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Impact of sub seismic heterogeneity on CO_2 injectivity

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Abstract

The geometry of the depositional facies and the sandbody continuity in turbidite and fluvial reservoirs controls the stratigraphic heterogeneity, and therefore controls permeability structure. This has implications for CO_2 injectivity from localized pressure build up around injection wells, and migration pathways due to dispersive flow, which results in CO_2 contacting more of the rock volume than would be the case in a homogenous system.

This reservoir simulation study is an investigation of the impact of geological heterogeneity in channelized sandstone formations on pressure buildup during CO_2 injection. Four geological models of fluvial and turbidite depositional systems were constructed, typical of those which occur in the Southern North Sea and the Central North Sea regions. Model grid cells were reduced to less than 10 m in places to properly represent the individual channel structures and 2 m near wellbores. This presented a challenge for simulation to capture the impact of injectivity accurately with high resolution for a basin-scale model. Sensitivity studies were carried out in two groups with different net to gross (NTG) ratios and mean permeabilities.

The simulation results showed that connectivity to sand-body volumes, through the individual fluvial channel interconnections, may be poor, and so CO_2 does not readily access the entire volume. Furthermore, if the mean permeability is less than 10 mD, only NTG, or the volume fraction of high permeability channels, affects the injectivity; the facies type, i.e. fluvial or turbidite, does not affect strongly the minimum injectivity for all models with 80% sand.

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Keywords: CO_2 storage, Injectivity, Heterogeneity

1. Introduction

The geometry of the depositional facies and the sandbody continuity controls the stratigraphic heterogeneity, and therefore controls permeability structure, reservoir connectivity, which in turn, has implications for CO_2 injectivity and migration pathways [1, 2]. Heterogeneity can lead to dispersive flows, leading to the delivery of CO_2 to a wider range of the reservoir rock, and enhance the storage capacity by increasing the sweep efficiency. Conversely, heterogeneity can also lead to a lack of connectivity between higher permeability sand-bodies [1], which in turn can be a major cause of localized pressure build-up around injection wells [3].

The CO_2 storage capacity for a potential storage site is often assessed by using reservoir simulation at the basin scale. The permeability heterogeneity existing at a scale around 1 m to 10 m through features including alluvial channels and small-scale

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faulting could be described from data such as surface exposures, core and from dredging of sandstone sedimentary features, and is included in a geological model which may contain tens of millions of grid cells. Due to limitation in computational capacity, geological structures smaller than 100s of meters are typically either not represented or upscaled.

The aim of the study is to investigate the impact of geological heterogeneity in channelized sandstone formations on pressure buildup during CO_2 injection by using fine scale (less than 10 m) dynamic modelling. The conceptual model of the study is based on the Forties geological model which was used in the Energy Technologies Institute (ETI) UKSAP project as an open exemplar of an open aquifer to assess storage efficiency and capacity [3]. This model is hereafter referred to as the "ETI model" in the following sections.

2. Conceptual model

The simplest method to study the impact of stratigraphic features on injectivity of CO_2 is by using a conceptual model in which certain properties can be varied systematically and the rest of the parameters remain unchanged. It is assumed that those variables can be decoupled from the constant parameters in the simulations. The constructed geological models consist of fluvial or turbidite depositional systems, typical of those which occur in the Southern North Sea (Triassic, Bunter fluvial) and Central North Sea regions. These are largely comprised of stochastic sand channel networks contained within a low permeability shale matrix. The geological parameters of interest in the sensitivity study are facies type, NTG, and the mean of permeability of the aquifer.

The Forties Sandstone Member of the Sele Formation turbidites is in the Central North Sea. It is widely recognised as a formation with CO_2 storage potential that may be accessible from the Central North Sea infrastructure network. A section of this formation between the Nelson and Phyllis fields was chosen as an exemplar to assess storage efficiency and capacity. The potential licensable open aquifer storage unit covers an area of 100 km × 100 km as shown in Figure 1. The model used in UKSAP was 21.4 km × 36.0 km in extent and is shown by a black rectangle, orientated northwest to southeast, and spans several blocks in Quadrant 22 of the Central North Sea with an average aquifer thickness of 170 m. In this study, the model shown in the red rectangle covers an area of 13.0 km × 12.6 km was used to investigate the role of channel structure on pressure buildup due to CO_2 injection and to compare with the results from ETI model.

