Programme Area: Carbon Capture and Storage

Project: Aquifer Brine

Title: Initial Technical Analysis of Exemplar CCS Stores

Abstract:

This project aims to address whether or not there is potential to significantly increase CO2 storage capacity, and thereby reduce overall cost of storage, by producing brine through dedicated production wells from target storage formations. Brine production is proposed as a method to manage pressure in storage sites, as a corollary to water injection during hydrocarbon extraction. In the case of CO2 storage, the production of water creates voidage to increase storage capacity and reduce the extent of pressure increase due to CO2 injection, and hence reduce the risk of caprock failure, fault reactivation and induced seismicity; additionally, it reduces the energy available to drive fluids through legacy well paths and other potential seep features. Spatially the reduction in the extent of the pressure plume reduces the affected area which can reduce the area of potential drilling interference, the number of impacted legacy wells, and the area of investigation for monitoring where brine movement is a concern. In this report five systems are considered: the Forties Aquifer, the Bunter Aquifer, the depleted Hamilton gas field, a producing North Sea oil field, and a synthetic tilted aquifer. The well counts, the period and the rate of brine production are data that are supplied for economic analysis to determine whether or not the process is a viable means of increasing storage capacity and reducing overall costs.

Context:

This £200,000 nine-month long project, studied the impact of removing brine from undersea stores that could, in future, be used to store captured carbon dioxide. It was carried out by Heriot-Watt University, a founder member of the Scottish Carbon Capture & Storage (SCCS) research partnership, and Element Energy. T2 Petroleum Technology and Durham University also participated in the project. It built on earlier CCS research work and helped develop understanding of potential CO2 stores, such as depleted oil and gas reservoirs or saline aquifers, located beneath UK waters. It also helped to build confidence among future operators and investors for their operation. Reducing costs and minimising risks is crucial if CCS is to play a long-term role in decarbonising the UK's future energy system.

Initial Technical Analysis of Exemplar Stores

Min Jin, Peter Olden, Gillian Pickup and Eric Mackay

Heriot-Watt University

Reviewed by Davey Fitch

Scottish Carbon Capture and Storage

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Executive Summary

This project aims to address whether or not there is potential to significantly increase CO_2 storage capacity, and thereby reduce overall cost of storage, by producing brine through dedicated production wells from target storage formations. Brine production is proposed as a method to manage pressure in storage sites, as a corollary to water injection during hydrocarbon extraction. In the case of CO_2 storage, the production of water creates voidage to increase storage capacity and reduce the extent of pressure increase due to CO_2 injection, and hence reduce the risk of caprock failure, fault reactivation and induced seismicity; additionally, it reduces the energy available to drive fluids through legacy well paths and other potential seep features. Spatially the reduction in the extent of the pressure plume reduces the affected area which can reduce the area of potential drilling interference, the number of impacted legacy wells, and the area of investigation for monitoring where brine movement is a concern.

In this report five systems are considered: the Forties Aquifer, the Bunter Aquifer, the depleted Hamilton gas field, a producing North Sea oil field, and a synthetic tilted aquifer. The well counts, the period and the rate of brine production are data that are supplied for economic analysis to determine whether or not the process is a viable means of increasing storage capacity and reducing overall costs.

The Forties system is sufficiently large that for lower CO_2 injection rates (order 2-5 Mt/y), brine production does not yield any increase in storage capacity, and therefore should not be considered. For an intermediate injection rate (10 Mt/y) the capacity of the system is such that initially there is no benefit from brine production. However, as pressure builds up over time, brine production becomes an increasingly useful method of increasing storage capacity. Above 15 Mt/y CO_2 injection rates, brine production should be considered from the outset. At very high injection rates, say 40 Mt/y, breakthrough of CO_2 at the production wells is so quick that the benefit of brine production is short lived.

In the **Bunter system** studied, as with the Forties system, at lower CO_2 injection rates brine production yields no benefit. The nature of the Bunter aquifer, with higher permeabilities and dome structures results in higher injection rates being possible with no benefit from brine production – up to 15 Mt/y. Also, the higher permeabilities mean that even at these higher injection rates, fewer brine production wells are required to provide the required pressure management.

The CO_2 storage capacity of the depleted **Hamilton gas field** can be enhanced by brine production and further enhanced by low injection rates, consistent with maintaining the store pressure above that required for super-criticality of the injected CO_2. The predicted capacity is constrained by the permitted CO_2 flow rates, either in the brine production wells or migration to parts of the formations outwith the original area of the hydrocarbon trap. Given this constraint, the potential for extension of life as a store is significant.

In the case of the **North Sea oil field** studied, water injection can be partially replaced by CO_2 injection deep into the aquifer, and despite CO_2 breakthrough at the producers (and hence a need to recycle CO_2) a net amount of 54 Mt of CO_2 can be stored over a 20 year period, whilst increasing the oil recovery factor from 54% under pure water flooding in that same time period to over 59%, and reducing the requirement for water injection (with a modest reduction in water production also). The improvement in oil recovery may be attributed to microscopic (reduction in residual oil saturation in contacted zones) and macroscopic (better sweep efficiency) mechanisms. The prime interest in this study is, however, the potential to use CO_2 injection deep into the aquifer to at least partially replace water injection, here *reduced* water injection having a similar impact on storage potential to water production considered in the other cases studied.

Calculations of number of CO_2 injection and brine production wells, along with periods of production, flow rates and maximum pressures are then provided as input for economic analysis, comparing cost of CO_2 injection alone to cost of CO_2 injection supported by brine production – this work is being carried out by Element Energy in another work package. A fifth synthetic case demonstrates that very significant increases in capacity can be achieved in gravity stable scenarios.

During the next phase of this project, there will be a closer examination of the stores which show that there is potential benefit due to brine production, and the work will provide further information on (a) how to optimise the input parameters, as well as (b) drawing conclusions for which type of stores should (or should not) be considered for brine production from the large number of stores in the CO_2Stored database. The synthetic tilted aquifer model and a generic box model will also be used to test the impact of various scenarios, including due to uncertainty in the underlying geological models, and the impact of inter well distances.

Contents

Nomenclature

BHP	Bottom hole pressure in wellbore
BGS	British Geological Survey
CCS	Carbon Capture and Storage
ESP	Electrical Submersible Pumps
E100	Eclipse 100 – Black oil simulator from Schlumberger
E300	Eclipse 300 – Compostional simulator from Schlumberger
FFM	Full Field Model
FGIR	Field CO_2 injection rate
FPR	Field average pressure
ft	foot (= 0.3048m)
GIIP	Gas initially in Place
GWC	Gas Water Contact
HWU	Heriot-Watt University
Kh	Horizontal permeability
Kv	Vertical permeability
MMP	Minimum miscibility pressure
MMscf	million standard cubic feet (= 28316.8 m^3)
PBD	PaleBlueDot
psi	pound per square inch (= 6894.757 Pa)
PVT	Pressure Volume and Temperature
SCCS	Scottish Carbon Capture and storage
stb	stock tank barrel (= 0.15898284 m^3)
TVDSS	True Vertical Depth Sub Sea
UKCS	United Kingdom Continental Shelf
UKSAP	United Kingdom Storage Appraisal Project
WBHP	Well Bottom Hole Pressure
WGPR	Well gas production rate
WXMF_1	produced CO_2 mole fraction from a water producer
ΔP	differential pressure (current BHP – initial BHP)

1. Introduction

The Energy Technologies Institute (ETI) *United Kingdom Storage Appraisal Project* (UKSAP) was undertaken to assess the CO_2 storage potential in the rock formations underlying the offshore UK Continental Shelf (UKCS), and led to the initial development of the CO2Stored database and website. UKSAP, completed in 2011, was delivered by a consortium of project partners, including Senergy Alternative Energy Ltd, BGS, the Scottish Centre for Carbon Storage (University of Edinburgh, Heriot-Watt University), Durham University, GeoPressure Technology Ltd, Geospatial Research Ltd, Imperial College London, RPS Energy and Element Energy Ltd., (Gammer et al., 2011). Data were gathered about formations which met certain criteria (such as porosity and permeability constraints, the presence of impermeable caprocks, etc) that meant they could potentially act as storage sites. Aquifers and producing hydrocarbon fields were considered. The limiting factor for storage capacity was generally pressure increase and the risk of fracturing the caprock, although migration of CO_2 beyond a predetermined spill point was also considered. However, the impact of deliberate pressure relief to increase CO_2 storage capacity was outside the scope of UKSAP.

The current ETI funded project, *Impact of Brine Production on Aquifer Storage*, aims to address whether or not there is potential to significantly increase storage capacity, and thereby reduce overall cost of storage, by producing brine through dedicated production wells, as demonstrated in the final report of the Scottish Carbon Capture, Transport and Storage Development Study (Akhurst et al., 2011). This is proposed as a method to manage pressure in storage sites, as a corollary to water injection during hydrocarbon extraction. In the case of CO_2 storage, the production of water creates voidage to increase storage capacity and reduce the extent of pressure increase due to CO_2 injection, and hence reduce the risk of caprock failure. Thus it would be possible to inject CO_2 at a higher rate into a given store, or inject for longer, rather than developing another storage site to meet the required storage volume. In addition to the potential increase in CO_2 storage capacity, the production of water reduces the areal extent of pressure increase due to CO_2 injection, and hence, as well as reducing the risk of caprock failure, fault reactivation and induced seismicity, it reduces the energy available to drive fluids through legacy well paths and other potential seep features. Spatially the reduction in the extent of the pressure plume reduces the affected area which can reduce the area of potential drilling interference, the number of impacted legacy wells, and the area of investigation for monitoring where brine movement is a concern.

In the published development plan for the Chevron operated Gorgon project at Barrow Island, Western Australia (Chevron Australia, 2016), 220 MMscf/d of CO_2 injection into the Dupuy Formation through nine injectors is “supported” by some 60,000-80,000 stb/d brine production through four producers located approximately 4-6 kms distant (Chevron Australia, 2016). The brine production is facilitated by Electrical Submersible Pumps (ESPs), with the brine being displaced into the overlying Barrow Group by means of pressure management wells.

This report, which aims to detail an initial technical analysis of exemplar stores in the UKCS, shows that increased CO_2 storage capacity can be achieved, and provides data that can be used for an economic evaluation of the impact of brine production on the overall cost of CO_2 storage projects. The exemplar sites are chosen from both aquifers and hydrocarbon producing fields. In the case of the aquifers, the UKSAP methodology of calculating number of CO_2 injection wells as a function of required injection rate and of injection duration is followed. In the case of the hydrocarbon fields, the impact of historical hydrocarbon production is taken into account – something not done in UKSAP.

In both the aquifer and the hydrocarbon field scenarios, the objective of this work is to evaluate the number and timing of brine production wells that are additionally considered, and the impact this has on CO_2 injection capacity and formation pressure. These data are then supplied to project partners (Element Energy) to evaluate whether or not any additional injection capacity (within the pressure constraints) warrants the cost of incremental infrastructure required for the brine production. The evaluation of the facilities required to process and displace produced brine is considered in this project by project partners Element Energy and T2 Production Technology, but is not described in this report.

This report details calculations that are used to demonstrate the methodology and considers scenarios that may yield benefit, but does not provide an optimised solution for each case. Indeed, it is to be expected that some scenarios will not prove cost effective. However, it is important that a robust methodology is developed.

In addition to providing data similar, or in extension to, the type of data generated during UKSAP, this project also considers possible innovations, such as:

- altering the timing of brine production to best suit the need to manage pressure;
- the opportunity to use brine production to increase the injection capacity in depleted gas reservoirs; and
- the opportunity not to produce brine, but to decrease brine injection in waterflooded oil reservoirs to achieve the same net effect of increased voidage to maximise CO_2 storage.

The difference with the latter scenario is that the voidage is achieved by oilfield production, with the injected CO_2 replacing (or partially replacing) seawater injection wells as the pressure support mechanism, albeit the CO_2 injection wells are set deep within the adjoining aquifer.

In each exemplar store case considered, calculations are performed using a reservoir simulation model - a single geological realisation of the system - since the purpose of the study is to identify the potential for improvement in storage capacity, not the impact of geological uncertainty. Geological uncertainty is an important issue, and would need to be considered in any detailed assessment of a potential store. In particular, as with waterflooding of oilfields, breakthrough of the injectant at production wells can detrimentally affect the efficiency of the process, and this in turn can be strongly affected by heterogeneity in the system geology, and the balance between viscous, gravitational and capillary forces. This means that optimisation of a specific storage site would have to take account of the uncertainty in the geological description, and would have to consider the ideal inter-well distances that would maximise pressure relief whilst minimising CO_2 breakthrough, which would be dependent on the geological description. While this optimisation is beyond the scope of this current study, analysis of synthetic systems currently under way (but not reported here) will consider the impact of geological heterogeneity on the process. This activity will identify what are the key geological uncertainties that need to be taken into consideration.

Following a site screening process, the Forties and Bunter aquifers, the Hamilton Gas Field and a North Sea oil field were chosen as initial study cases in this project. The process involved Heriot-Watt University and ETI assessing the different types of structure identified during UKSAP (Gammer, 2011), and ensuring that these structures were represented in the selected list of sites. Availability of datasets that were already developed to perform CO_2 injection calculations was another factor, since the setup and verification of such models can be time consuming. The two aquifers were chosen as two exemplars from ETI UKSAP because of their generic storage unit types, i.e. open with structural/stratigraphic confinement (Forties) and Structural/stratigraphic trap (Bunter). There are two models, a PaleBlueDot (PBD) model and a Heriot-Watt University (HWU) model, available for each aquifer, although the location of the two Forties models are not exactly in the same area. The Hamilton Gas Field model was supplied by PBD, and the North Sea Oil Field model has been supplied by an operating company on the condition of anonymity.

Both of the aquifers are large in terms of potential storage capacity (100s Mt), but with different geological features and properties which may cause different CO_2 migration and pressure propagation effects. The Hamilton Gas Field is relatively much smaller, and the North Sea Oil Field, while larger than the Hamilton Gas Field, is small relative to the aquifers.

Additionally, a case study of a synthetic, steeply dipping system uses the geological description of an existing subsurface formation and considers CO_2 injection near the top of the structure with brine production at various distances downdip.

Several pre-simulation studies were carried out before running the reported simulations. One of the activities was a study on well spacing. A 5-spot model was used with the properties of Forties and Bunter formations. By fixing the size of a cell (400m x 400m areally) and changing the distance between one injector and one producer, it was possible to identify the relation between injection rate and the CO_2 breakthrough time. Another sensitivity study was performed to compare vertical injectors/producers and horizontal injectors/producers under the conditions of offshore CCS in order to reduce the total number of platforms. In order to assess the differences that may arise due to the use of different types of simulator, i.e. black oil E100 simulator or compositional E300 simulator, the E100 Forties model from PBD was converted into an E300 model. The results from the two simulations were compared, particularly the properties of CO_2 and the amount of brine containing dissolved CO_2. The major differences arose not from differences in fluid property input parameters or calculations, but from the fact that the PBD model included hydrocarbon extraction prior to CO2 injection, whereas the HWU scenario did not include this.

In the main simulation stage, two groups of calculations were performed. One group provides the base reference case in which no water production was used. The field injection rates were set to 2, 5, 10, 15, 20, and 40 Mt/year. The injection periods were 10, 20, 30, and 40 years. The minimum number of wells required for each case was entered into a table, using the same format as those in the CO2Stored website. The second group of simulations is a comparison group including water production. Three different injector-producer patterns were used for each case, and then the minimum numbers of injectors and producers were entered into a second table. At the same time, other data such as the maximum water production rate, the water injection period and starting time were also calculated and entered into the corresponding tables. In order to keep the study generic the well locations were chosen without detailed optimisation, even though the injection capacity of some layers would be low.

2. Forties Model

The Forties geological model is a section of the Forties sandstone member originally selected in the UKSAP, as shown by the red rectangle in Figure 2-1. Unlike the PBD model, which considers a different section of the Forties Sandstone member, there are no hydrocarbon fields and no significant structural closures within the area. The area of interest was 21.4 km x 36 km (Goater et al., 2013). The grid dimensions of the model were 52 x 89 x 18 cells, giving a total of 83,304 active cells. This was reduced from an original 1,733,400 (107 x 180 x 90) cell model.

The data for the HWU model are listed in Table 2-1, with comparison to the PBD model and data from the CO2Stored database.

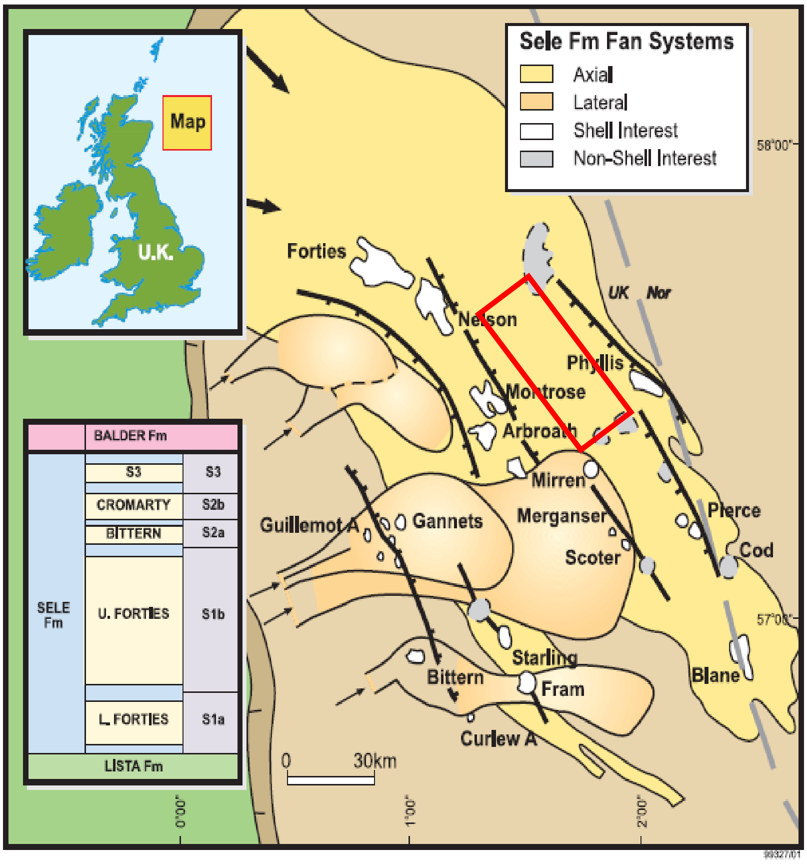


Figure 2-1 Location of the Forties Sandstone member and the Forties geological model (red rectangle). After Senergy (2011).

Table 2-1 Parameters from CO2Stored website and used for Forties models.

