might a bias against oil fields may have been introduced because areas of high well density have been avoided? Team. No intentional bias, oil fields were screened using the same criteria as other potential storage units, well density was one aspect that was considered amongst several. Oil fields tended to rank lower for a range of reasons including small size, distant location, well density, likelihood of EOR etc.

EH. Why has Location 4 been screened out? SMcC. The plume was more extensive & concerns about containment risk to the West.

SC. Could Location 4 be optimised to minimise leakage risk? Team. Yes, to a degree, all sites would benefit from optimisation however the overriding concern is containment risk for Location 4.

SC. A depth map with the seismic amplitude drape & showing the hydrocarbon fields in the Forties would be a nice supplement to the time map. KJ. Yes, this could be done but would be more useful in the more detailed work that will follow.

AG. It looks as if containment has been ranked more favourably than reservoir properties and so Location ranks highest. Team. Yes.

BC. What is the rationale behind the initial site selection and the well placement? Team. Selection based around understanding of regional geology and its influence on containment, rock property trends & their impact on injection performance. Wells were placed in structural lows to maximise vertical migration path.

BS. What is meant by “low migration velocity trapping” & where has the concept originated? AJ. The term was used within the UKSAP project. Low velocity trapping describes any CO_2 not already trapped structurally, residually or by dissolution that may be still moving but at a velocity which will contain CO_2 within the Storage Complex over several thousand years.

Actions

1. Develop a “common risk segment” map & include in the report.
2. Comment on the potential bias against large oil fields that is introduced by EOR potential and well density.
3. Present site 4 as potentially very good and worthy of further consideration.
4. Need some careful pithy wording around the role of open aquifers and the management of expectations.
5. Qualify and explain the different types of trapping mechanism, including “low velocity trapping”.