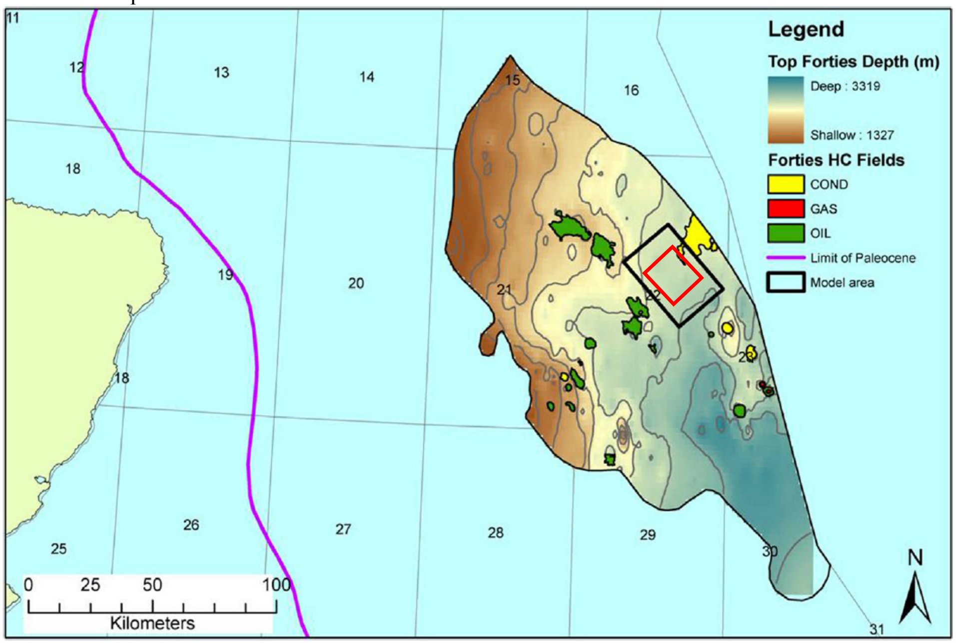


Figure 1 Location of the Forties Sandstone member, the Forties geological model for UKSAP (black rectangle), and the model used in the project (red rectangle), after Goater, et al. 2013 [3].

Geological models of sub 100 m structures have been developed based on a conceptual understanding of the depositional environment of the Forties Sandstone. Two typical depositional environments, one a fluvial and the other a turbidite depositional system, are chosen as conceptual models, so as to represent the outcome of two significant depositional processes. Figure 2 represents the more updip, channelized reservoirs, which are present in fields such as Forties and Nelson [4]. As shown in Figure 2, the dominant features are major channels containing the best reservoir quality sand. Therefore, fluid flow in the channels, which may be lined by shale drapes that impede flow across the channels, is relatively straightforward. In addition, CO_2 may be trapped in facies of lesser reservoir quality such as channel margin, overbank and interchannel deposits.

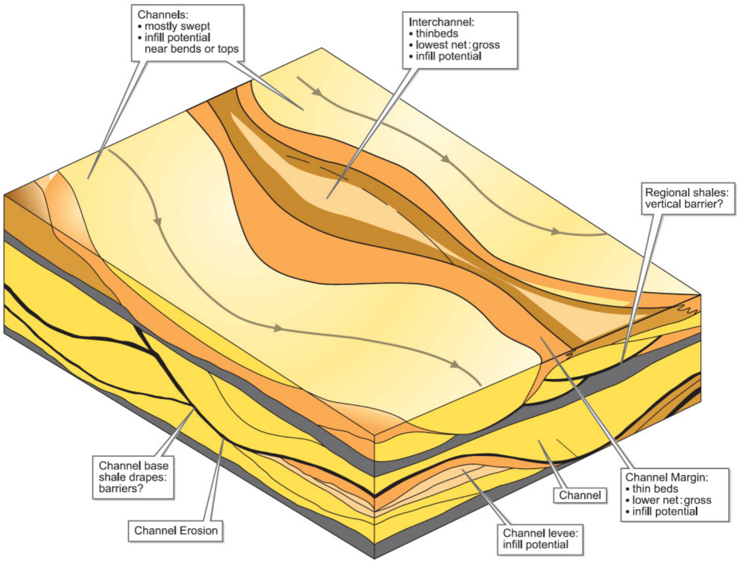


Figure 2 Forties reservoir structure showing channels, channel margin, channel levee, and shale (after Hempton et al., [4]).

Turbidite reservoirs are usually considered less complex than other types of reservoirs [5], but an uncertainty in predicting flow in turbidite reservoirs is often caused by mudstone drapes on erosional channel walls. Oil recovery factors from fluvial reservoirs are generally low. The impact of facies heterogeneity on hydrocarbon recovery, by analogy, will also affect CO_2 injectivity. Large-scale heterogeneity in fluvial channel-fill sandstones is a function of the connectivity of large-scale, channel-fill, and overbank deposits [1].

The main issue related to maximizing well injectivity is to recognize the occurrence of shale and stratigraphic variations in NTG ratios as it is a key characteristic to relate the facies model with reservoir connectivity [6]. Injectivity is affected both by the volume fraction of high permeability channels (ratio of shale to sand) in the formation and their spatial connectivity to the CO_2 injection wells. Sensitivity studies were carried out in two groups, one with different NTG ratios, and the other with different contrasts of low and high permeabilities. In the area studied, the range of NTG is between 65% and 80% [4].

Four models were developed; two for a fluvial system, F65 and F80 (Figure 3a and 3c), and two for a turbidite system, T80 and T80s (Figure 3b and 3d), in which the number shows the NTG value and the initial letter shows the sedimentary system in the model. The fluvial models created in this project used exactly the same structure as the ETI model, but had narrower channels representative of a fluvial system, and NTG of 65% and 80%. Within the two turbidite models, Model T80 inherited geophysical data from the ETI study, i.e. it is another realization of the model with a refined geological model grid size of 200 m x 200 m. In Model T80S, the facies model and fluid properties were generated by downscaling from the ETI model to generate a similar but fine model (50m x 50m). The latter model employed a channel pattern which was very similar to the original ETI model so as to help ensure that differences in model performance were only due to the refining of the grid, so that the model can be compared with other models.