Parameter	Units	PBD E100 MODEL	HWU E300 MODEL	Forties 5 (372.000)
area	km^2			13803
average thickness	m	275	171	98
average porosity	fraction	0.1738	0.155	0.24
average permeability, kx	mD	36	9.93	194
average permeability, kz	mD	28	9.93	
average vertical N/G				0.64
total Pore Volume, PV	m^3	4.0×10^{11} (at Pref=281 bar)	2.06×10^{11} (at Pref=274.8 bar)	2.057×10^{11}
rock compressibility	1/bar	4.89×10^{-06}	5.57×10^{-05}	4.89×10^{-05}
water compressibility	1/bar			3.38×10^{-05}
initial pressure	bar		290	288
datum depth	m		2840	2336
fracture pressure	bar	405	390	425.2
water density	kg/m^3	1065.0		
CO_2 density	kg/m^3	1.87		630
brine viscosity	cP			0.36
CO_2 viscosity	cP			0.0554
salinity	ppm	94000	250000	89000
temperature	deg C	100	115	104
PV utilisation	frac			0.54
theoretical capacity	Mt			1859
dynamic utilisation	Mt			1600
model dimension	km x km	42x48	20.8x35.6	
No. cells in each direction		105x120x61	52x89x18	
total No. cells		768,600	83,304	
total No. of active cells		331,180	83,304	
cell dimensions in X & Y	m	400x400	400x400	
cell dimensions in Z	m	4.5	9.5	
injection rate	Mt/y	7	40	
injection period	y	40	40	
monitoring period	y	3500	1000	

2.1. Comparison of PBD model with HWU model

The input parameters are compared and listed in Table 2-1. The HWU model was taken from a different location of the Forties sandstone member, and since the PBD model included an oil production history match, in the PBD model the formation was depleted before CO_2 injection in 2027. The fact that the HWU model was not depleted by the regional production from the Forties does not mean that this model overestimates the benefit of brine production, since the majority of oil fields in the UKCS, including those in the Forties, are or have been waterflooded to, *inter alia*, replace voidage and hence maintain pressure at or near original pressure. The pressure gradient in the HWU model was set to 0.545 psi/ft based on CO2Stored.

The rock compressibility in the PBD model is 3.37×10^{-7} 1/psi at 4641 ft (equivalent to 4.89×10^{-6} 1/bar at 1414 m), which is lower than the compressibility of water (4.0×10^{-5} 1/bar). The average permeability in the HWU model (obtained from UKSAP) is lower than in the PBD model.

3. Bunter Model

Figure 3-1 shows the Bunter formation with structural closures, the orange rectangle shows the section modelled and the black boundary outside the section was identified as Zone 4 (unit 139.000) in the CO2Stored database. Closure 36 (coloured green) in the orange rectangle is the closure on which the PBD model is based. The HWU model is based on the entirety of the orange rectangle.

3.1. Comparison of PBD model with HWU model

The main difference between the PBD and HWU models is the area encompassed by the models. The dimension of the PBD model is nearly one quarter that of the HWU model. Only one closure was included in the PBD model. If injected CO_2 passes the spill point of this model, it is considered to be moving out of the monitoring area. In the HWU model, injected CO_2 may move from one dome to another, but it would still be within the storage complex boundary. From Table 3-1 it can be seen that both the PBD and the HWU models used Zone 4 as the outer boundary of their model, since each model has a pore volume of approximately 300 km^3. In other words, the two models have a similar static storage capacity, where this is the capacity calculated based on the total pore volume, system compressibility and maximum allowable pressure, and does not consider CO_2 migration. (In the PBD model supplied, an injection rate of 7 Mt/year can be sustained for almost 55 years, giving a capacity of 384 Mt, which is close to the capacity of Zone 4 listed in Table 3-2, even though the PBD model only includes Closure 36.)

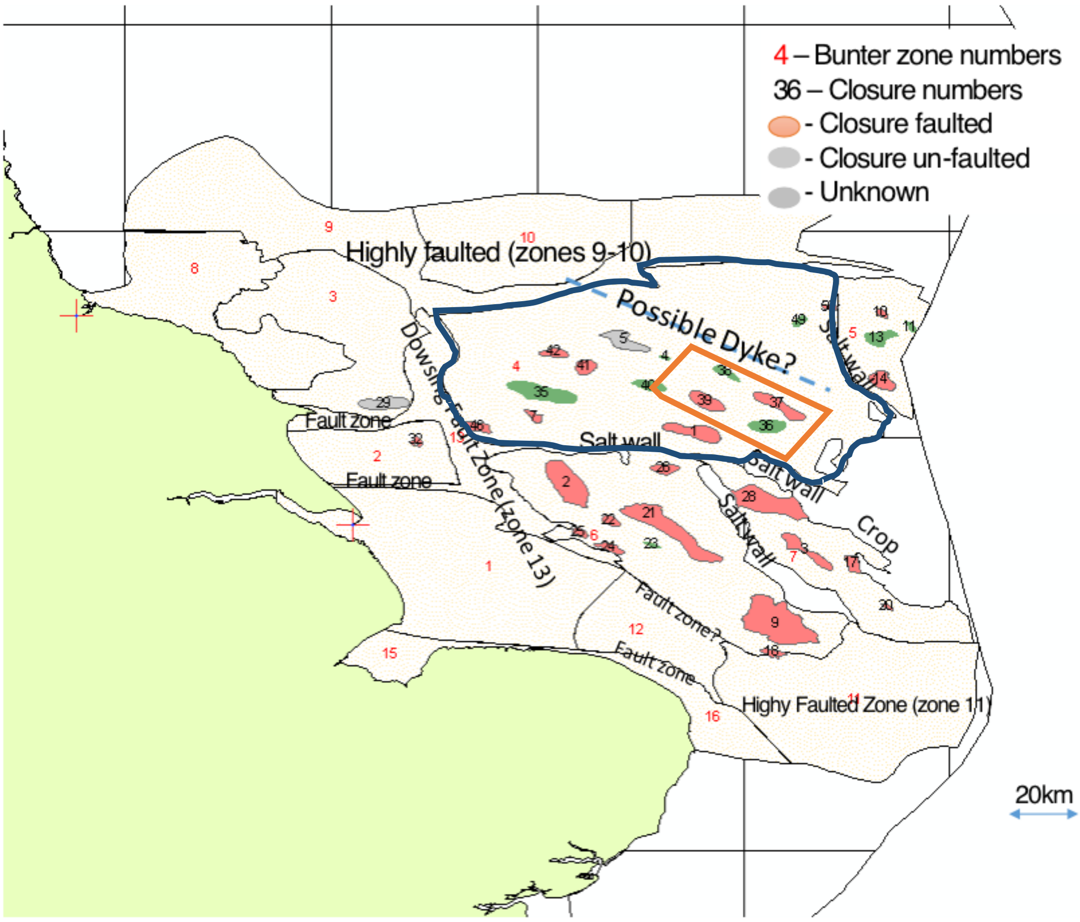


Figure 3-1 Bunter formation with structural closures, in which the orange rectangle shows the section in the HWU model and the blue boundary outside the section was named Zone 4 (unit 139.000) in the CO2Stored database (which includes 50 closures). Closure 36 coloured green in the orange rectangle is the closure the PBD model is based on.

Another significant difference between the two models is due to the vertical zonation or layering. As shown in Figure 3-2, in the HWU model several low permeability layers, such as layer 53 and layer 64, divide the whole formation into different zones. CO_2 can be injected into the layers above or below layer 53, but the pressures in each region will not be affected by each other.

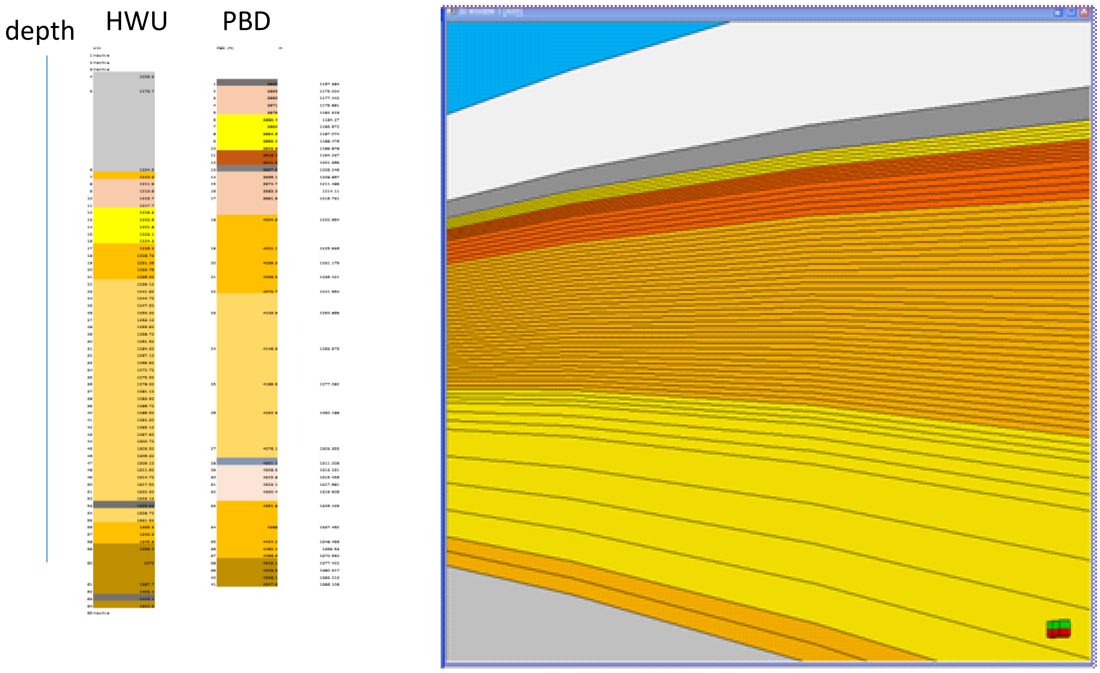


Figure 3-2 Geological zones in Bunter HWU model, showing several low permeability layers to separate the whole formation into different zones.

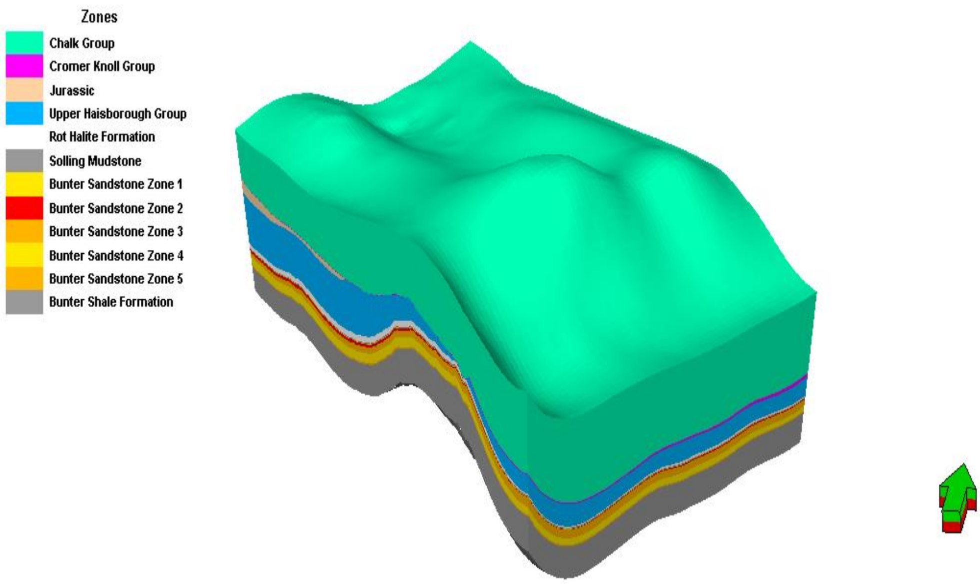


Figure 3-3 HWU Bunter model with zones.

Table 3-1 Comparison of parameters in Bunter Models and CO2Stored database.

Parameter	Units	PBD E100 MODEL	Bunter Closure 36 (139.016)*	HWU E300 MODEL	Bunter zone 4 (139.000)
area	km^2	664	71.1	1108	11640
average thickness	m	235	221	260	198
average porosity	fraction	0.175	0.17	0.144	0.14
average horizontal perm	mD	152	50	188	100
average vertical perm	mD	35	50	188	100
average vertical N/G			0.91		0.91
total PV	m^3	$2.68x10^{11}$ (2)	$2.40x10^{09}$	$3.07x10^{11}$	$2.798x10^{11}$ ($2.987x10^{11}$)**
rock compressibility	1/bar	$5.57x10^{-05}$	$5.69x10^{-05}$	$5.57x10^{-05}$	$6.20x10^{-05}$
water compressibility	1/bar			$4.0x10^{-05}$	$3.54x10^{-05}$
initial pressure	bar	121	158	155	160
datum depth**	m	1211	1569	1450	1591
fracture pressure	bar	183.4	277	210	171
CO_2 density	kg/m^3		847.5		325
brine viscosity	cP				0.39
CO_2 viscosity	cP				0.0296
salinity	ppm	200,000 (3)	180,000	213,500	180,000
temperature	deg C	40 (3)	43.3***	62	62 (1) (112.6***)
PV utilisation	frac		0.118		0.59
theoretical capacity	Mt		248		436
dynamic utilisation	Mt		200		400
model dimensions	km x km	24.8 x 26.8		44 x 25.2	
No. cells in each direction		124x134x41		110x63x65	
total No. cells		681,256		450,450	
total No. of active cells		603,364		429,660	
cell dimensions in X & Y	m	200x200		400x400	
injection rate	Mt/y	7		40	
injection period	y	56		40	
monitoring period	y	0		1000	

* Data from www.co2stored.co.uk, P50 value used ** values are different in different forms on the website
*** if data for centroid depth is given, then datum uses this depth, otherwise, shallowest depth is used
[1] from children unit data (oil or gas field data) [2] from Eclipse model statistics result or PRT output
[3] estimated from ETI-UKSAP RPS PVT tables

The situation is similar in the PBD model, but here the top zone was isolated from the bottom zone by layer 13. If the pressure monitoring well was set on the top part of the crest in the PBD model, it would not be sensitive to the pressure change due to injection in the middle or bottom zones. As a result, in the PBD model the top of layer 13 was taken as the primary seal, and the top layer of the overall model was the secondary seal.

The pressure was monitored along the whole well path by taking all the block pressures and comparing with allowed maximum pressure to decide whether injection can be continued. This choice was made because the highest pressures were to be found in the cells around the injector. In the HWU model the pressure monitoring point is at the top of the formation (layer 8). Fracturing in layer 53 might help to release pressure in the bottom zone, and also to slow down the migration speed as the bottom zone is a high permeability zone. Figure 3-3 shows the sandstone layers in relation to the other overlying formations, and Table 3-1 provides a comparison of the model parameters between the PBD and HWU models and CO2Stored.

3.2. Comparison of three injector-producer pattern

3.2.1. Criteria that control the injection process

There are three criteria used in this study to control the CO_2 injection and water production.

1. When the grid block pressure, BPR, in a block that is along an injector or at the crest of the structure exceeds the maximum allowed pressure, which is 0.9 times rock fracturing pressure, then injection in the well stops;
2. When the gas production rate from a water producer, WGPR, is over 1 Mscf/d (28 sm^3/d), or
3. When the produced CO_2 mole fraction from a water producer, WXMF_1, is over $1x10^{-4}$, then the producer is shut down.

Because the CO_2 dissolves in brine once it is injected and then flows with the brine towards the water producer, it can move faster than CO_2 in the gas phase. Criterion 3 is calculated based on Criterion 2 at a production rate of 2000 sm^3/d. However, Criterion 2 is an absolute limit, i.e. no matter how large the water production rate is, the gas production rate cannot exceed 1 Mscf/d. Criterion 3 is a relative value, as it is a ratio relative to the rate of water production, WWPR. When WWPR increases from 2000 sm^3/d to 20000 sm^3/d, CO_2 produced with water also increases 10 times, but the mole fraction may not necessarily be changed.

In this study, most of the cases where a producer is shut down were caused by breaking the WXMF criterion, rather than the WGPR criterion. The CO_2 migration path was diverted by the fact of water production. Figure 3-4 shows an example, where relocation of a production well resulted in a near doubling of the injection period before CO_2 breakthrough took place, and a tendency for CO_2 to migrate towards the production well delaying the migration towards a spill point. Therefore, it was found from the study that the location and spacing of the water producers are key in the use of this technique. They control the timing of CO_2 breakthrough and the efficiency of water production in terms of the amount of CO_2 that may be injected before it reaches a producer or a spill point.

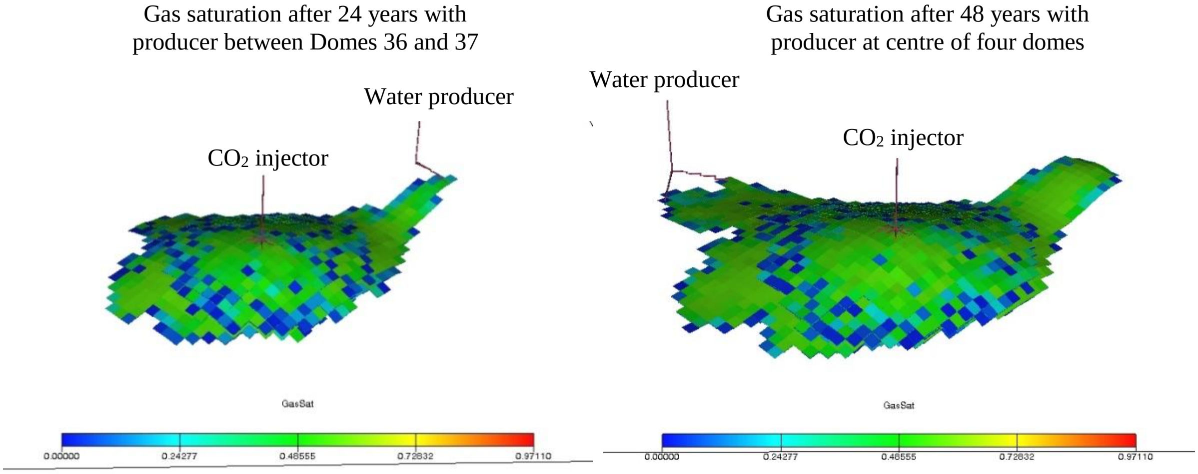


Figure 3-4 Gas saturation in Bunter model shows that CO_2 reaches a water producer located between Dome 36 and Dome 37 (left) after 24 years of injection, but it took nearly double that time (48 years) to reach the same location if the water producer was located at the bottom of the model (at the centre of the four domes) and attracted a significant proportion of the CO_2 to that direction, as shown in the right hand diagram.

3.2.2. Three injector-producer patterns

Various patterns of CO_2 injectors and water producers were investigated to identify the optimal configuration for various total injection rates. As was identified by PBD in a previous project, the pressure will increase quickly if the crest of the dome is surrounded by CO_2 injection wells on all sides; thus Scenario 1 in Figure 3-5 shows one scenario will all the injectors on one side, and the producers on the other side. When CO_2 reaches to the first line of producers, these are shut in and the second line of producers come into operation. The first line of producers are closer to the injectors and so can act more efficiently at the beginning of injection period. By the second stage, these brine producers can then be converted into CO_2 injectors for a high injection rate case, such as the 20 or 40 Mt/y case. In order to delay the time of CO_2 breakthrough, the water producers are perforated in different (lower) layers from the injectors.

Scenario 2 and Scenario 3 are used to identify whether locating the producers outside or inside the pattern of injectors best aids the reduction in pressure. Because of the limited space in the Bunter dome, these patterns are not very effective. Producers were shut down early because of CO_2 breakthrough, and ceased to function early in the period of injection. This raises the question of well spacing.