The detailed channel structures for both environments were constructed using the object modelling facility in Petrel. Firstly, a static Petrel sub-model was extracted from the ETI Forties Model and was developed with a binary Fluvial-Channel Facies system. Two facies bodies were defined using fluvial channels with different layout parameters in the F65 base case. The maximum correlation length in the x and y directions is in 1000s of meters, and of the z direction is less than 12 meters, which is the thickness of two layers. The width to thickness ration is between 8 and 50. For the turbidite model only one channel body was defined with the mean width of 500 m and the thickness of 8 to 12 m. Therefore, the properties of sand channel for both fluvial and tubidite models are more heterogeneous in the vertical direction than in the horizontal direction.

The porosity and permeability of the shale are assumed uniform at a constant value of 0.1 (fraction) and 0.00001 mD, respectively. In the area studied, the highest sandstone average permeability was found near the Forties Field at about 700 mD.

Near the Nelson Field, it averages 300 mD and further to the south it decreases to an average of 80 mD near the Montrose Field [4]. Sequential Gaussian simulation was then used to generate the distribution of permeabilities within the sand bodies assuming a spherical variogram type.

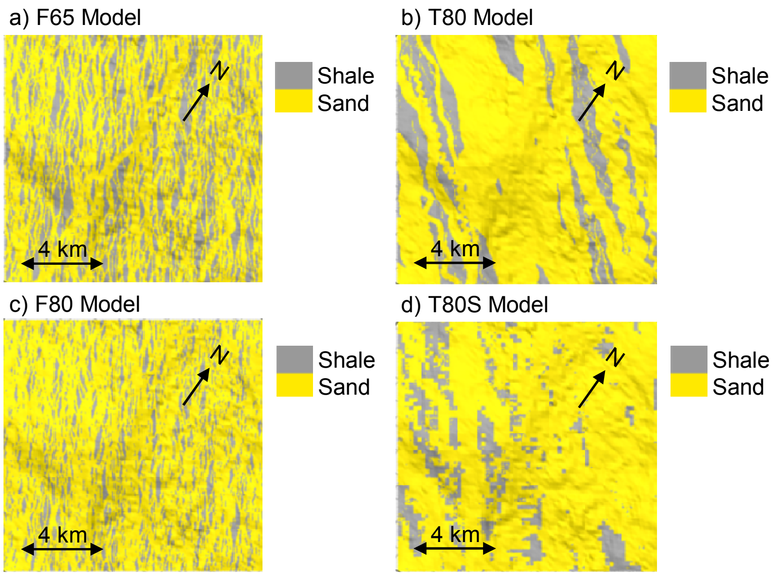


Figure 3 Facies models used in the sensitivity study

Porosity and permeability distributions of the sand bodies were generated using the mean and standard deviation from the original Forties model and the facies specification in the Petrel model. Additional information from upscaled well log data was also incorporated. This led a to a base case with a mean porosity of 0.2 (fraction) and a mean permeability of 100 mD. The stochastic realizations further assumed that log permeability is linearly correlated to the porosity, and the permeability distribution was generated from the porosity distribution using a co-located Co-kriging algorithm. In the sensitivity study, the mean permeability of the sand was set first to 10 mD, and then to 1000 mD, whereas the permeability of the shale was unchanged.

3. Numerical model development

The size of grid was chosen fine enough to represent reservoir heterogeneity. To cope with the scale of the wavelength and the width of the channels, the numerical model grid resolution has to be set to an order of 10s of meters. The ECLIPSE model has dimensions 13,050 m × 12,600 m × 170 m, and initially discretised into 1,973,000 cells, with 261 × 252 × 30 cells in the x, y and z directions, respectively. The size of each cell laterally is 50 m × 50 m and the thickness of each cell is between 4.6 m and 7.0 m to represent different units with channel-fill sandstone vertically.

To reduce the error induced by grid resolution on the well bottom hole pressure [7] a nested grid was developed in ECLIPSE, which allows a finer grid to be nested within a coarser grid. The size of the cells next to the wellbore was reduced from 50 m × 50 m to 5.5 m × 5.5 m after two levels of nested local grid refinement (LGR) in the area of 1000 m × 1000 m around the well, and then to 1.8 m × 1.8 m in the cells that the wells are located in, as shown in Figure 4. The maximum total number of active cells in the finest model after defining the LGR was about 4.5 million.

A grid sensitivity study was undertaken as a preliminary step to find the impact of the areal size of the grid on peak pressure within an affordable CPU time, as shown in Figure 5. It can be seen that the calculated injectivity converged when the grid size was reduced from 50 m to 2 m.