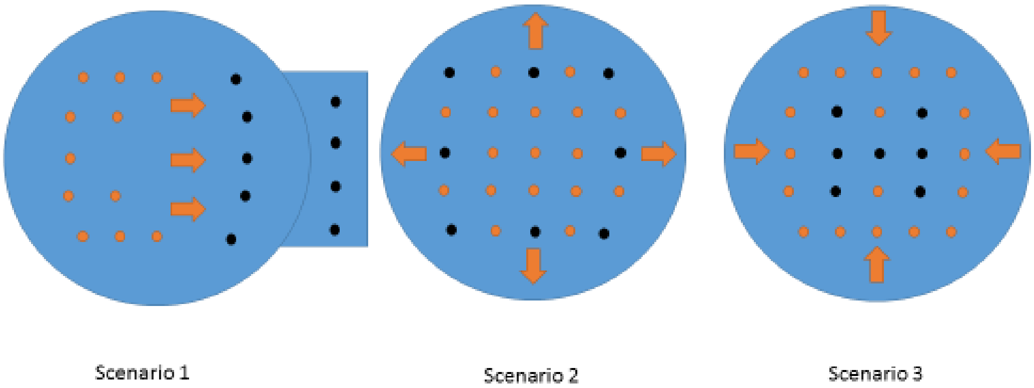


Figure 3-5 Three patterns tested for scenarios where the injection rate is > 15 Mt/y. Orange dots represent CO_2 injection wells, and black dots brine production wells.

4. Comparison of Water Production Case with Base Case

4.1. Forties model

4.1.1. Forties reference model (without water production)

From analysis of the simulation results in the previous sections, it was found that the injection capacity of the Forties formation is poor and becomes poorer with the increase of reservoir pressure due to CO_2 injection. Figure 4-1 shows how water production can help maintain the CO_2 injection rate constant. In the case without water production, the injection rate in well I2 reduced from 0.4 Mt/year (5×10^5 sm^3/d) at the beginning of injection (500 days) to 0.2 Mt/year (2.5×10^5 sm^3/d) after 20 years. The impact of water production was that the injection rate could be maintained near constant at 0.4 Mt/year for the 20 years.

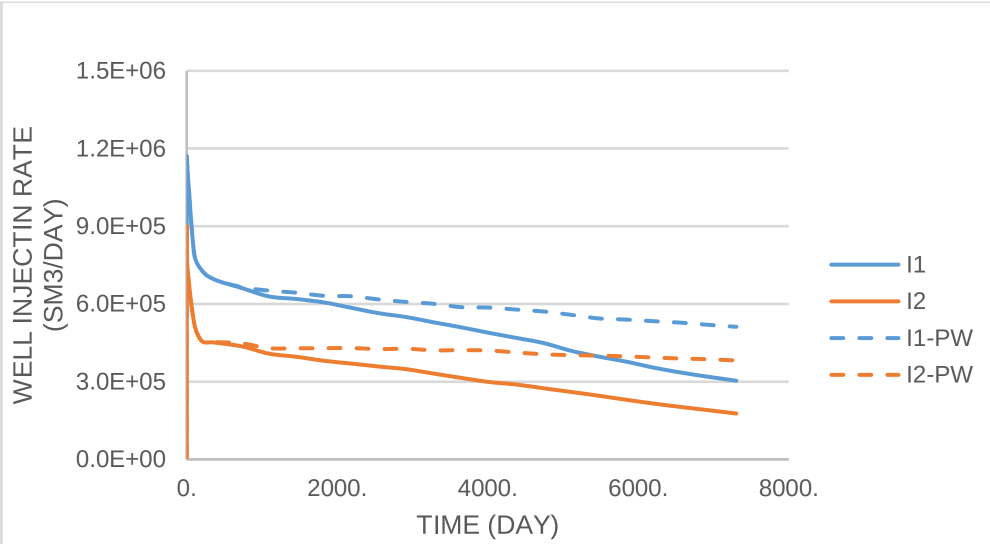


Figure 4-1 Well injection rate vs. time for a model with/without water production. The solid lines show the results with no water production. In each case, the injection rate reduces with time. The dashed lines show the results with production of water (PW); for some wells, such as I2 here, the production of water could help maintain the injection rate almost unchanged.

The reference case in the study is the case without water production. By changing the number of injectors and different durations of injection, whilst meeting the requested total injection rate, a matrix, such as the one used in the CO2Stored database, can be developed for injection capacity assessment. However, the tables in the database were created mainly based on an analytical model, not based on numerical simulation using a heterogeneous model with specific well control conditions.

The number of injectors required to maintain the proposed injection rate are listed in Table 4-1. Because of the low injection capacity in the Forties model the number of injectors required to meet a high total injection rate will be large. This had been reflected in the results of the ETI UKSAP project. It can be seen that the number of wells increases with field injection rate and also increases with injection duration, but, unlike the results in the CO2Stored database, is not proportional to the injection duration. The increase is greater with the increase of total rate, but lesser with injection duration.

While the well count in these calculations can reach large numbers for the very high injection rates, the point here is not the absolute number of wells, but how the storage capacity currently identified in CO2Stored (including the very large well count calculated in CO2Stored) can be altered by use of brine production wells. Any early project that uses brine production would likely target a system that requires fewer wells to begin with, and indeed these calculations are currently being repeated for a system in the Forties with higher absolute permeabilities which will require fewer wells.

One method to increase the injection capacity is to use horizontal wells. This method was also used in the PBD model even though that model had a higher average permeability compared with the HWU model. In this study horizontal completions were also considered. Injectors are perforated at the bottom of the well along the x or y direction, which enables the length of each well to increase to 400m.

Rate\ period	10 year	20 year	30 year	40 year
2	5	6	7	7
5	18	21	23	23
10	56	78	92	92
15	71	106	106	106
20	120	120	-	-
40	284	-	-	-

Table 4-1 Number of injectors required for each case in the Forties reference model (without water production).

4.1.2. Forties water production models

As shown in Figure 4-2 the red wells are producers and the white ones are injectors. 120 wells were located with well spacing 2400m (distance of 6 cells from column to column) in the X direction and 2000m in the Y direction (distance of 5 cells from row to row). The distance between a producer and an injector is 2332m.

Injectors are controlled by either individual well injection rate, which is 0.8 Mt/year in the Forties model, or well bottom hole pressure (lower than the allowed maximum pressure), which is calculated based on well depth and fracture pressure. Injectors were also controlled by a group injection rate, such as 2Mt/year, 5Mt/year, etc. At the same time, all of the injectors were controlled by an action. When the block pressure at the top of the reservoir reaches an allowable maximum pressure, all injectors were shut down. This means that injection will stop because of the risk of failure of the seal.

Producers were controlled by minimum bottom hole pressure (set to the initial pressure of the well). They are also controlled by the maximum production rate, i.e 16000 sm^3/d (100,000 bbl/d). Producers were also controlled by two other criteria mentioned in the previous section; one is a limit on production of gas phase CO_2, and the other is a limit on the production of liquid phase CO_2. Once any limit was exceeded for a producer, the producer would be shut in.

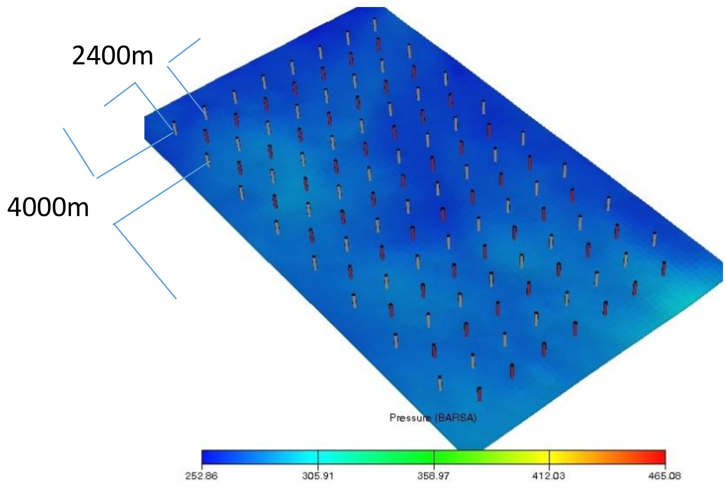


Figure 4-2 well locations in the Forties model, the red ones being the producers and the white ones the injectors. The number of wells used in each case is different and are listed in Table 4-2

Table 4-2 Number of injectors required for each case in the Forties model Scenario 1.

Rate\ period	10 year	20 year	30 year	40 year
2	5	6	7	7
5	18	21	23	23
10	56	74	88	88
15	64	89	99	99
20	113	113	-	-
40	284*	-	-	-

*the number is not from a simulation, but from correlation with other cases

Table 4-3 Number of injectors required for each case in Forties model Scenario 2.

Rate\ period	10 year	20 year	30 year	40 year
2	5	6	7	7
5	18	21	23	23
10	56	78	92	92
15	48	64	99	99
20	96	96	-	-
40	284*	-	-	-

*the number is not from a simulation, but from correlation with other cases

Because of the low injection capacity in the Forties model, a 5-spot well pattern was used, as shown in Figure 4-2, in order to control local pressure more efficiently and at the same time to delay gas breakthrough. The distance between each injector and corresponding producer is about 2330m. The producers are completed in the same layers as the injectors. All of the well completions in the water production study cases and reference cases are perforated for 400m (one cell) in only one high permeable layer in the horizontal direction.

Figure 4-3 shows the total CO_2 injection rate (FGIR) and field pressure (FPR) of the Forties model without water production for each injection rate scenario. The X axis in Figure 4-3 shows the injection duration (day), and a major grid line is 10 years (3650 days). The Y (left) axis shows field injection rate in sm^3/d; a major grid line is 10 Mt/y, and the Y (right) axis shows the field average pressure in bars. The numbers in each grid shows the number of injectors required for the period (10 years). In each case different numbers of injectors and producers were used. Well lists were set for producers and injectors for each 10-year period, i.e. the well lists were only changed every 10 years, if required.

Figure 4-3 shows the same content as Figure 4-2, but for cases with water production. The numbers following a '+' sign is the number of producers for the period. The top group of numbers show scenario 1, and the bottom show scenario 2. etc.. The number of injectors required for cases without/with water production scenario 1 and 2 are also listed in Table 4-1, Table 4-2 and Table 4-3, respectively.

Table 4-4 to Table 4-6 give the number of water producers required, water production starting time, and the maximum brine production rate per well for scenario 1, respectively. Table 4-7 to Table 4-9 gives the same results as for Table 4-3 to Table 4-5, but for scenario 2, in which the number of injectors and producers are different from that in scenario 1.

Table 4-4 Number of brine production wells in Forties model scenario 1.

Number of Brine Production Wells - with brine production (scenario 1)				
CO_2 Injection Rate (Mt/year)	**Injection Duration (yr)**			
	10	**20**	**30**	**40**
2	-	-	-	-
5	-	-	-	-
10	4	4	4	4
15	7	24	24	24
20	24	24	24	-
40	56	56	-	-

Table 4-5 Brine production start year after initial CO_2 injection in Forties model scenario 1

Brine Production Start Year - i.e. years after initial CO2 injection (scenario 1)				
CO_2 Injection Rate (Mt/year)	Injection Duration (yr)			
	10	20	30	40
2	-	-	-	-
5	-	-	-	-
10	2	5	5	5
15	0	0	0	0
20	0	0	0	-
40	0	0	-	-

Table 4-6 Brine production rate per well in Forties model scenario 1

Brine Production Rate per Well sm3/d - with brine production (scenario 1)				
CO_2 Injection Rate (Mt/year)	Injection Duration (yr)			
	10	20	30	40
2	0	0	0	0
5	0	0	0	0
10	2000	4000	4000	2800
15	4000	4000	4000	4000
20	4000	4000	4000	-
40	4000	4000	-	-

Table 4-7 Number of brine production wells in Forties model scenario 2

Number of Brine Production Wells - with brine production (scenario 2)				
CO_2 Injection Rate (Mt/year)	**Injection Duration (yr)**			
	10	**20**	**30**	**40**
2	-	-	-	-
5	-	-	-	-
10	4	4	4	4
15	7	24	24	24
20	24	24	24	
40	56	56		

Table 4-8 Brine production start year after initial CO_2 injection in Forties model scenario 2

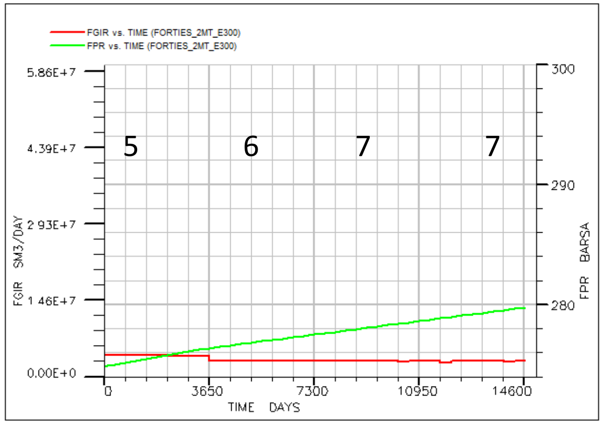
Brine Production Start Year - i.e. years after initial CO2 injection (scenario 2)				
CO_2 Injection Rate (Mt/year)	**Injection Duration (yr)**			
	10	**20**	**30**	**40**
2	-	-	-	-
5	-	-	-	-
10	2	5	5	5
15	0	0	0	0
20	0	0	0	-
40	0	0	-	-

Table 4-9 Brine production rate per well in Forties model scenario 2

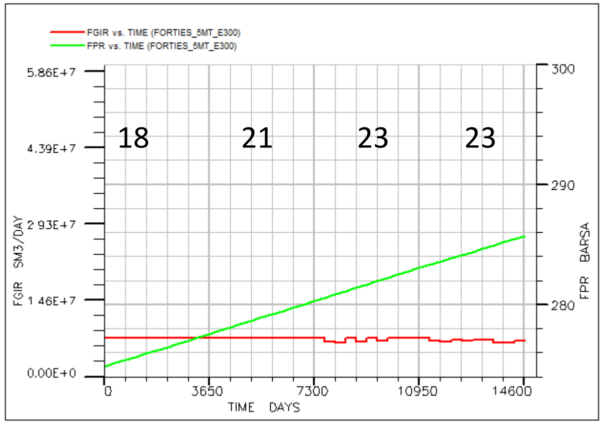
Brine Production Rate per Well sm3/d - with brine production (scenario 2)				
CO_2 Injection Rate (Mt/year)	Injection Duration (yr)			
	10	20	30	40
2	0	0	0	0
5	0	0	0	0
10	2000	4000	4000	3000
15	20000	30000	20000	2000
20	20000	30000	20000	-
40	40000	75000	-	-

Only the maximum brine production rates are listed in Table 4-6 and Table 4-9. The brine production rate history during CO_2 injection for each case for different scenarios can be found in Figure 4-5. This figure also shows the time when CO_2 breakthrough occurred by displaying the field produced CO_2 mole fraction change. It can be seen from the figure that when the limit of WXMF= $1x10^{-4}$ was reached in a producer, then the well was shut down and FWPR was reduced. Comparing Figure 4-4 with Figure 4-5, the effect of water production can be seen. When CO_2 breakthrough occurred the producer was shut down and the field pressure cannot be limited. As a consequence well bottom hole pressure increases quickly to its limit, and then the injection rate starts reducing. The effect of water production can also be seen by comparing Table 4-3 and Table 4-4. In the water production cases, by not increasing the total number of wells but changing the ratio of injectors to producers, the storage capacity can be increased for models with the injection rate of 15Mt/y and 20Mt/y. In these cases the total number of injectors reduced, but their injectivities were increased so that the total amount of CO_2 that can be stored was increased.

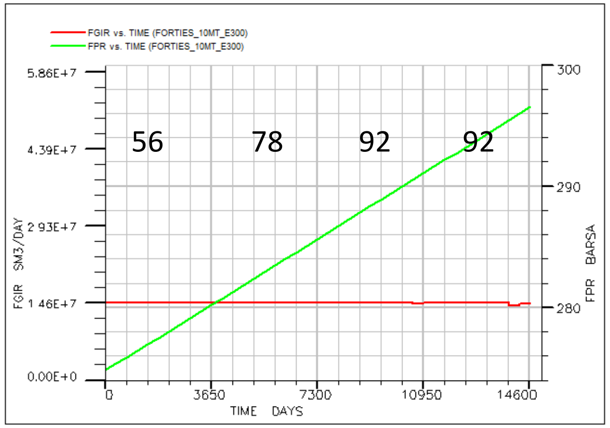
For the model with 40Mt/y injection rate the impact of water production appears less significant because of the well spacing. CO_2 breaks through so quickly that the producers had only a short operating life. In comparison, in the scenario in which fewer producers were used, water production and injection took longer. Therefore, a good combination of producers with injectors will optimise the storage capacity, although, as already indicated, this optimisation is not one of the aims of the current study.



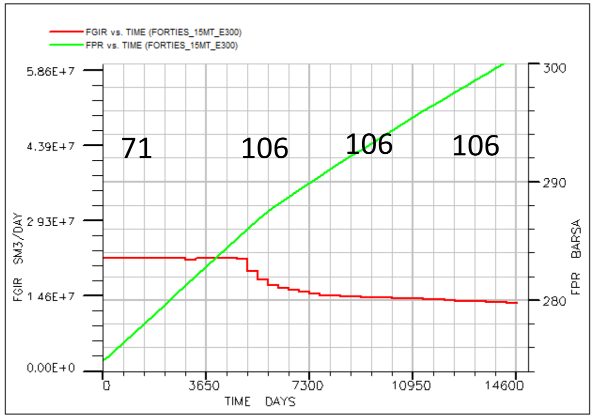
2Mt/year



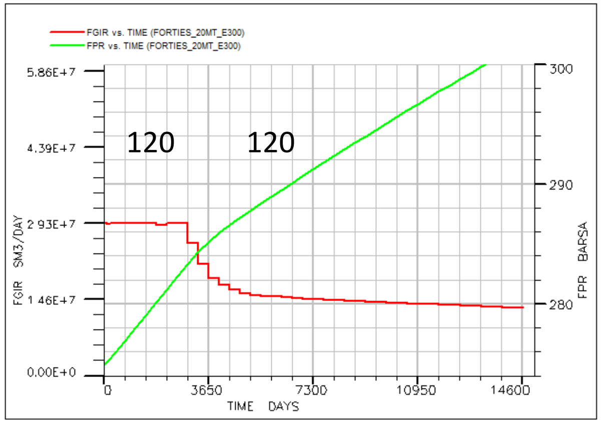
5Mt/year



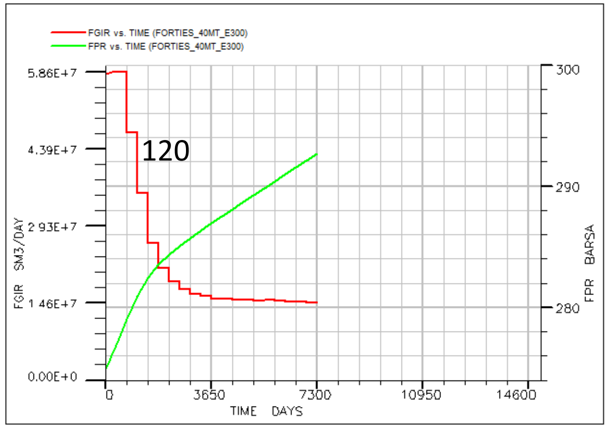
10Mt/year



15Mt/year

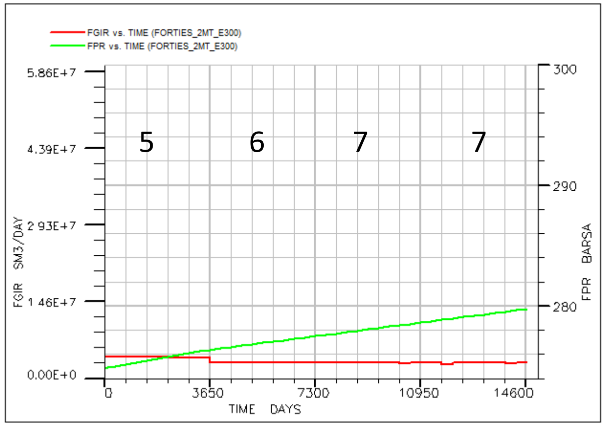


20Mt/year

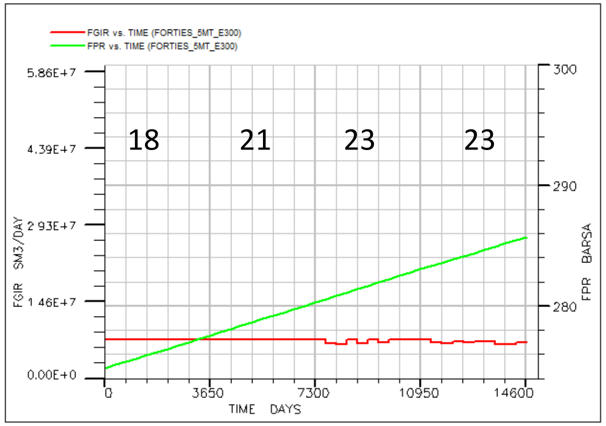


40Mt/year

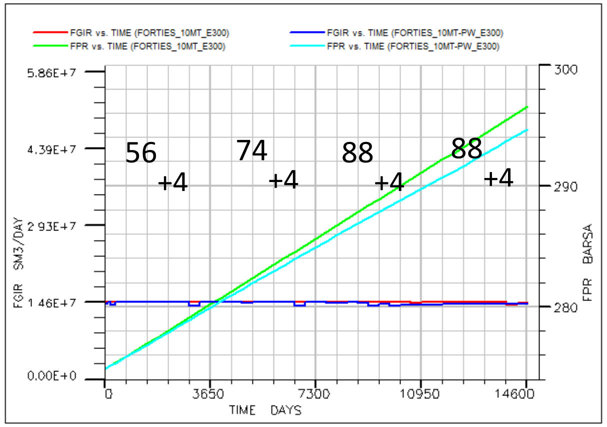
Figure 4-3 Forties model without water production. X - Injection duration (day), major grid lines for 10 years, Y (left) – field injection rate (sm^3/d), major grid lines for 10 Mt/y, Y (right) – field average pressure (bars), numbers in each time grid shows the number of injectors for the period