Simulations were performed using ECLIPSE E300 with the CO2STORE option, with three components (CO_2, H_2O and NaCl) to simulate CO_2 injection in the saline aquifer (salinity = 100,000 ppm) in the Forties Formation. The set of relative permeability curves, PVT data and fluid properties used in the ETI project were used in this project. The relative permeabilities were taken from Bennion and Bachu [8]– Calmar formation for the shale and Viking 2 for the sandstone. Note that because a constant injection rate is assumed, and post-injection long-term storage is not simulated in the study, hysteresis can be ignored because only the drainage cycle occurs within the simulation.

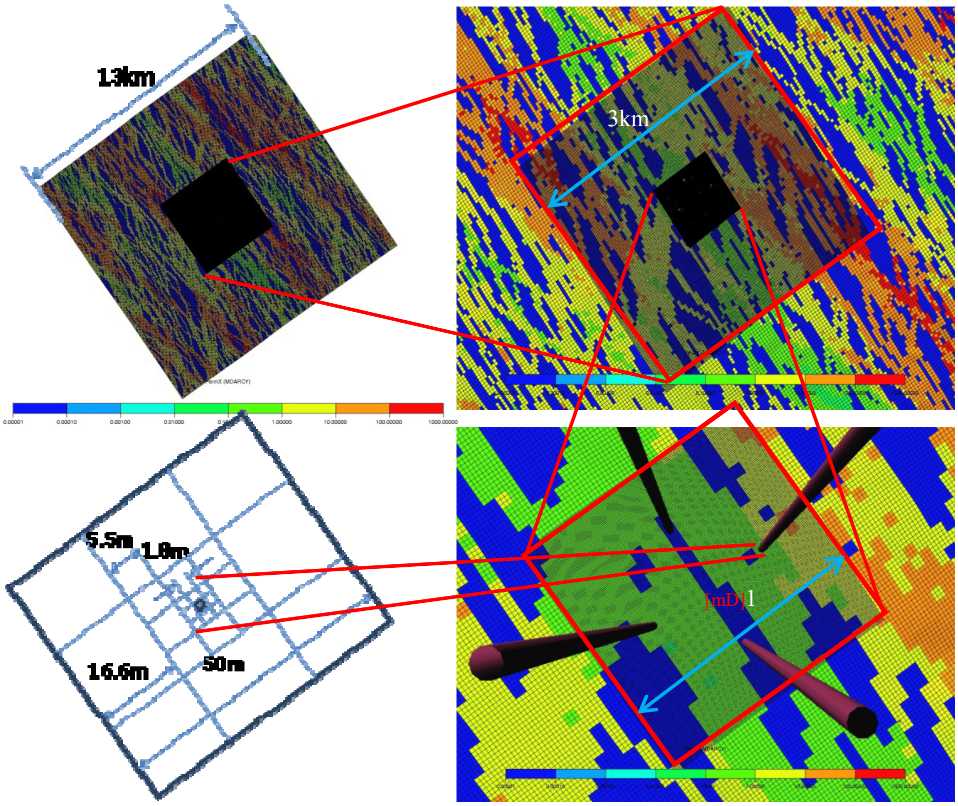


Figure 4 Model dimension, well location, and cell size in the four level nested local grid refinement shown on the permeability contour background from the F65-k10 model

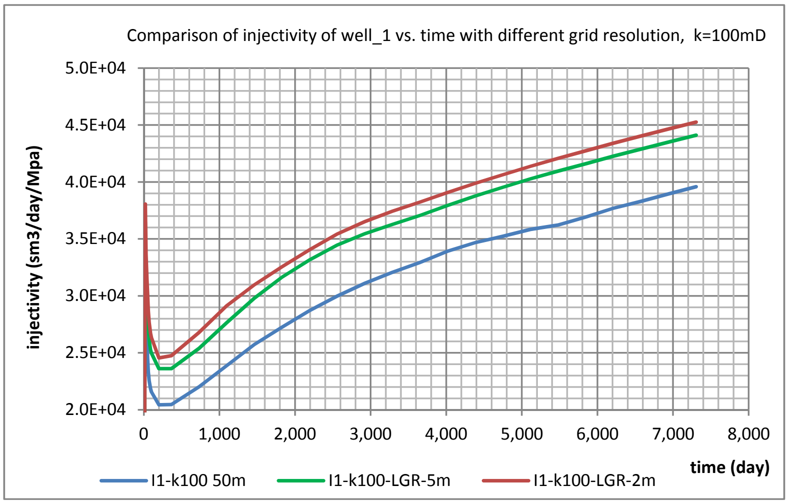


Figure 5 Injectivity calculated from three models with different grid resolutions: the blue line is from the 50 m x 50 m x 6 m model, the green line is from the 5.5 m x 5.5 m x 6 m model, and the red line from the 1.8 m x 1.8 m x 2 m model.

To aid our decision whether to use a radial or a Cartesian grid for the innermost local refinement, a sensitivity study was performed to compare the dry-out region (the region where the gas saturation Sg ~ 1) for the prediction of salt precipitation. It was found that there is no significant difference between the two kinds of gridding near the wellbore in this context. Therefore, it was decided to use a Cartesian LGR for the cell where the injector is located in order to reduce the CPU time.