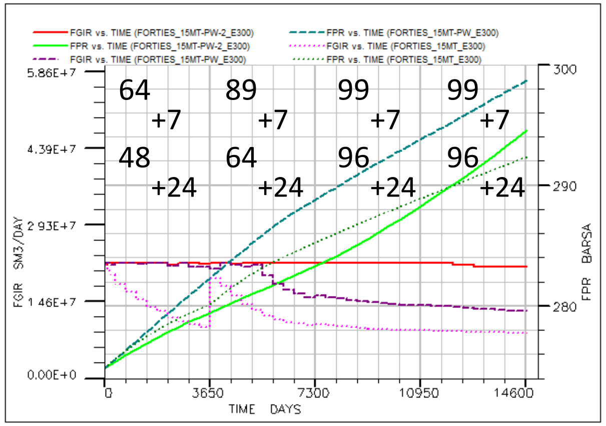
2Mt/year



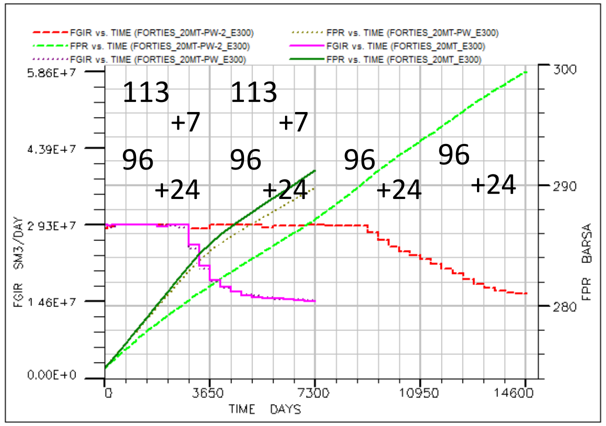
5Mt/year



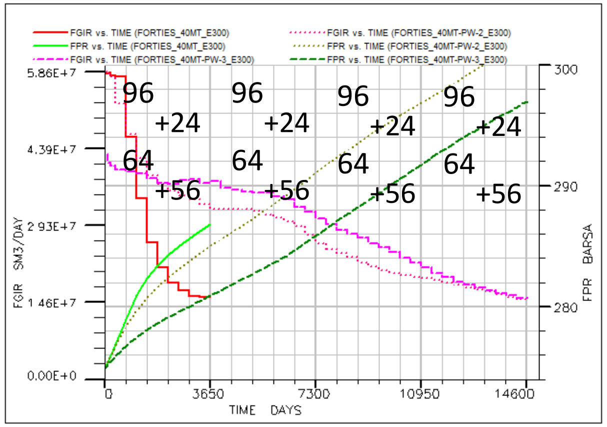
10Mt/year



15Mt/year

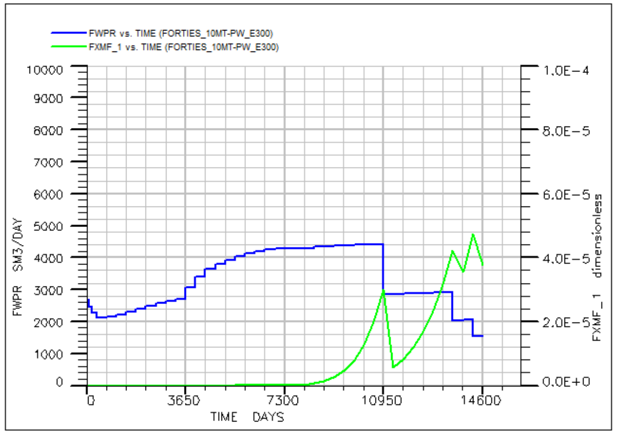


20Mt/year

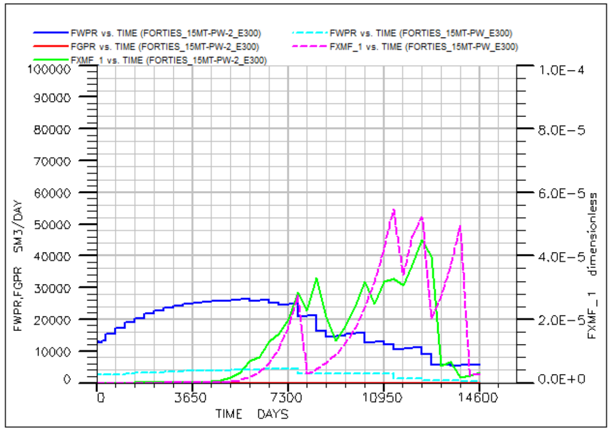


40Mt/year

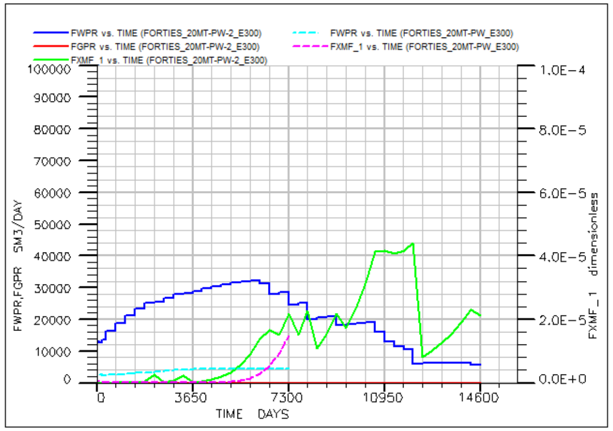
Figure 4-4 Forties model with water production. X - Injection duration (day), major grid lines for 10 years, Y (left) – field injection rate (sm^3/d), major grid lines for 10 Mt/y, Y (right) – field average pressure (bars), numbers in each time grid shows the number of injectors for the period, the number following + sign is the number of producers for the period. The top group of numbers show one scenario, the bottom show another one.



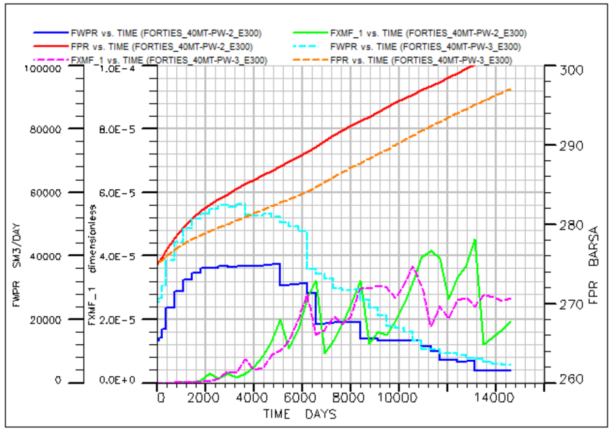
10Mt/year



15Mt/year



20Mt/year



40Mt/year

Figure 4-5 Forties model with water production. X - Injection duration (day), major grid lines for 10 years, Y (left) – field water production rate (sm^3/d), Y (right) – field total produced CO2 mole fraction (fraction). Because there was no need for water production in 2 Mt/y and 5 Mt/y cases, no plot is shown for these cases

4.1.3. Conclusions

The Forties system is sufficiently large that for lower CO_2 injection rates (order 2-5 Mt/y), brine production does not yield any increase in storage capacity, and therefore should not be considered. For an intermediate injection rate (10 Mt/y) the capacity of the system is such that initially there is no benefit from brine production. However, as pressure builds up over time, brine production becomes an increasingly useful method of increasing storage capacity. Above 15 Mt/y CO_2 injection rates, brine production should be considered from the outset. At very high injection rates, say 40 Mt/y, breakthrough of CO_2 at the production wells is so quick that the benefit of brine production is short lived. The well counts, and period and rate of brine production are data that are supplied for the economic analysis to determine whether or not the process is a viable means of increasing storage capacity and reducing overall costs.

4.2. Bunter model

4.2.1. Bunter reference model (without water production)

A similar methodology as the Forties modelling was applied using the Bunter model. Reference simulations were run first to find the number of wells required for each injection rate. The differences between the Forties and Bunter parameters, listed in Table 3-1, impact the application of the water production technique. Firstly, the Bunter model is of a dome filled structure with high permeability (k_{avg} = 150mD). Even Zone 4 has a similar pore volume to Forties, the main body Closure 36 in the geological model has limited volume which is determined by the spill point. The study needed to use a reference case that has a relatively high sweep efficiency, and a low pressure build-up at the crest. As mentioned, in a previous project it has been identified that setting injectors in a circle or too close to the crest can cause all wells to be shut in early.

As shown in Figure 4-6 several regions were set in the model. A cross-region flow rate was an output parameter to monitor how much CO_2 has flowed from R16 into the neighbouring regions. The final total amount of injected CO_2 depends on the time when the criterion is reached, but not the simulated injection duration. Because the parameter cannot be set as an action control parameter, the calculation was performed manually.

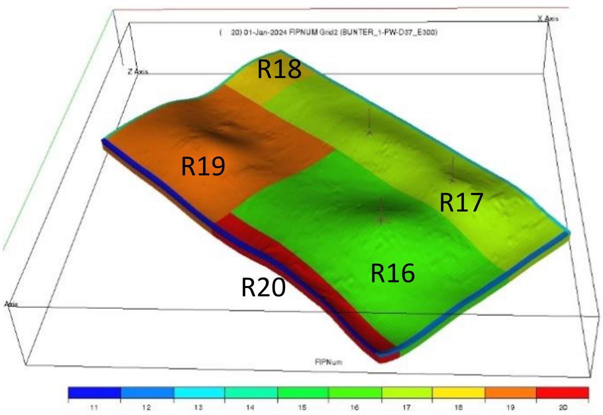


Figure 4-6 regions in Bunter model to set the boundary for Closure 36

Table 4-10 lists the number of injectors required for all cases without water production, and Figure 4-7 shows the field injection rate and average pressure during the injection period. Based on the calculation of pore volume in Closure 36 and the estimation of the storage capacity, the injection duration was set to 30 years for the 15Mt/y case, 20 years for the 20Mt/y case, and 10 years for the 40Mt/y case.

Table 4-10 The number of injectors required for each case.

Rate\ period	10 year	20 year	30 year	40 year
2	**1**	**1**	**1**	**1**
5	2	2	3	3
10	**4**	**4**	**5**	**6**
15	7	9	10	-
20	**9**	**10**	**-**	**-**
40	25	-	-	

4.2.2. Bunter water production models

Three scenarios, as described in Section 3.2.2, were used for the Bunter model. The difference is the direction of flow of CO_2, i.e. Scenario 1 - from left to right in the model, Scenario 2 - from the centre of the dome to the outside of the dome, and Scenario 3 – from the outside of the model to the centre of the model.

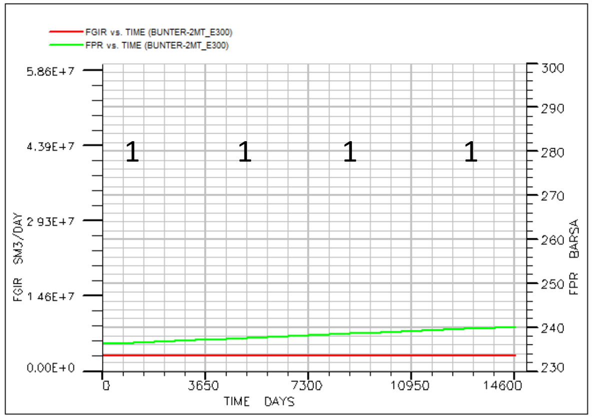
Table 4-11 lists the number of water producers, the starting time of production, and the maximum water production rate in each case. Because the results show that the CO_2 breaks through very quickly in the other two scenarios, water production in these patterns appears to be unsuitable for this model, which can also be seen from Figure 4-8.

Figure 4-8 shows the simulation results from the Bunter model cases with water production. The top three diagrams show the field gas injection rate (Y-left) and field pressure (Y-right) vs. time for 15, 20 and 40Mt/y cases. The bottom three diagrams show the field water production rate (Y-left) and field CO_2 produced in liquid phase (mole fraction) vs. time for injection rate of 15 Mt/y, 20 Mt/y, and 40 Mt/y. The number of wells is marked in each diagram, using the style injector+producter, and from the top row to the bottom row represents the numbers in scenario 1 to scenario 3. If only one scenario is considered, it has only one row for scenario 1. If there are three rows in the 40 Mt/y case, it means the numbers on the top is for scenario 1.

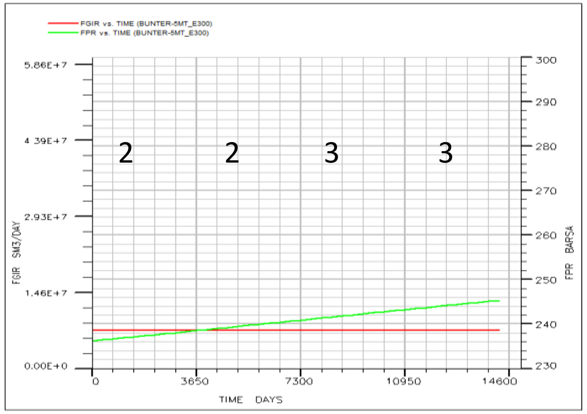
Table 4-11 Number of brine production wells in Bunter model scenario 1

Number of Brine Production Wells - with brine production (scenario 1)

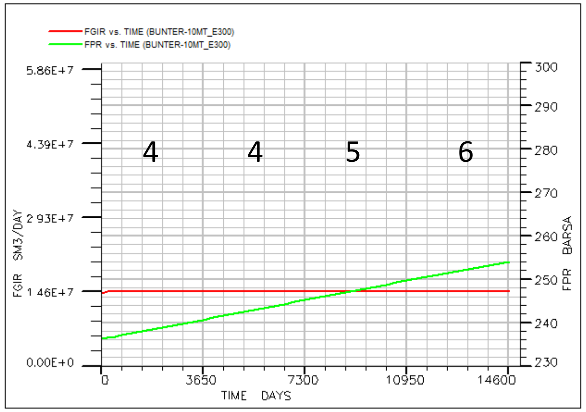
CO_2 Injection Rate (Mt/year)	**Injection Duration (yr)**			
	10	**20**	**30**	**40**
2	0	0	0	0
5	0	0	0	0
10	0	0	0	0
15	1	4	4	4
20	9	4	4	
40	8			



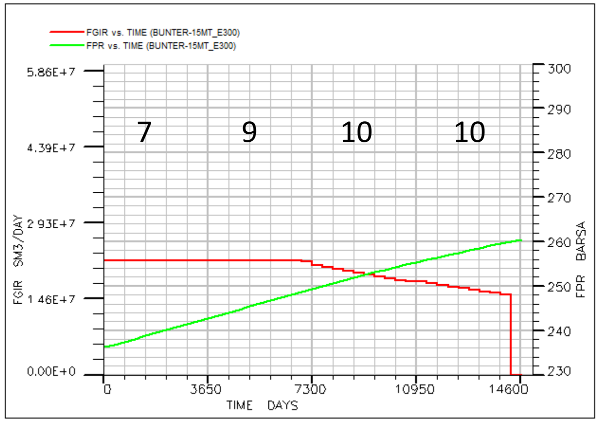
2Mt/year



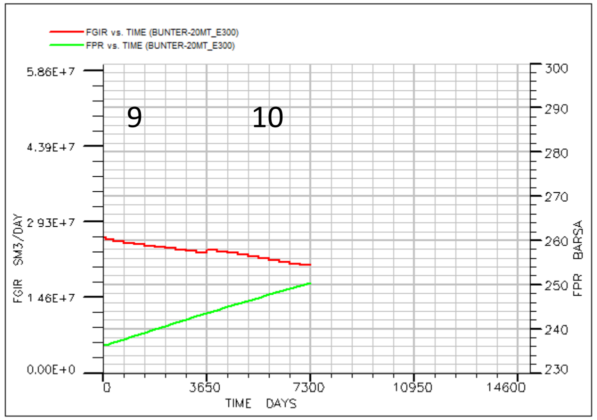
5Mt/year



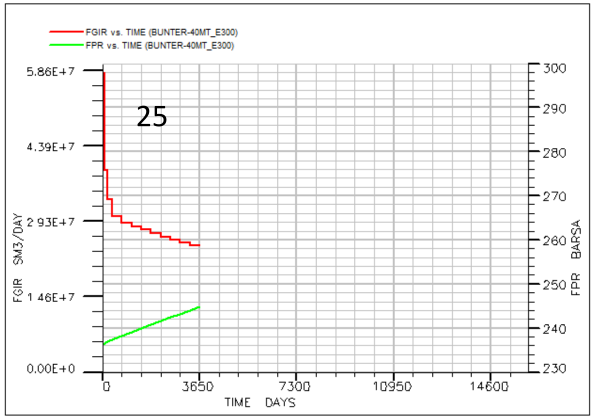
10Mt/year



15Mt/year

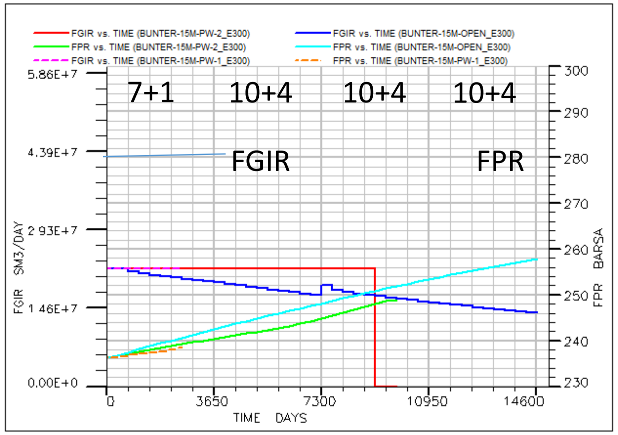


20Mt/year

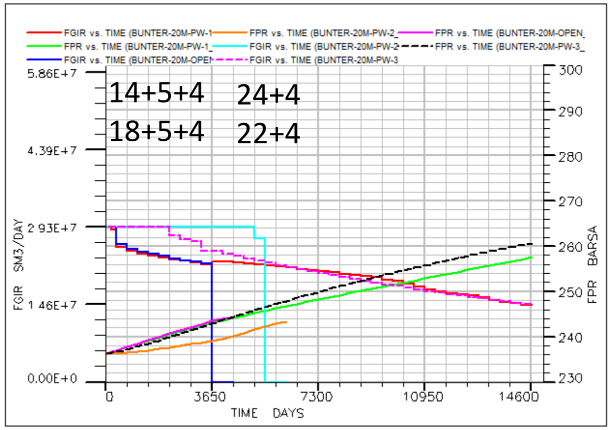


40Mt/year

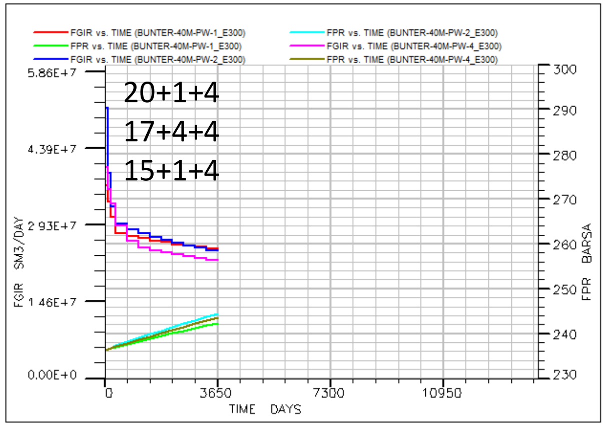
Figure 4-7 Bunter reference cases for CO_2 injection without water production.



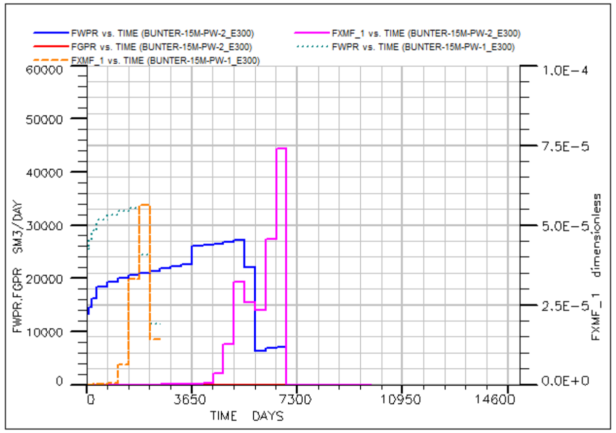
15 Mt/year



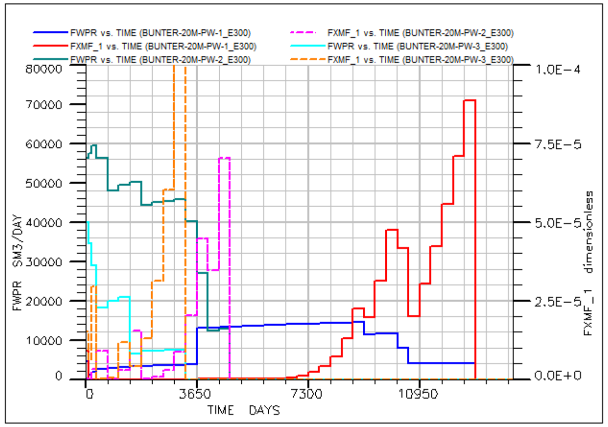
20 Mt/year



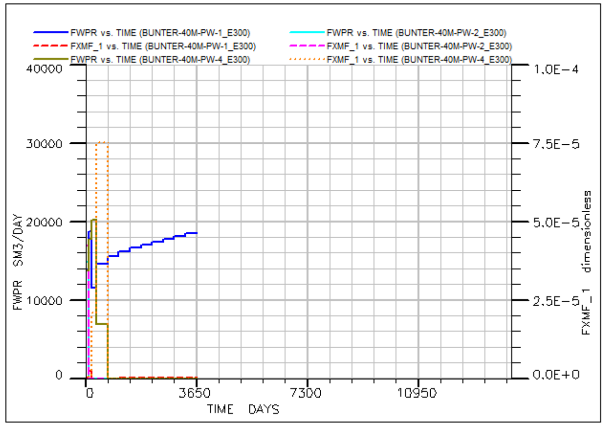
40 Mt/year



15 Mt/year



20 Mt/year



40 Mt/year

Figure 4-8 Bunter model cases with water production, top - field gas injection rate (Y-left) and field pressure (Y-right) vs. time; bottom – field water production rate (Y-left) and field CO_2 produced in liquid phase (mole fraction) vs. time for injection rate of 15Mt/y (left), 20Mt/y (middle) and 40 Mt/y (right).

4.2.4. Conclusions

As was the case for the Forties system, at lower CO_2 injection rates brine production yields no benefit. The nature of the Bunter aquifer, with higher permeabilities and dome structures results in higher injection rates being possible with no benefit from brine production – up to 15 Mt/y. Also, the higher permeabilities mean that even at these higher injection rates, fewer brine production wells are required to provide the required pressure management.

5. Hamilton Gas Field Reservoir Modelling

5.1. Background

Hamilton is a moderately sized UK gas field located in Block 110/13a of the East Irish Sea, just off the Lancashire coast, in 30 m of water. The field was discovered in 1990 and was projected to have a GIIP of 627 × 10^9 scf. Production commenced in 1997 via four gas producer wells, natural gas expansion being the drive mechanism, with limited aquifer water ingress. Hamilton was developed as part of the Liverpool Bay Integrated Development scheme, connected to the Douglas Complex along with the Douglas, Lennox and Hamilton North fields (Yaliz and Taylor, 2003).

The Hamilton field structure is a simple horst block about 10 km long by 3 km wide, orientated N-S and cut by minor E-W and N-S faults, non-sealing within the field. The crest of the structure at the reservoir is around 2300 ft TVDSS, with a GWC at 2910 ft TVDSS. The field had an initial pressure of 1404 psi at the reservoir crest.

5.2. Reference case without brine production

A reservoir simulation model of CO_2 injection into the depleted Hamilton gas field was supplied to HWU by the ETI. The model, developed by PBD, consisted of a suite of E300 data input files, which had been exported from a Petrel model and edited manually. The files were for a CO_2 injection simulation scenario of 5 Mt/year, and was designated the "reference" case with injection starting on 1st January 2026 into the predefined pressure and saturation state of the depleted field.

The reference case had CO_2 being injected via two pairs of wells in two stages. In the first stage CO_2 was injected in the sub-critical (low pressure) phase at a rate of 2.5 Mt/year per well, each well with appropriate well vertical flow performance (VFP) tables. These wells were designated INJ1_DEV and INJ2_DEV. Once the reservoir pressure had risen from a starting pressure of ~200 psi to ~1100 psi, the injection was switched to a new stage at super-critical conditions via the second pair of wells, at the same rate but with different VFP tables. These wells were designated INJ3_DEV and INJ4_DEV.

The reference case was run using the files as supplied. The first stage of CO_2 injection was observed to last 13.6 years and the second stage ceased after 24.8 years when the crestal block pressure in the model reached 1471 psi. During CO_2 injection 67.9 Mt had been injected in stage one and 123.9 Mt at the end of stage two. The simulation then continued for a further 1000 years, without further injection, to track the fate of the CO_2. All the injected CO_2 remained in the store, without migrating via any pathways.

5.3. Brine production scenarios

For the initial brine production scenarios, four water producers were set up on the periphery of the store – two wells on each of the lengthwise sides. These wells were vertical and penetrated the water bearing layers of the model, outwith and below the store, being completed in all layers of the model. These wells were designated P1_WAT, P2_WAT, P3_WAT and P4_WAT. The WBHP limit for each well was set depending on the depth of the reservoir top at the well location, and with a specified water production rate target. These constraints had the effect that water production only began when the reservoir pressure built up sufficiently for the wells to flow. Three versions of this model were run, with target brine production rates for each well of 10,000, 15,000 and 20,000 stb/d.

It might be questioned how such production rates could be maintained given the limited aquifer ingress and water production observed during the hydrocarbon production lifespan of the field.

However, as noted, this water production was only implemented when CO_2 injection had increased the reservoir pressure. During hydrocarbon gas production, any pressure reduction resulting from the offtake of gas would primarily result in expansion of the remaining gas. For every cubic foot of gas extracted, there would be some ingress of aquifer water, but not one cubic foot of water: most of the voidage created by the extraction of gas is taken up by expansion of remaining gas. (If the system were only filled with water, and one cubic foot of water were extracted, then ingress of aquifer water would be much more than in the gas production scenario – in fact it would approach one cubic foot of aquifer water ingress.) Thus there would be less drive mechanism for aquifer influx when the pore space is occupied by gaseous fluids on extraction of one unit (reservoir) volume of this gaseous fluid, regardless of the mobility or volume of the brine. During gaseos CO2 injection, the same happens in reverse. The resulting pressure increase results predominantly in compression of the gaseous phase, not so much in displacement of aquifer brine. However, once sufficient CO_2 had been injected that the CO_2 becomes supercritical, the compressibility of the non-aqueous phase would be much reduced, and thus the relative mobilities of CO_2 and water would become more important. Further injection of CO_2 would therefore result in greater displacement of brine should there be a pressure sink to provide a viscous drive for this displacement – the system no longer being governed primarily by compressibility, but now by compressibility *and* mobility effects.

The objective of brine production would thus not be to keep the non-aqueous phase in the gaseous state, but rather that once the CO_2 reaches dense phase, to provide a displacement process to prevent further significant rise in pressure.

Besides the constraint on the crestal block pressure terminating CO_2 injection, a new constraint was introduced that should the gas production in any producer exceeding 1 Mscf/d this would also terminate the CO_2 injection. The number of brine producers was then reduced to two wells with new locations selected between the previous wells, on either side of the store. These wells were designated P5_WAT and P6_WAT, their WBHP limits were set as for the previous wells and a brine production rate target of 40,000 stb/d was set for each well. A single well, P5_WAT was then used for brine production with a limit of 50,000 stb/d. The location of the wells is shown in Figure 5-1.

Finally two horizontal brine producers were set up, again on each lengthwise side of the store, their heel to toe trajectories parallel to the sides. These horizontal wells were designated H1_WAT and H2_WAT, with their wellheads at the same location as the previous P5_WAT and P6_WAT wells, respectively. Each horizontal well was completed in the aquifer in a layer near the base of the model in the water leg, over a length of 1 km (10 × 100 m cells). Again WBHP limit for the wells was set as above, and a brine production target of 40,000 stb/d specified. For all the scenarios described above, the CO_2 injection schedule was kept as the reference case i.e. 5 Mt/year total injection rate. A summary of the modelled scenarios is given in Table 5-1.

5.4. Containment constraint

The simulations performed above confirmed that the capacity of the Hamilton gas field as a CO_2 store was essentially limited by the characteristics of the geological structure as a trap, in that if more CO_2 were injected than could be contained by buoyancy in the trap, it would be displaced towards various local spill points, taking pathways to the adjoining formation – see Figure 5-2. An assessment of potential displacement rates in geological storage via various pathways – wellbore, faults, caprock etc. – is given in a recent publication (Jewell and Senior, 2012), and was used as the basis for setting a limit on this displacement, as shown in Figure 5-3. It should be noted that the model has limited extent, and therefore the acceptability of displacement of CO_2 away from the original hydrocarbon trap would depend on the definition of the storage complex, which might well have to consider a larger volume than modelled here.

In order to assess this displacement of CO_2, the model was reconfigured into five fluid-in place (FIP) regions. One FIP constituted the "approximate" cells of the original hydrocarbon trap, and the other four FIP regions, the remaining cells in SE, NE, NW and SW quadrants of the model, as shown in Figure 5-4. This configuration enabled the inter-region flows (store → SE, store → NE etc.) within the model to be monitored and the CO_2 displacement from the original hydrocarbon trap to be evaluated. The models run previously were rerun with these FIP regions. An inter-region displacement rate of 5 Mscf/d was chosen as the permitted limit at which the CO_2 injection would be terminated in practice and the store capacity evaluated for these rerun cases. This represents the conservative assumption that significant CO_2 displacement away from the original trap would not be acceptable.

The model was also run with the CO_2 injection rate reduced in the wells. Initially this was set at 0.35 Mt/year for each well i.e. total injection rate 0.7 Mt/year. For the change over time from sub-critical to super-critical wells, the reference case field pressure response was inspected and it was seen that this occurred when the pressure reached 1100 psi. However, at the above rate the field pressure failed to attain this pressure after 60 years injection. The injection rate in each well was then increased to 0.5 Mt/year i.e. total injection rate 1.0 Mt/year. Again, after 60 years injection, the field pressure still failed to reach 1100 psi.

The injection rate for each well was further increased to 1.0 Mt/year (2.0 Mt/year total) and the field pressure was seen to reach the supercritical level after 33 years injection. This model was then run without and with brine production, the latter scenario with water production via the four wells P1_WAT, P2_WAT, P3_WAT and P4_WAT at a rate of 10,000 stb/d.

5.5. Results

For the modelled reference case (no brine production) of CO_2 injection into the gas field at an injection rate of 5 Mt/year enabled 67.9 Mt to be stored at the end of the sub-critical period after 13.6 years, and ultimately 123.9 Mt to be stored in the supercritical period which lasted up to 24.8 years from the start of injection, before the fracture pressure limit at the reservoir crest was reached. The results of the simulated scenarios carried out are presented in Table 5-2 and further shown graphically to aid comparison in Figure 5-5.

With four brine production wells, with increasing brine production rates from 10,000 to 20,000 stb/d the rate of increase in the field pressure (and corresponding crestal pressure) declined and the injection duration was increased, before the crestal pressure reached its limit. Correspondingly more CO_2 could be injected. However for the 20,000 stb/d case, the limit on injection duration was not the crestal pressure, but the gas production rate in one of the brine producers, due to displacement from the hydrocarbon trap. When this case was rerun with the inter-region flows monitored the injection duration was further reduced when a maximum displacement rate of 5 Mscf/d was imposed. For this case the injection duration was 30.1 years and a total of 150.5 Mt CO_2 was stored. This represents an enhancement in storage capacity of 21.5% over the original reference case (no brine production) for the 5 Mt/year injection rate capacity.

For the cases of just two and then a single brine producer, with brine production rates of 40,000 stb/d there was very little difference between the response of the system, and no potential increase in storage capacity over the cases with four wells. For the case of two horizontal wells each producing at 50,000 stb/d there was a significant increase in the injection duration before the crestal pressure limit was reached and corresponding increase in CO_2 injected over the reference case. However, when examining the gas saturation distribution throughout the model it was seen that a significant amount of CO_2 had migrated outwith the store. Re-running the model and imposing a displacement limit of 5 Mscf/d, the injection duration was reduced 27.7 years and the total CO_2 injected to 138.3 Mt.

For the final scenarios with a reduced injection rate of 2 Mt/year (1 Mt/year each well) the case of no brine production enabled 66.0 Mt to be stored at the end of the sub-critical period after 33.0 years, and ultimately 123.9 Mt to be stored in the supercritical period which lasted up to 61.9 years from the start of injection, before the fracture pressure limit at the reservoir crest was reached. These results confirmed the "fixed capacity" of the store, independent of injection rate, without brine production. With brine production the rate of increase of field pressure (and corresponding crestal pressure) is very slow and hence the injection period is very long at 89.9 years and does not reach the limit. In this case the constraint is gas production in a brine producer. If the constraint is then taken as the inter-region flow, the injection duration is reduced to 78.7 years. In the latter case the total CO_2 injected is 157.4 Mt. Although this capacity is a significant enhancement of the original reference case (no brine production) 5 Mt/year injection rate capacity, representing a 27% increase, it is achieved over a very long injection period and with considerable volumes of produced water.

5.6. Conclusions

The CO_2 storage capacity of the depleted Hamilton gas field can be enhanced by brine production and further enhanced by low injection rates, consistent with maintaining the store pressure above that required for super-criticality of the injected CO_2. The predicted capacity is constrained by the permitted CO_2 flow rates, either in the brine production wells or migration to parts of the formations outwith the original area of the hydrocarbon trap. Given this constraint, the potential for extension of life as a store is significant. It is of particular note that the opportunity to use brine production to enhance storage capacity is greatest during the second half of the injection period, and hence there will be a deferment of associated costs.