In order to reduce the error caused by locating an injector on cells with extreme flow properties, and to represent a random output, four vertical injectors were used. They were perforated along the whole length, and were located on the four corners of a square with sides 350 m long, which is located in the center of the model as shown in Figure 4. These four wells, although each of the same length, will have different connectivity factors due to differences in the local permeability field around each well. The depositional system comprising sand-filled channels with interchannel mudstones and siltstones yields a heterogeneous system in which the finer grained intervals can act as barriers to fluid flow and so lead to compartmentalization of a reservoir. Thus the core data from certain sections may suggest much higher permeability than the effective permeability around the injector as a whole. The product of permeability and thickness along the well showed that about 80% of the injectivity could be attributed to only 20% of the completed interval, even though the entire well length from the top surface to the bottom surface was perforated.

The models were assumed to be bounded by numerical aquifers so as to account for the vast pore volume of the Forties Formation outside the model domain. CO_2 was injected into the model for 20 years at a rate of 0.5 Mt/year in each well. The injection rates were set to reduce once a maximum pressure of 39 MPa is reached. The parameters of the base case model are listed in Table 1. Results are compared in terms of peak well bottom hole pressure (WBHP), injectivity, CO_2 migration distance and dissolution. Twelve numerical models in total were constructed reflecting the different depositional systems, NTGs and mean permeabilities.

Table 1 Parameters for base case model of Forties Formation

parameters	unit	value
Model dimensions	m	13,050 x 12,600 x 170
Aquifer dip angle	°	0.77
Aquifer datum depth	m	2800
Pressure at datum	MPa	29
Temperature at datum	°C	105
Brine salinity	ppm	100,000
CO_2 density at datum	kg/m^3	760
CO_2 viscosity at datum	Ps-s	$6.344x10^{-5}$
Brine density at datum	kg/m^3	1150
Brine viscosity at datum	Ps-s	$6.06x10^{-4}$
Rock compressibility	MPa^{-1}	$5.567x10^{-5}$
Porosity (mean)		0.16
Permeability (mean)	mD	100
Permeability anisotropy (k_v/k_h)		1.0
Pore volume of storage site	m^3	$2x10^{10}$
Fracture pressure gradient	MPa/m	0.0181
CO_2 and water relative permeability functions		Viking 2 dataset [8]
Shale relative permeability function		Calmar dataset [8]
CO_2 injection rate		4 well x 0.5 Mt/year-well
CO_2 injection period	year	20
Grid horizontal resolution	m	50x50, 1.8x1.8 after LGR
Grid vertical resolution	m	4.6~7.0
Number of cells		1,973,160 (261 x 252 x 30)
		4,443,960 after LGR

4. Result and discussion

The results from the simulations are compared using the following parameters: WBHP (MPa) after one year of injection and at the end of injection (20 years), injectivity (sm3/day/MPa) which is calculated from the ratio of cumulative flow rate to pressure increase (Equation 1), and the distance of CO_2 migration from the injector (m).

The injectivity can be defined as the average flow rate divided by the pressure change since initialization; i.e.

$$J' = \frac{\int_0^T q(t)dt}{T \cdot \left(P_{wf} - P_0\right)} \quad (1)$$

where q(t) is the flow rate (m^3/day) at time t, P_{wf} is well bottom hole pressure (MPa) at time t, P_0 is the initial bottom hole pressure (MPa) at time t_0. T is the cumulated time (day).

The injectivity J' (m^3/day/MPa) was plotted against time, as shown in Figure 7, and was used to compare the response of each model to the variables.

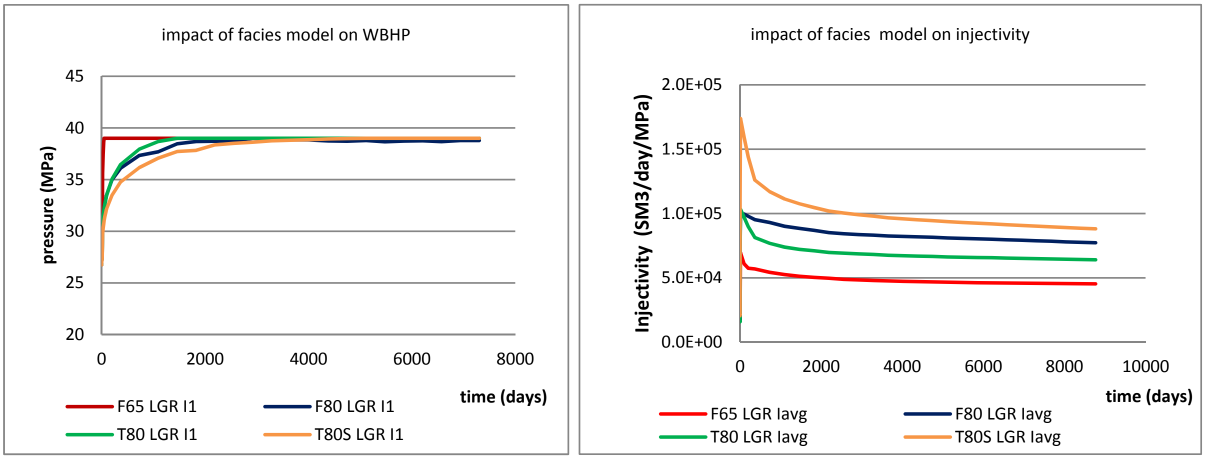
4.1. Sensitivity to facies types and NTG