Case I/D	Brine production	CO_2 *Injection wells* Number of wells	Injection rate/well Mt/year	*Brine Production wells* Number of wells Well names	WBHP target psia	Production rate limit stb/d	Simulation control
REF_CASE	NO	2 (each period)	2.5	–	–	–	BPR 24,43,2, > 1471 psia
CASE00	YES	2 (each period)	2.5	4 P1/P4_WAT	1300 – 1500	10000	BPR 24,43,2 > 1471 psia OR any prod. WGPR > 1 Mscf/d
...R							...OR any RGFR > 5 Mscf/d (by inspection)
CASE02	YES	2 (each period)	2.5	4 P1/P4_WAT	1300 – 1500	15000	BPR 24,43,2 > 1471 psia OR any prod. WGPR > 1 Mscf/d
...R							...OR any RGFR > 5 Mscf/d (by inspection)
CASE01	YES	2 (each period)	2.5	4 P1/P4_WAT	1300 – 1500	20000	BPR 24,43,2 > 1471 psia OR any prod. WGPR > 1 Mscf/d
...R							...OR any RGFR > 5 Mscf/d (by inspection)
CASE03	YES	2 (each period)	2.5	2 P5/P6_WAT	1400 – 1500	40000	BPR 24,43,2 > 1471 psia OR any prod. WGPR > 1 Mscf/d
CASE04	YES	2 (each period)	2.5	1 P5_WAT	1500	50000	BPR 24,43,2 > 1471 psia OR any prod. WGPR > 1 Mscf/d
CASE05	YES	2 (each period)	2.5	2 HW1/HW2_WAT	1400 – 1500	40000	BPR 24,43,2 > 1471 psia OR any prod. WGPR > 1 Mscf/d
...R							...OR any RGFR > 5 Mscf/d (by inspection)
CASE07	NO	2 (each period)	1	–	–	–	BPR 24,43,2, > 1471 psia
CASE08	YES	2 (each period)	1	4 P1/P4_WAT	1300 – 1500	10000	BPR 24,43,2 > 1471 psia OR any prod. WGPR > 1 Mscf/d
...R							...OR any RGFR > 5 Mscf/d (by inspection)
CASE09	NO	2 (each period)	0.35 0.5	–	–	–	BPR 24,43,2, > 1471 psia

Table 5-1. Modelled scenarios

Case I/D	Injection duration @ end period 1 years	Injection duration @ end period 2 years	Total CO_2 injected @ end period 1 Mt	Total CO_2 injected @ end period 2 Mt	Total brine produced @ end period 1 stb × 10^6	Total brine produced @ end period 2 stb × 10^6	Remarks
REF_CASE	13.6	24.8	67.9	123.9	–	–	
CASE00	13.6	29.7	67.9	148.5	1.8	207.4	
...R	13.6	29.7	67.9	148.5	1.8	207.4	Inter-regional flows do not limit injection duration before pressure limit reached
CASE02	13.6	33.7	67.9	168.3	1.8	374.3	Terminated after more than 100 hrs – convergence difficulties
...R	13.6	33.7	67.9	168.3	1.8	374.3	Inter-regional flows do not limit injection duration before pressure limit reached
CASE01	13.6	34.6	67.9	172.9	1.8	488.2	
...R	13.6	30.1	67.9	150.5	1.8	357.5	Inter-regional flows limit injection duration. End of period 2 determined by inspection
CASE03	13.6	27.0	67.9	134.9	0.0	93.3	
CASE04	13.6	26.9	67.9	134.6	0.0	90.5	
CASE05	13.6	40.2	67.9	200.8	10.9	647.5	No "displacment" limit
...R	13.6	27.7	67.9	138.3	10.9	267.0	
CASE07	33.0	61.9	66.0	123.9	–	–	
CASE08	33.0	89.9	66.0	179.8	4.2	695.8	
...R		78.7		157.4		532.2	
CASE09	–	–	–	–	–	–	Field pressure build-up inadequate for CO_2 super-criticality

Table 5-2. Simulation results

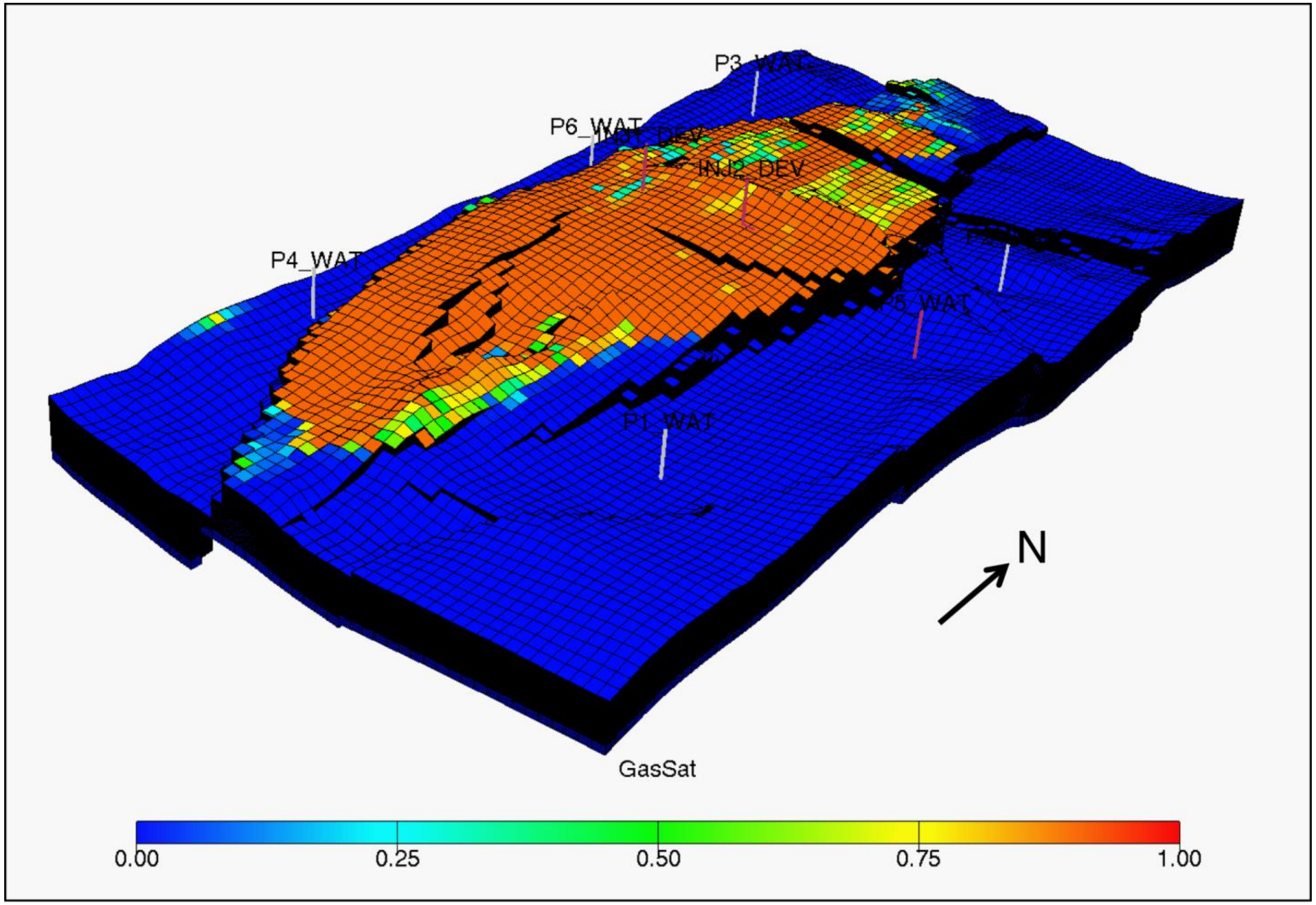


Figure 5-1. General view of model showing initial gas saturation at the start of CO_2 injection and well locations.

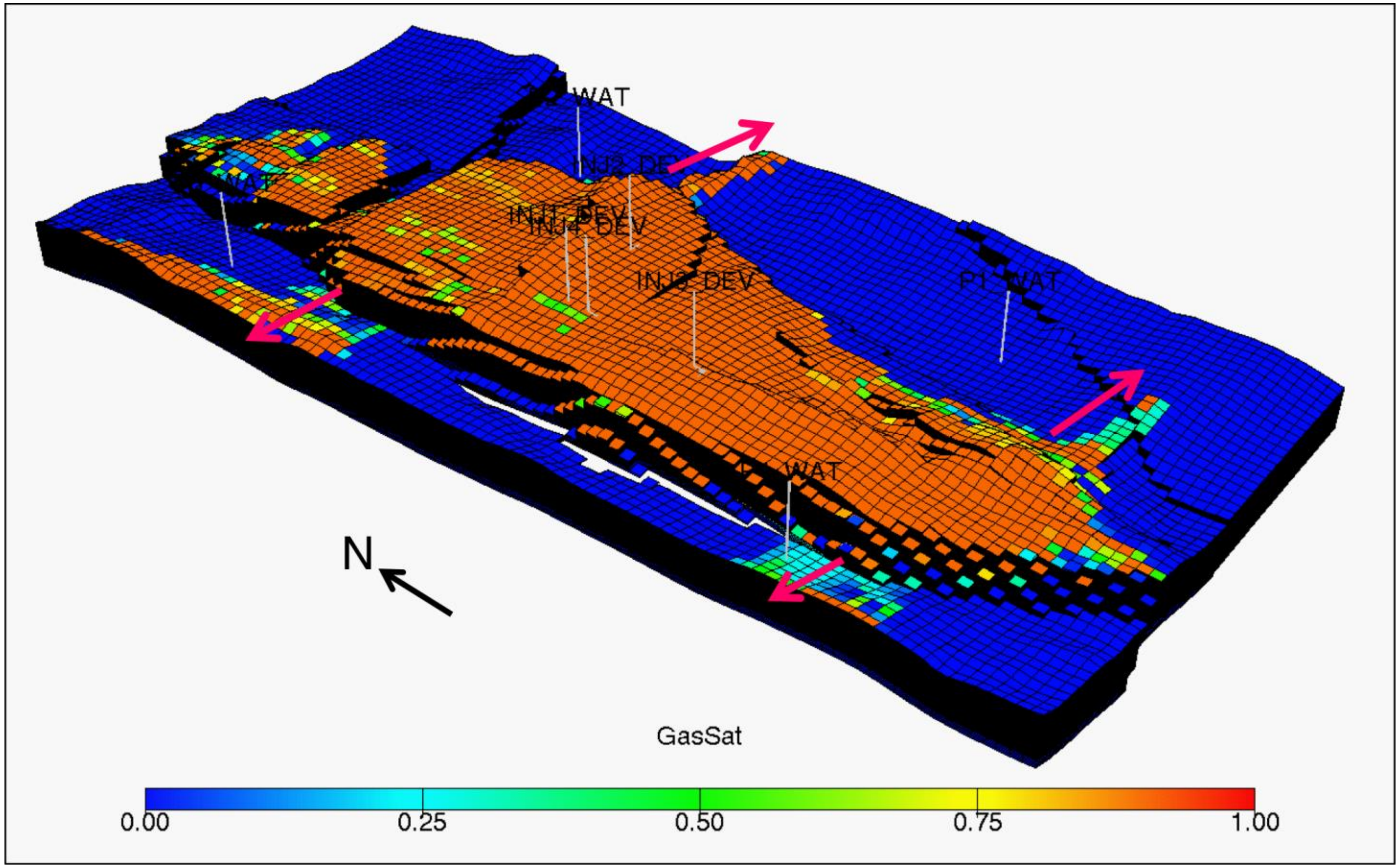


Figure 5-2. CO_2 displacement pathways from store (indicated by magenta coloured arrows).

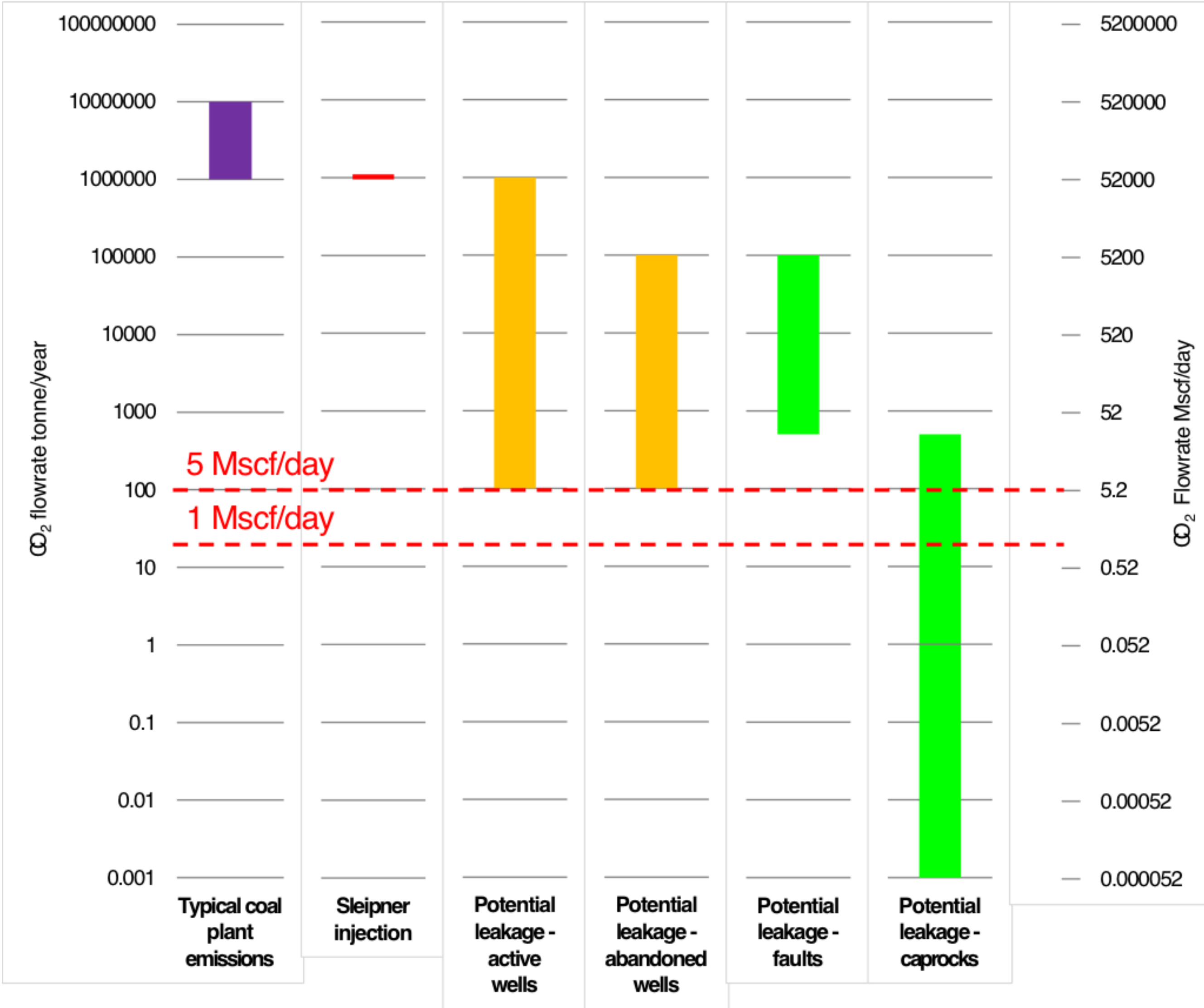


Figure 5-3. Range of CO_2 flow rates relevant to typical CCS processes.

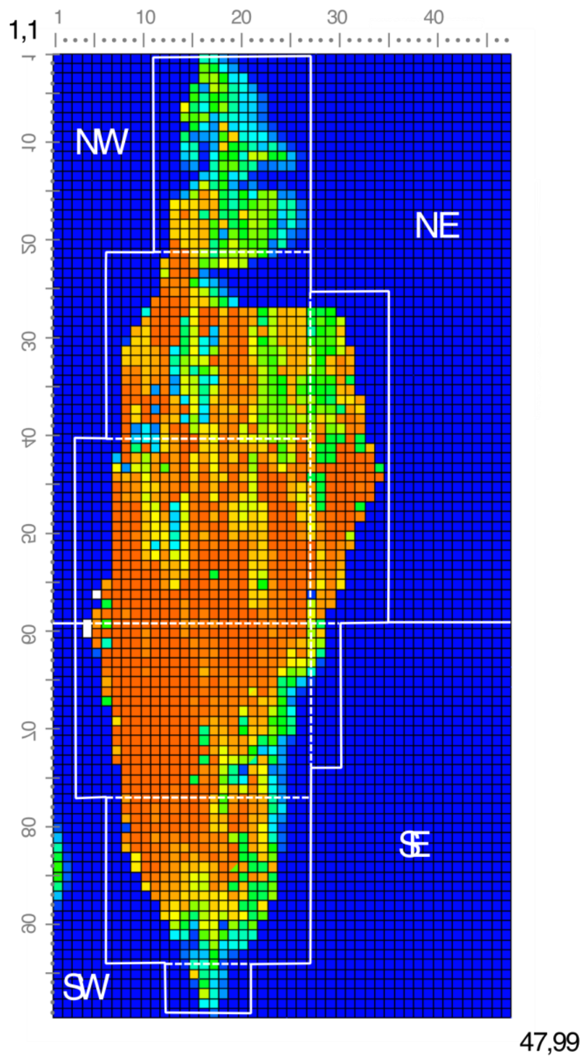


Figure 5-4. Fluid in place regions used to track inter-region flows.

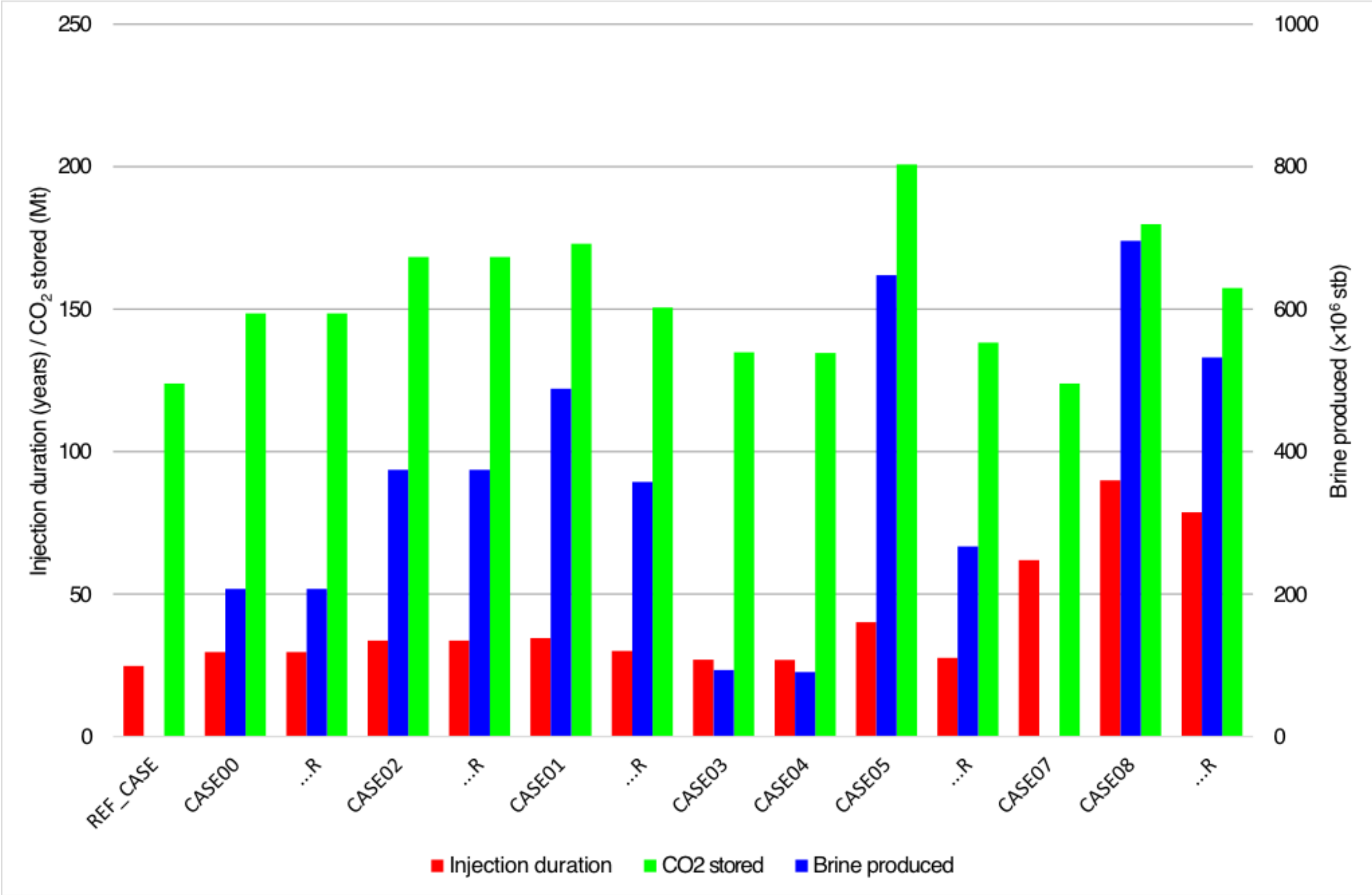


Figure 5-5. Summary of modelling results.

6. North Sea Oil Field Reservoir Modelling

6.1. Background

A reservoir simulation full field model (FFM) of a North Sea oil field had been previously provided to HWU by the operator, as part of a joint industry project (JIP) to investigate the techno-economic aspects of CO_2 enhanced oil recovery, in conjunction with carbon capture and storage (SCCS, 2015).