As mentioned above, the four models represent two types of sedimentary system, Fluvial channel and Turbidite channels and two different NTG ratios, 65% sand and 80% sand. Two Fluvial models with different NTG ratio were used to study the impact of NTG on injectivity. Three models with the same NTG but different channel structures (F80, T80, and T80S) were used to study the sensitivity of facies to the injectivity. Two methods were used to generate the two Turbidite models with the same NTG ratio (80%); one was built using same method of object modelling as was also used for the fluvial model. The other was built by using a facies upscaling method to actually downscale the cell size from 200 m × 200 m in the ETI large scale model to 50 m × 50 m in the T80S model, but keep the realization properties the same as the ETI model in order to compare the result from the previous project with the results from these new facies models. The names of the models and their parameters are listed in Table 2.

Table 2 Models used in the sensitivity study of depositional system and NTG.

Model	Depositional System	Sand: Shale ratio (%)	Generated by
F65	Fluvial	63:35	keeping geophysical data from ETI model, but changing Facies type
F80	Fluvial	80:20	keeping geophysical data from ETI model, but changing Facies type
T80	Turbidite	80:20	inheriting geophysical data from ETI model with a new realization of facies, and fluid properties ϕ, and k
T80S	Turbidite	80:20	downscaling Facies from ETI model to current submodel, then generating ϕ, and k

Figure 6(a) shows a comparison of the WBHP of injector I1, which is in the same physical location (x,y) but the permeabilities are randomly distributed with the mean permeability equal to 10 mD, for the four models with different NTG and facies types. Figure 6(b) shows the injectivity change vs. time. The injectivities displayed in the figure are all for the mean value of four injectors. It can be seen from the figure that the F65-K10 model (where the mean permeability is 10 mD) has the sharpest increase in wellbore pressure at the beginning of the injection, and thus the lowest initial injectivity, compared with the other models. Another Fluvial model F80 has similar features. On the other hand, the T80S-k10 model, which has the widest sand-body channels of all the models, has the highest initial injectivity. The injectivities from all of the models with NTG=80 are much higher than the model with NTG=65. This is due to the high connectivity for all the models at the high NTG value. Over 90% of static connectivity (defined here as the connectivity between the opposite boundaries) was calculated for model F65, so that the static connectivity for the T80 models should be higher than the F65 model. Since the connectivity in a 3D model can be achieved at relatively low NTG values [9], similar injectivities calculated from all of the models with high NTG value is unsurprising. On the other hand, when the mean permeability of the channels is very low, the distribution of the channels may not help the pressure propagation. The results of the simulations in Figure 6 show that the impact of fine-scale stratigraphic heterogeneity on CO_2 injectivity is significant, although the importance was found to vary depending on NTG. The stratigraphic architecture does not affect the injectivity very much under condition of low mean permeability in the long term. The injectivity decreased quickly with the pressure build-up during the first 1000 days (3 years) as shown in Figure 6(a) and (b) for these models with low mean permeability.



(a) (b)

Figure 6 Bottom hole pressure vs. time (a) and injectivity reduction during CO_2 injection (b) for low permeability facies models (k = 10 mD).

4.2. Sensitivity to mean permeability

Permeability heterogeneity is also known as a parameter to affect connectivity and in return to affect the sweep efficiency and pressure propagation. In the second sensitivity study, the mean permeabilities of the three models are set to be 10 mD, 100 mD, and 1000 mD while the permeability of shale is kept unchanged to test the effect of the permeability contrast. In order to compare the injectivity the total pore volume is similar in these models by using the same mean porosity, and the same variation parameters and seed number for the distribution of the porosity. The model names are a combination of the facies type and the permeability. It can be seen from Figure 7 that the injectivity increases with the increase of mean permeability that is directly result in the increase of permeability thickness (kh) in the injection wells. The injectivity of the F65-k10 model is still the lowest, and the injectivity reduces with time quickly. The results for the other models were similar, so are not shown. With the increase of 10 times in mean permeability, the injectivity is doubled or tripled depending on which model is used. The reduction in injectivity becomes less significant in the k10 models. Pressure propagates more readily with an increase in the mean permeability, even though there is still a difference between the Turbidite model and the Fluvial model. The impact of NTG is lower in the high permeability model than it is in the low permeability model.

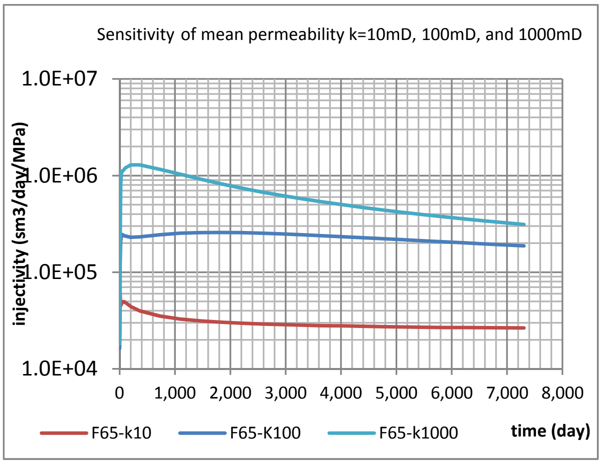


Figure 7 Injectivity reduction during CO_2 injection for models with the mean permeability from k = 10 mD, 100 mD, and 1000 mD.