The field is a high net-to-gross deep-marine turbidite system with good reservoir permeability. The reservoir has minimal faulting, but shales can act as regional barriers to vertical flow. The field contains an under-saturated high °API oil, and has been developed with reservoir pressure support by down-dip water injection. The oil and water properties and good vertical relief of 1,200 ft result in a very efficient water flood. Gas injection EOR is being considered as an option to help maximise economic recovery from the field, by mobilising water-flood residual oil and contacting areas un-swept by the water-flood.

The FFM undergoing water-flood supported oil production had been provided as input data files for two E100 black oil simulations:

- a simulation history matched to observed production and injection rates from the start of production for 2072 days (5 years 8 months)
- a predictive simulation restarting from the end of the above, for a further ~20 years water-flood production.

The history matched black oil simulation was initially converted to an E300 compositional simulation using a 6 component fluid model, which was provided along with the FFM data. In this preliminary fluid model CO_2 was lumped with ethane as one of the components and as such was not suitable for CO_2-EOR studies. However, use of this preliminary fluid model enabled the conversion of the majority of black oil input data to appropriate compositional data.

Converting the black oil data to compositional data is not a straight-forward process because of differences in the interpretation of some input data keywords between the two programs. Whilst there are obvious parts of the data that need to be changed completely e.g. the fluid properties, some individual keywords have slight variations within their syntax and interpretation, depending on the program being used. Also for this particular FFM as there was no gas phase present in the black oil simulation, and because the compositional simulation assumes gas is present, dummy gas saturation function data were required. These modifications were carried out by manual editing of the data files, as it was not possible to import the complete dataset into the Petrel software, from which the model originated.

Subsequently a six component fluid compositional model with a separate CO_2 component was provided by the operator, and this was incorporated into the FFM. Subsidiary calculations were made using this data in a "slim-tube" simulation model to determine the minimum miscibility pressure (MMP) of the fluid. The MMP for the fluid determined by this method was 2970 psi.

6.2. Simulations

The simulations carried out with the model for this project envisaged CO_2 injection with the existing (up-dip) oil producers open and producing liquids i.e. co-produced oil and water, and after breakthrough, CO_2 gas. The scenarios were all carried out with a total CO_2 injection rate of 5 Mt/year, distributed in the injectors. The individual well injection rates were apportioned pro-rata depending on the water injection rates used in the original injectors, and the thickness of net formation penetrated in the case of new injectors. In all cases CO_2 injection commenced 15 years after the start of oil production in the field. The simulations were set up as restarts, following the initial history-matched water-flood phase and a further 9 years 4 months predictive extended water-flood. The simulations were all run for a 20 year CO_2 injection duration.

For the initial case the existing (water) injectors were utilised for CO_2 injection. Two further cases with new down-dip injectors were then set up. The new injectors were each a set of six vertical wells located in a line along the periphery of the field, in the down-dip water column. The first set were designated wells I1_CO2 to I6_CO2 and the second set wells I7_CO2 to I12_CO2, further down-dip again from the former. The injectors were spread along the periphery of the field in such a way that the injected CO_2 migrated up-dip to interact with the trapped oil, sweeping it to the existing producers. The first set of new injectors was approximately 1 km away from the existing injectors and the second set a further 1 km down-dip from the former. It should perhaps be noted that the original water injectors were more clustered together in groups, rather than distributed in a line as were the new injectors.

A further case was modelled whereby CO_2 was injected in the most down-dip set of new injectors, but water was also injected at a reduced rate in the original water-flood injectors. The objective of this scenario was to limit the migration of the CO_2 towards the production wells.

6.3. Results

The North Sea oil field is not operated here as a conventional store in a depleted hydrocarbon field, in that it is still producing oil as CO_2 is injected. Also, CO_2 will be co-produced with the liquid (oil and water) in the producers. Moving the CO_2 injectors down-dip delays the break-through of the gas in significant volumes in the producers. For CO_2 injection in the original (water) injectors this occurs ~1.5 years after injection commences. For the first set of new down-dip injectors, break-through occurs ~2.5 years after injection commences and for the second set of down-dip injectors breakthrough is extended to just over 3 years. The build-up of CO_2 production rate in these cases is correspondingly delayed. In the early 2 – 3 years after breakthrough, the build-up in production rate is more rapid for injection in the original injectors, these being closest to the producers.

Partial injection of water (via the original water-flood injectors) with CO_2 injected in the most down-dip set of new injectors slightly delays breakthrough, but the CO_2 production rate build-up is not significantly different from the other cases.

With increasing break-through time (and fixed CO_2 injection rate) the net amount of CO_2 stored at a given time, is correspondingly increased.

As regards oil recovery, there is only a small difference (less than 1%) depending on the CO_2 location of the injectors. It is higher in the cases of CO_2 injection than water injection. However, there is a more significant increase (~5%) for the case of CO_2 injection with some water injection. These results are illustrated in Figure 6-1.

6.4. Conclusions

In the case of the North Sea oil field studied, water injection can be partially replaced by CO_2 injection, and despite CO_2 breakthrough at the producers (and hence a requirement to recycle) a net amount of 54 Mt of CO_2 can be stored over a 20 year period, whilst increasing the oil recovery factor from 54% under pure water flooding in that same time period to over 59%, and reducing the requirement for water injection (with a modest reduction in water production also). The improvement in oil recovery may be attributed to microscopic (reduction in residual oil saturation in contacted zones) and macroscopic (better sweep efficiency) mechanisms. The prime interest in this study is, however, the potential to use CO_2 injection deep into the aquifer to at least partially replace water injection, here *reduced* water injection having a similar impact on storage potential to water production considered in the other cases studied.

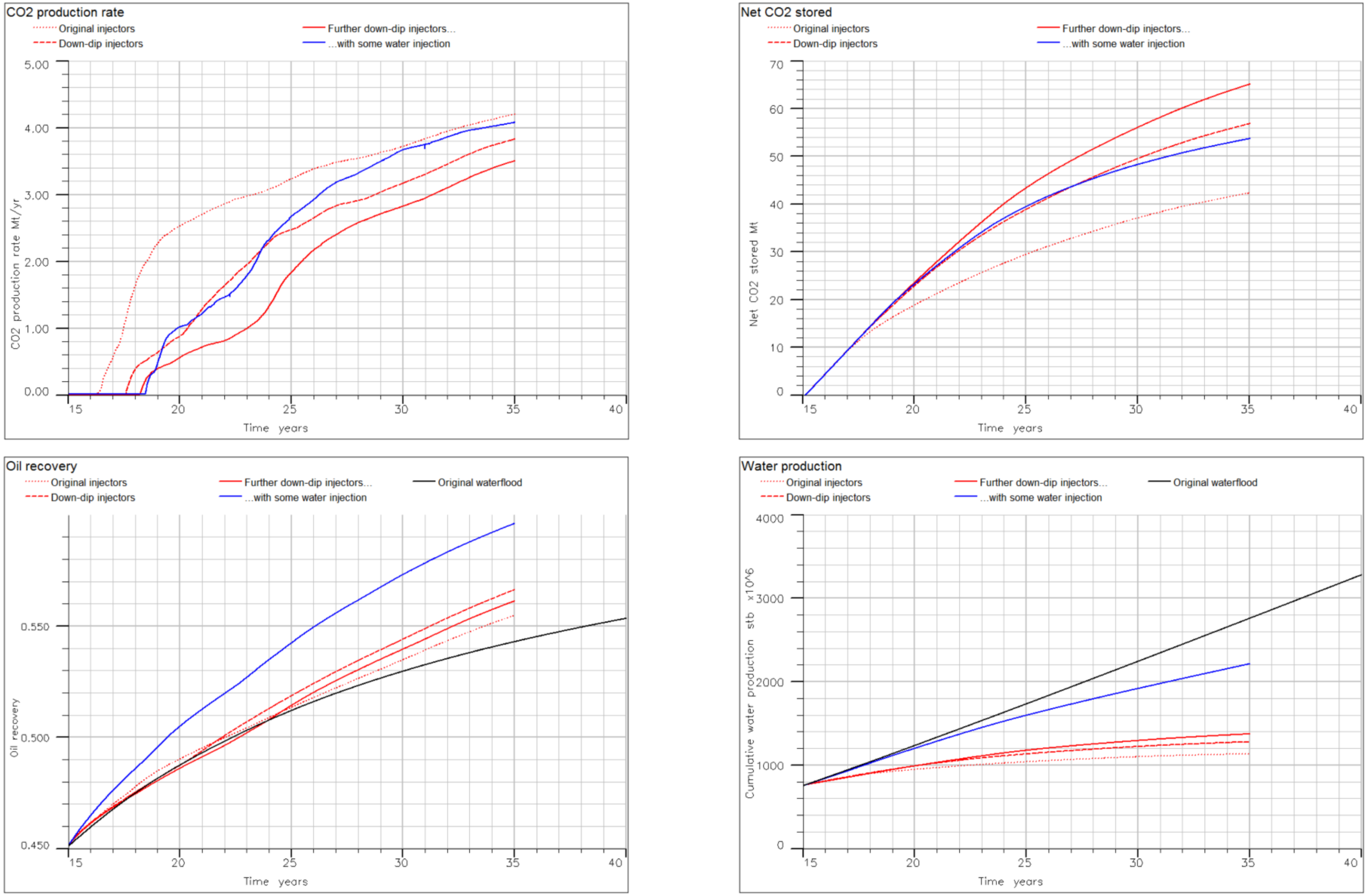


Figure 6-1. Comparative plots of simulation results for the North Sea oil field with CO_2 injectors in different locations.

7. Synthetic Steeply Dipping System

7.1. Background

The effectiveness of brine production wells in increasing CO_2 storage capacity is a function of various factors:

1. The extent to which CO_2 injection capacity is limited by pressure;
2. The distance between the CO_2 injection wells and the brine production wells;
3. The permeability of the rock in the intervening formation; and
4. The dip angle between CO_2 injectors and brine producers.

The maximum allowed pressure will be determined by the pressure at which the rock will fail, potentially leading to CO_2 leakage occurring. The pressure in and immediately around the CO_2 injection wells itself will be determined by the pressure of the surrounding formation (including the impact of depth), the rate of CO_2 injection, the length of the completed interval of the well and the permeability of the near well formation, amongst other factors.

For a brine production well to provide effective pressure relief, it must be close enough to the CO_2 injection well that the pressure depletion caused by the production well impacts the pressure in and around the CO_2 injection well. The lower the formation permeability, the closer the wells will need to be located for there to be a pressure benefit observable at the CO_2 injection well. However, this must be counterbalanced by the need to avoid breakthrough of the injected CO_2 at the brine production well, since this would necessitate potentially expensive separation of CO_2 out of the produced brine stream, followed by reinjection. It might also have corrosion, scaling and hydrate formation implications for the brine production well.

7.2. Model

A system with a steeply dipping top structure would allow opportunity for gravity stable CO_2 injection with brine production downdip. The density difference between CO_2 and brine would lead to buoyancy effects that would displace the injected CO_2 away from the brine production wells until the intervening pore space were filled with CO_2. However, consideration would need to be given to the dissolution of the CO_2 in the aquifer brine, which tends to increase the density of the brine relative to its native state, and thus CO_2 dissolved in brine will tend to be displaced downdip. However, such displacement processes tend to be slow, and so there will be a window of opportunity to inject CO_2 updip, with a brine production well placed close enough that significant pressure relief can be provided without CO_2 breaking through to the brine producer, either as a free phase, or dissolved in brine.

A synthetic sector model has been developed to test these issues, and to date has been used to assess impact of setting the allowed maximum pressure increase to a high value (ΔP = 63,000 kPa), or to a low value (ΔP = 7,600 kPa). To be clear, ΔP is the change in bottom hole pressure (BHP) during the injection period: i.e current BHP – initial BHP, referred to as pressure buildup in the figures below. Well spacing has been tested by considering a distant brine producer 7.2 km away, and comparing the impact of having a close brine producer 3.6 km away from the CO_2 injection well instead.

7.3. Results

Figure 7-1 shows the permeability distribution of the system considered. Horizontal permeabilities, Kh, vary up to 10 Darcies, and the Kv/Kh ratio is 0.1. The reservoir sands are turbidite sheets and the structure is a steeply dipping (38 degree) anticline trapped against a salt diaper. The sector that has been cut out of the whole reservoir model has a total length of 9.1 km and a cross section of 3.7 km, with an average sand thickness of 85 m. The figure also shows position of CO_2 injection well I1 up dip in the structure, and the closer position for the brine production well, P1. For the scenarios run with the distant producer, it is located the same distance again away from the injector, towards the right hand side of the model.

The porosity map is shown in Figure 7-2, again with evidence of heterogeneity.

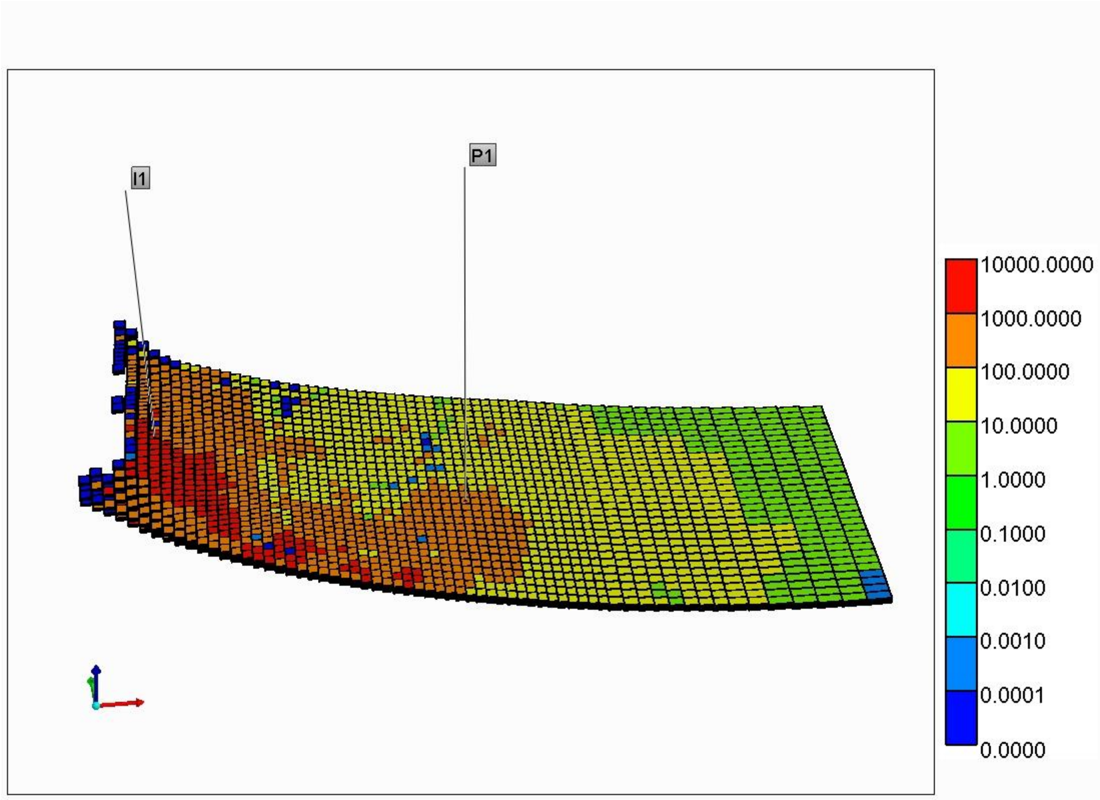


Figure 7-1. Permeability distribution (in mD) in synthetic dipping model, with horizontal permeabilities varying up to 10 Darcies. Figure also shows position of CO_2 injection well I1 up dip in the structure, and the closer position for the brine production well, P1.

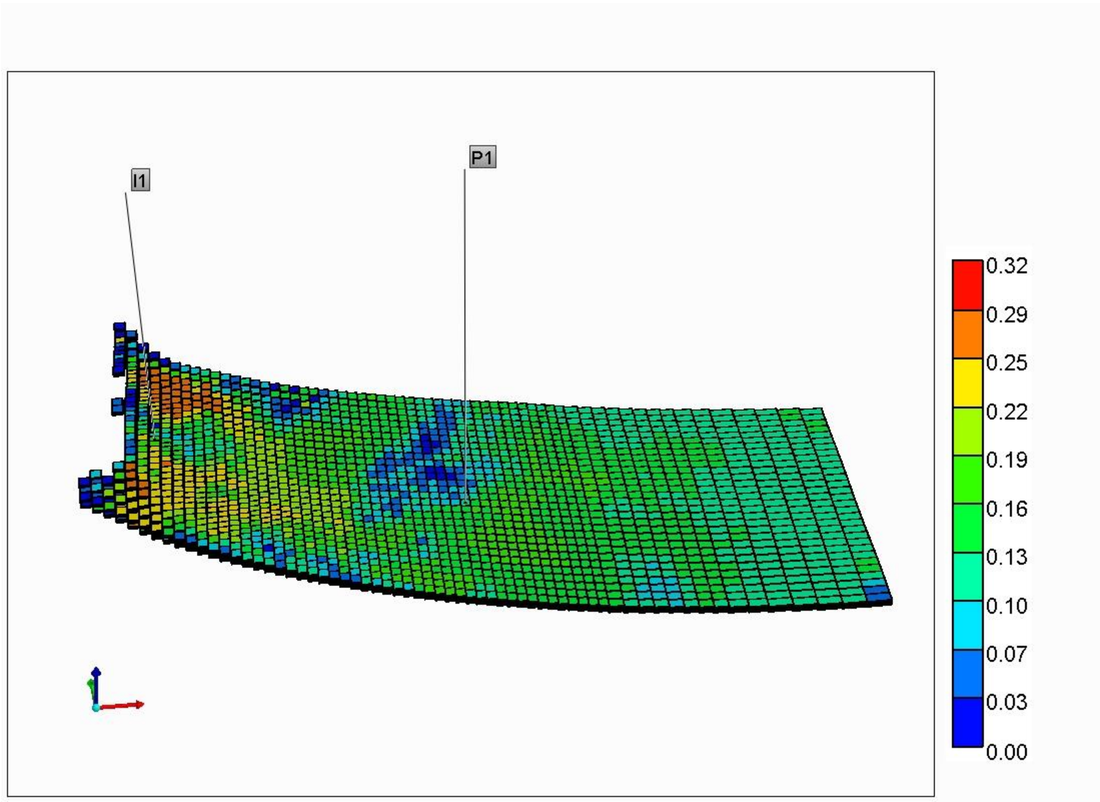


Figure 7-2. Porosity distribution (fraction) in synthetic dipping model.

In the first set of calculations, there was a target set to inject CO_2 at a rate of 0.435 Mt/yr for 20 years. Figure 7-3 shows that if a high pressure limit (ΔP = 63,000 kPa) is set and there is no brine production (red line), then this injection rate can be maintained until the well pressure reaches the limit after 13 years of injection. If a distant or a close brine producer is included, producing brine at a rate of up to 1590 m^3/day, then this pressure limit will not be reached during the 20 years.