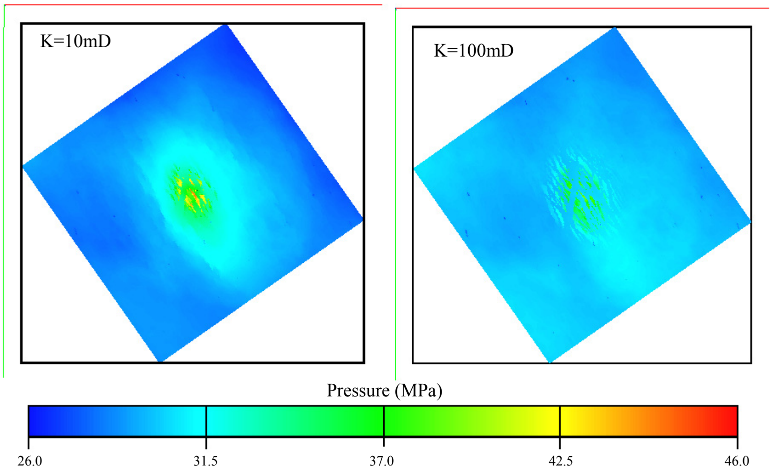


Figure 8 Comparison of pressure distribution from the top view of two Fluvial models, with the mean permeability k = 10 mD (left) and k = 100 mD (right). With high permeability channels, pressure propagation quick and injectivity is increased dramatically. Note that both models are connected with a huge aquifer at the boundary of the models. The pressure localization is due to the poor connectivity.

Figure 8 shows a comparison of pressure distribution from a top view of the two F65 models with k = 10 mD and k = 100 mD, after 20 years of injection. The total pore volume in the two models is the same, but because of the limitation of maximum injection pressure, the volume of CO_2 (in surface units) injected into the aquifer is doubled in the high perm model. CO_2 moves faster in the high-perm, channelled system. The distance between the plume boundary and the injectors is also doubled in the high permeability case. As concluded in the ETI UKSAP project, the low permeability system has poor injectivity, but good storage security. The high permeability channel system has good injectivity, but the migration velocity is much higher. The storage capacity depends on the trapping mechanisms. However, from the point of view of the CO_2 storage once it has been successfully injected, the permeability, the dip angle and geological heterogeneities may have a positive or a negative impact, depending on the volumes injected, migration pathways and potential leak points [3].

The velocity of migration 1000 years after injection can be calculated analytically based on the study in the ETI UKSAP project [3, 10] , in which the parameter sensitivity was investigated under the combination effects of plume migration over longer time scales (1000 years). Due to the length of run times and the fact that this project is aimed at studying injectivity, a long term simulation was not performed to compare the numerical simulation with the analytical calculations for equivalent time periods.

Since the distribution of permeability is generated randomly, the impact of the locations of the four wells on their injectivity represents an additional source of relevant uncertainty. The calculated injectivities for the four wells in each model show a range of variation. However, as all of the injectors are vertical wells and are completed from the top layer to the bottom layer, it is found that the effect of connectivity between the well and the formation does not strongly affect injectivity. In this example the largest difference is about 7% in one model. However, it is difficult to compare the results which are induced by high permeable channels between the models without taking out the change due to the well connectivity (i.e. kh value) even though the four wells are located randomly, and the distribution of permeability and porosity are kept unchanged.

4.3. Sensitivity to grid resolution

The results from F65-k10 with four different grid resolutions were compared during the project. The four degrees of grid resolution are:

- Upscaled using Root Mean Squared (RMS) method [11] from 50 m × 50 m × 6 m to 400 m × 400 m × 6 m;
- ETI model, 200 m × 200 m × 3 m;
- Base case model without LGR, 50 m × 50 m × 6 m;
- Base case with nested LGR, 1.8 m × 1.8 m × 2 m.

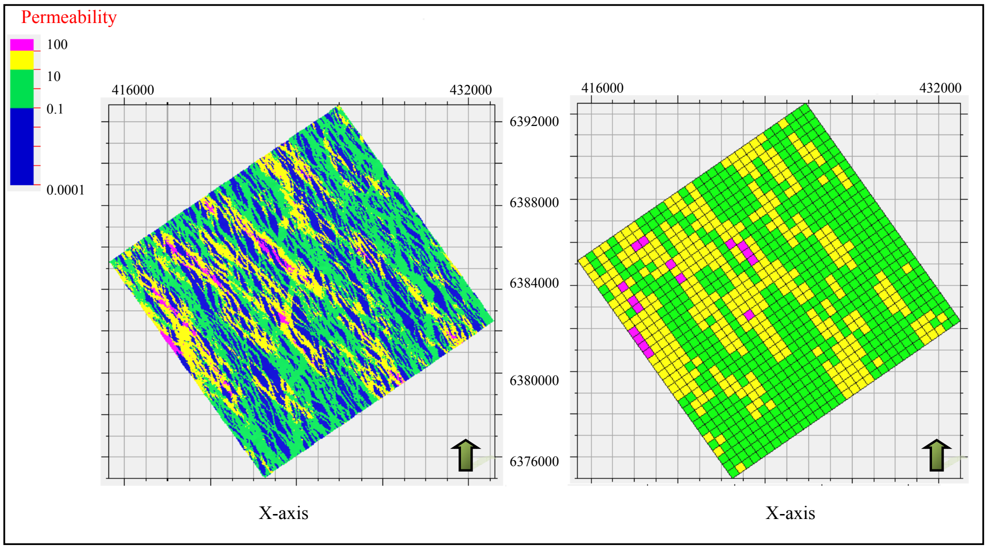


Figure 9 Permeability distribution before (left) and after (after) upscaling. The cells are increased in size from 50 m × 50 m to 400 m × 400 m after upscaling.

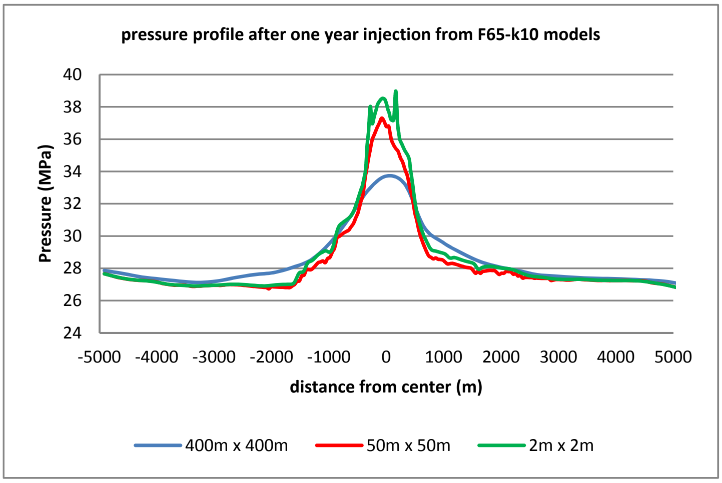


Figure 10 Cell pressure along a cross-section through injector I1and I2 in three models with different grid resolutions; the red line is from the 50 m x 50 m model, the green line from the 2 m × 2 m model, and the blue line from the 400 m × 400 m model.

Figure 10 shows cell pressures along the same cross section that goes through injector I1 and I2, and along the x direction, in three models with different grid resolutions, as stated above. The x axis shows the distance from one side of the model and the y axis shows the pressure in MPa. The results show that the peak pressure near the wellbore was not caught in the coarse model. There is a 4 MPa difference between the peak value in the fine model and in the coarse model. In other words, if the injector is controlled by WBHP, the injectivity is overestimated by the coarse model. At the same time, the pressure propagation is faster in the coarse model than in the fine models. This is caused by the upscaling method, which increased the permeability in the low permeability cells, for example the shale cells. Because the LGR model does not give higher resolution in the distribution of properties, and it is only refined in the area near the wellbore in the vertical direction (from 30 layers into 90 layers), it does not affect the prediction very much compared with the 50 m x 50 m model in terms of both the peak pressure and the distribution of the pressure along the cross-section.

5. Conclusions

Incorporating the fine-scale heterogeneity associated with channel structures led to a basin-scale reservoir model containing 4,443,960 cells. For the finest scale models studied, 20 years of injection time took 20 days to run despite using a parallel version of ECLIPSE on a 12 processor cluster. The results from basecase and sensitivity study cases provides engineers with information on the balance between building a large-scale CCS model with detailed geological stratigraphy and efficiently use of stochastic generated distribution to represent the heterogeneity of fluid properties.

The results of the simulations show that the impact of fine-scale stratigraphic heterogeneity on CO_2 injectivity is significant, although the importance was found to vary depending on

- the contrast of permeability between shale and sand, and
- under some circumstances, the NTG

When the mean permeability is low (say less than 10mD), NTG has a big impact on injectivity. Facies type does not show a big influence on the change of injectivity. Even though a good static connectivity can be calculated for a model, the result from dynamic simulation shows a high-pressure localization. When the mean permeability is greater than 10 mD, the injectivity depends on both NTG and the facies type, i.e. the spatial connectivity to the CO_2 injection well. The peak value of injectivity appears much earlier in the turbidite models (ca. 400 days) than in the fluvial models (more than 1000 days). The sensitivity study shows that the grid resolution affects the peak value of wellbore pressure. Thus, in a coarse model the well bottom hole pressure required to achieve a given injection rate will be underestimated, and as such the injectivity may be overestimated.

Overall, it is concluded that the incorporation of fine scale heterogeneity (<10s m) is necessary in the near wellbore zone for CO_2 storage simulation, even though basin scale modelling is required to capture pressure response and impact of interference with other activity in the connected pore volume. This work highlights the importance of developing reliable upscaling methodologies so as to reduce computational time of simulations and better allow for the practical possibility of probabilistic assessments, using multi-realisation methods such as Monte Carlo simulation.

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