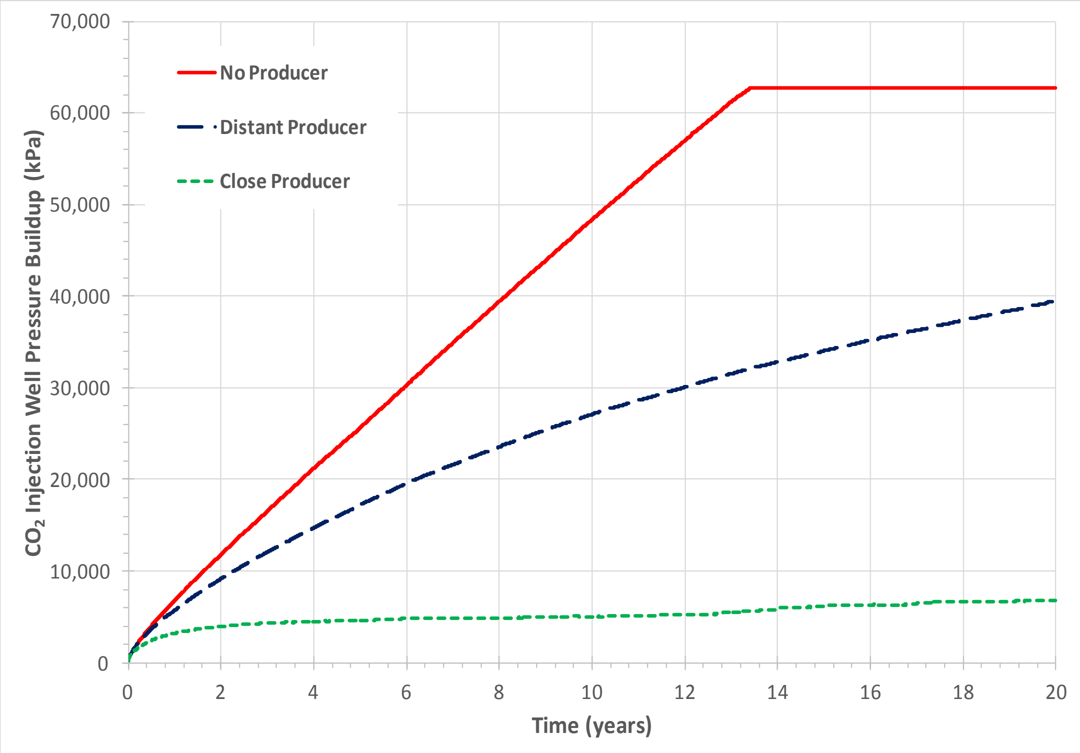


Figure 7-3. Pressure responses in well injecting at 0.435 Mt/yr for 20 years if a high pressure limit (ΔP = 63,000 kPa) is set.

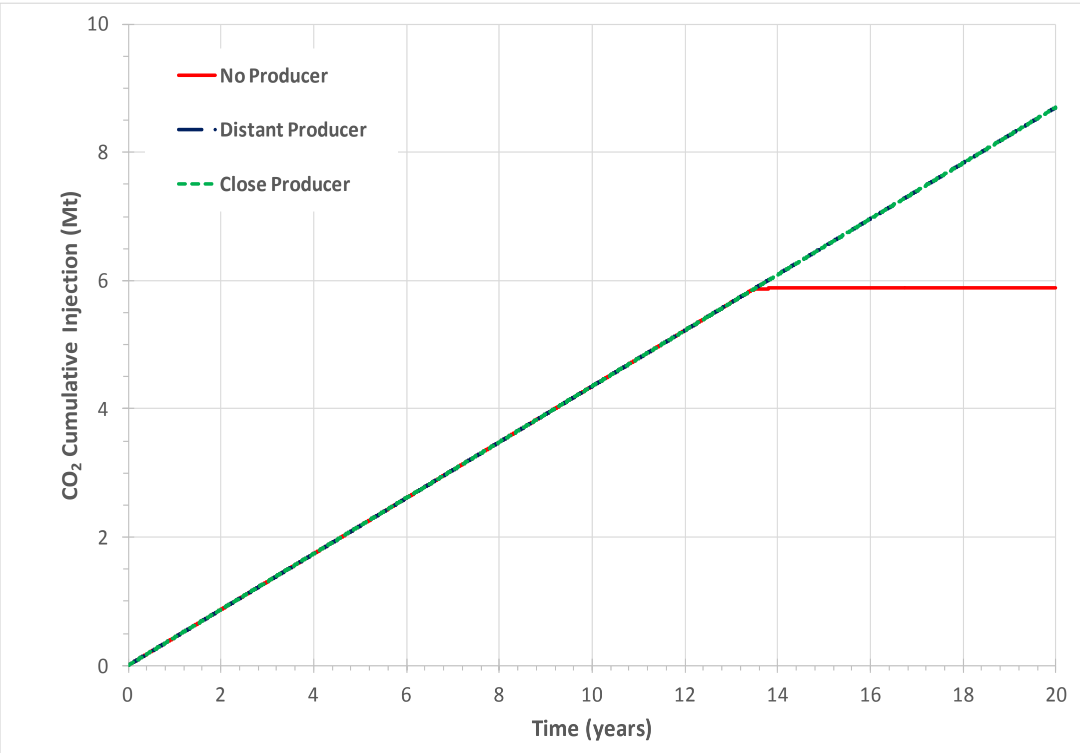


Figure 7-4. Cumulative CO_2 injection in well injecting at 0.435 Mt/yr for 20 years if a high pressure limit (ΔP = 63,000 kPa) is set.

Figure 7-4 identifies that because the pressure limit is reached after 13 years if there are no brine production wells, the maximum CO_2 storage capacity is just under 6 Mt. With pressure relief from production wells, wherever they are located downdip, it would be possible to store at least 8.5 Mt.

If the pressure limit is reduced to ΔP = 7,600 kPa, then this changes the outcome quite considerably. Figure 7-5 shows that the pressure limit is reached within 1 year if there is no brine production, and even if there is brine production at the more distant location, this will not stop the pressure limit being reached. However, if brine production takes place at the closer position, then the pressure limit is not reached.

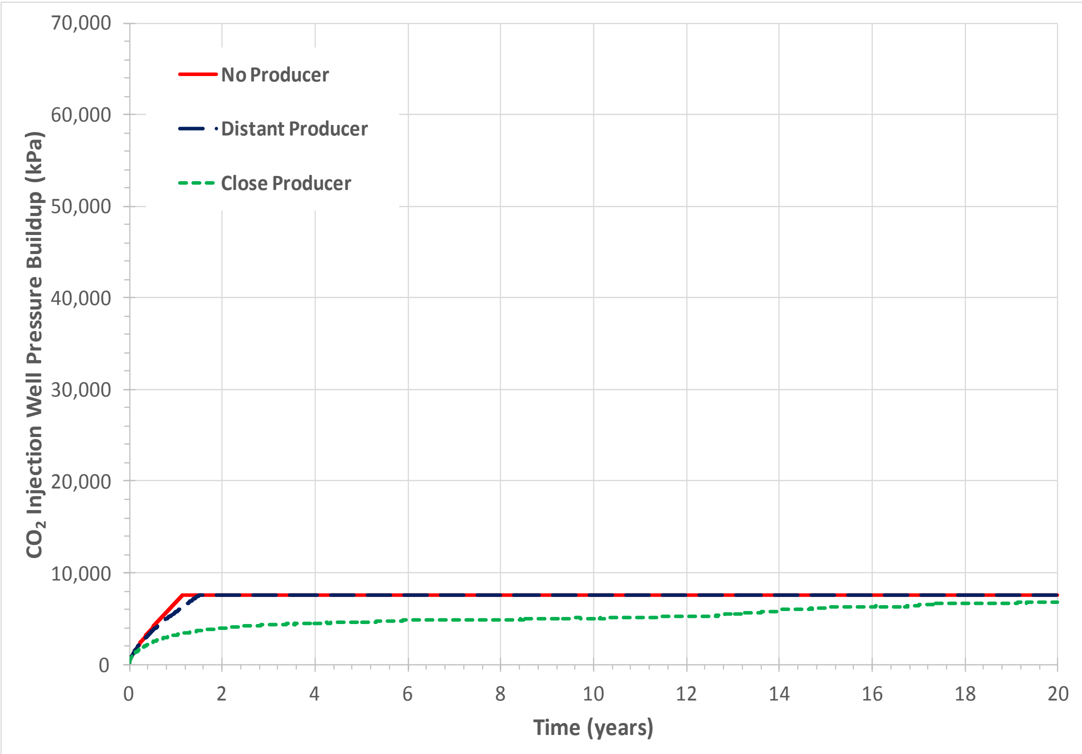


Figure 7-5. Pressure responses in well injecting at 0.435 Mt/yr for 20 years if a low pressure limit (ΔP = 7,600 kPa) is set.

The fact that with no brine production the pressure limit is reached within the first year means that the storage capacity in this scenario is limited to less than 1 Mt (see Figure 7-6). However, a distant brine production well, despite meaning that the injection well reaches its pressure limit, does allow the injector to remain open, albeit injecting at a lower rate to avoid exceeding the pressure limit. The result is that over 20 years a total of 4 Mt may be injected. However, with the closer production well, because the upper pressure limit is never reached, the injection well is able to maintain its originally set injection rate, and so a total of over 8 Mt can be injected.

These calculations mean that in the case of the higher pressure limit, inclusion of a brine production well could extend the life of the injection project from 14 to 20 years, regardless of where the well is positioned, but if the pressure limit is lower, then the impact is much greater, and with the closer production well it would be possible to increase the storage capacity from less than 1 Mt to over 8 Mt (or, more likely, change the storage project from not viable at only one year of injection to potentially viable at 20 years of injection).

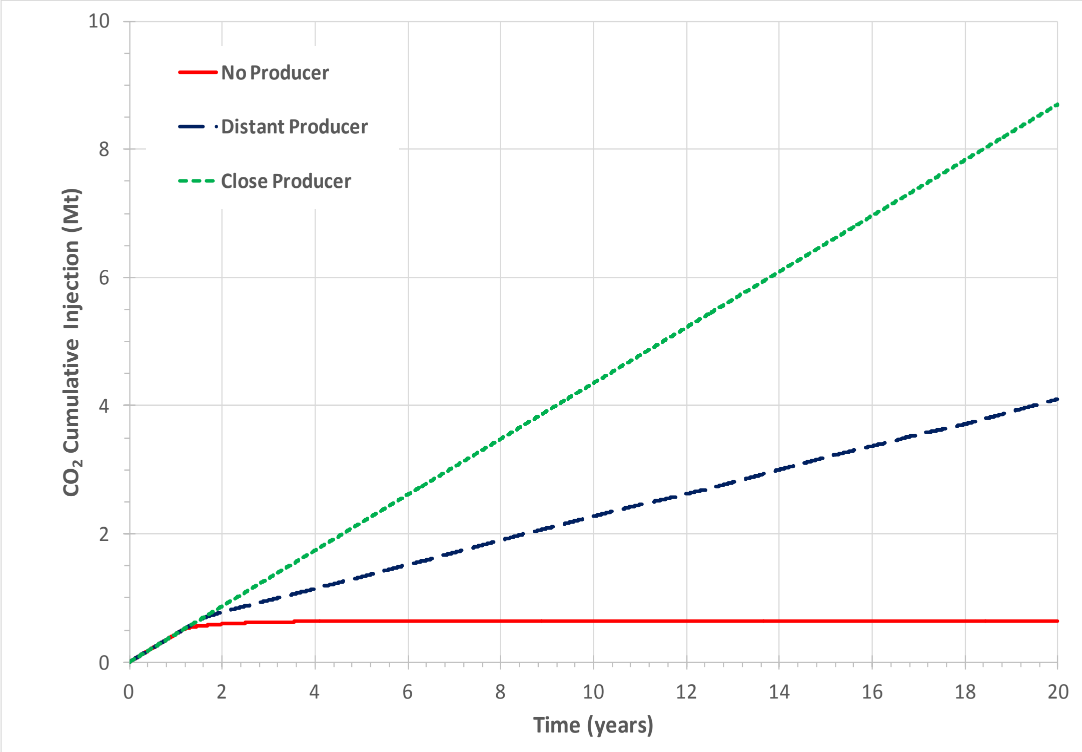


Figure 7-6. Cumulative CO_2 injection in well injecting at 0.435 Mt/yr for 20 years if a low pressure limit (ΔP = 7,600 kPa) is set.

If the injection rate is increased to 1.307 Mt/yr, similar behaviour as above is observed for the lower pressure limit scenario. However, for the higher pressure limit, Figure 7-7 shows the pressure response and Figure 7-8 the storage capacity.

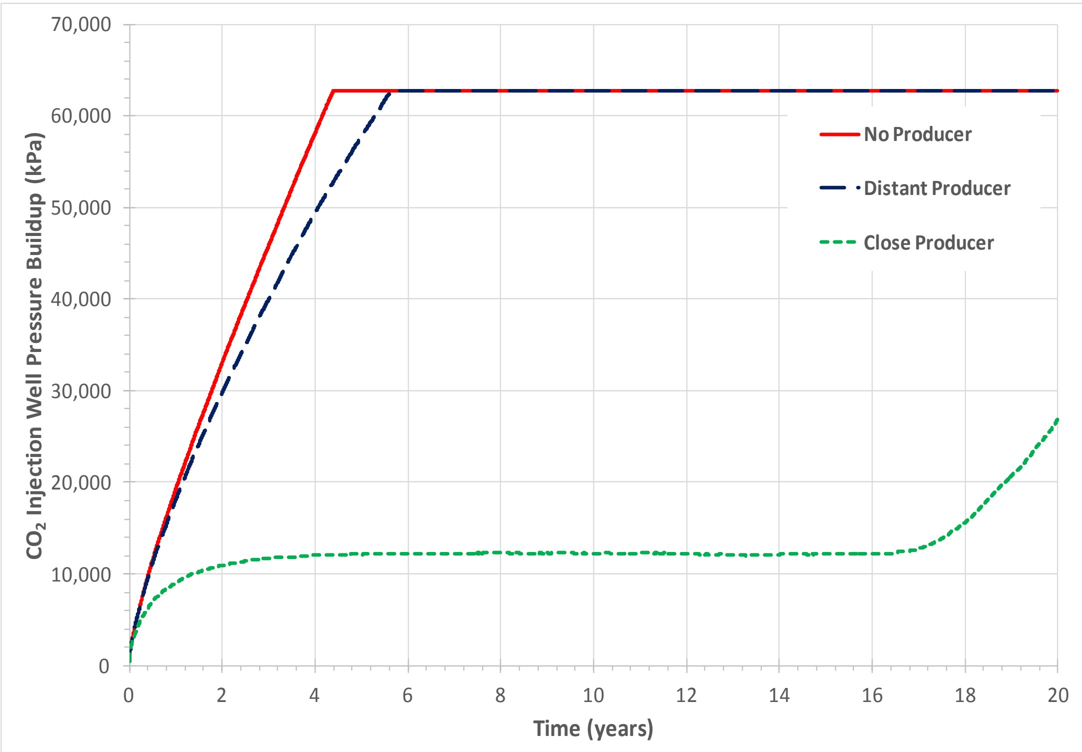


Figure 7-7. Pressure responses in well injecting at 1.307 Mt/yr for 20 years if a high pressure limit (ΔP = 63,000 kPa) is set.

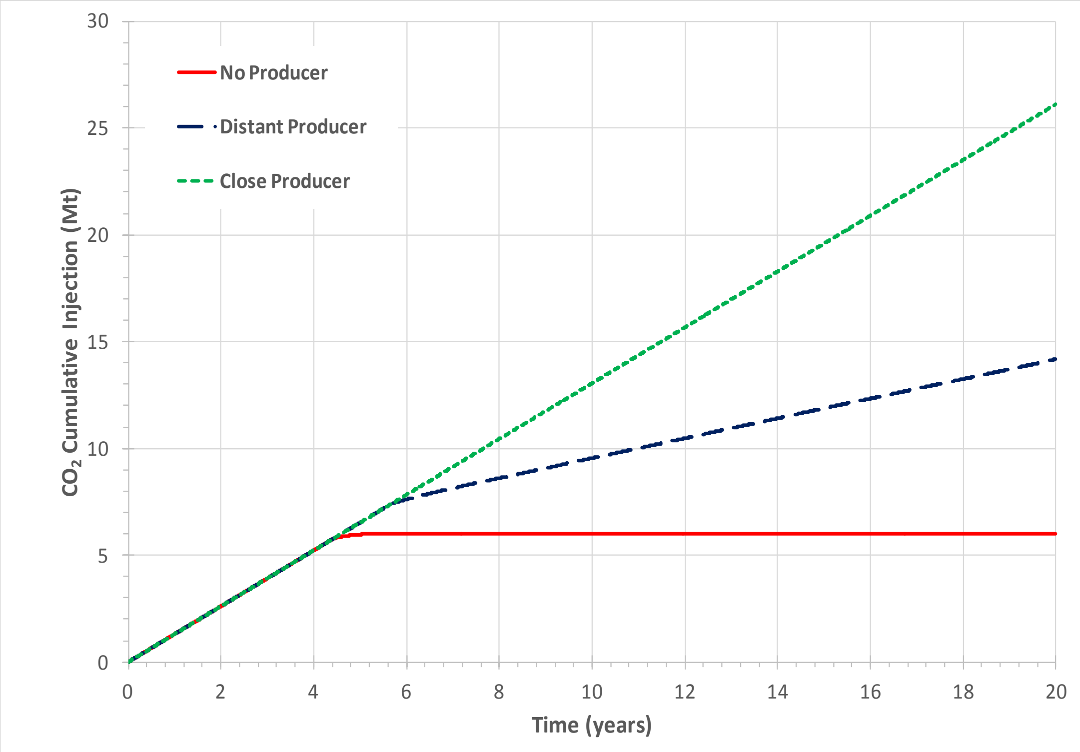


Figure 7-8. Cumulative CO_2 injection in well injecting at 1.307 Mt/yr for 20 years if a high pressure limit (ΔP = 63,000 kPa) is set.

With the high pressure limit and no brine production well, injection can be maintained at 1.307 Mt/yr for fewer than 5 years, resulting in a total of 6 Mt of CO_2 being stored. With a distant brine production well, this may be increased to 14 Mt. With a close production well, the site can store 26 Mt over 20 years. The results are summarised in Table 7-1.

Table 7-1. Storage capacity, duration of injection period and highest observed differential pressure for each scenario.

Case	Target CO_2 injection rate (Mt/yr)	Differential pressure limit (kPa)	Brine producer	Storage capacity (Mt)	Injection period (years)	Highest observed differential pressure (kPa)
1	0.435	7,600	No	0.64	5.4	7,600
2	0.435	7,600	Distant	4.10	20	7,600
3	0.435	7,600	Close	8.70	20	6,785
4	0.435	63,000	No	5.88	13.9	63,000
5	0.435	63,000	Distant	8.70	20	39,470
6	0.435	63,000	Close	8.70	20	6,785
7	1.307	7,600	No	0.55	0.9	7,600
8	1.307	7,600	Distant	4.26	20	7,600
9	1.307	7,600	Close	23.3	20	7,600
10	1.307	63,000	No	6.01	6.2	63,000
11	1.307	63,000	Distant	14.2	20	63,000
12	1.307	63,000	Close	26.1	20	26,905

In none of the simulations performed above did the injected CO_2 break through to the brine production well. Figure 7-9 shows the CO_2 distribution after 20 years injection for case 12, which is the case with the highest cumulative CO_2 injection. Figure 7-10 shows the co2 mole fraction in the water phase after 20 years. Neither free phase CO_2 nor aqueous phase CO_2 has broken through to the close producer at this time.

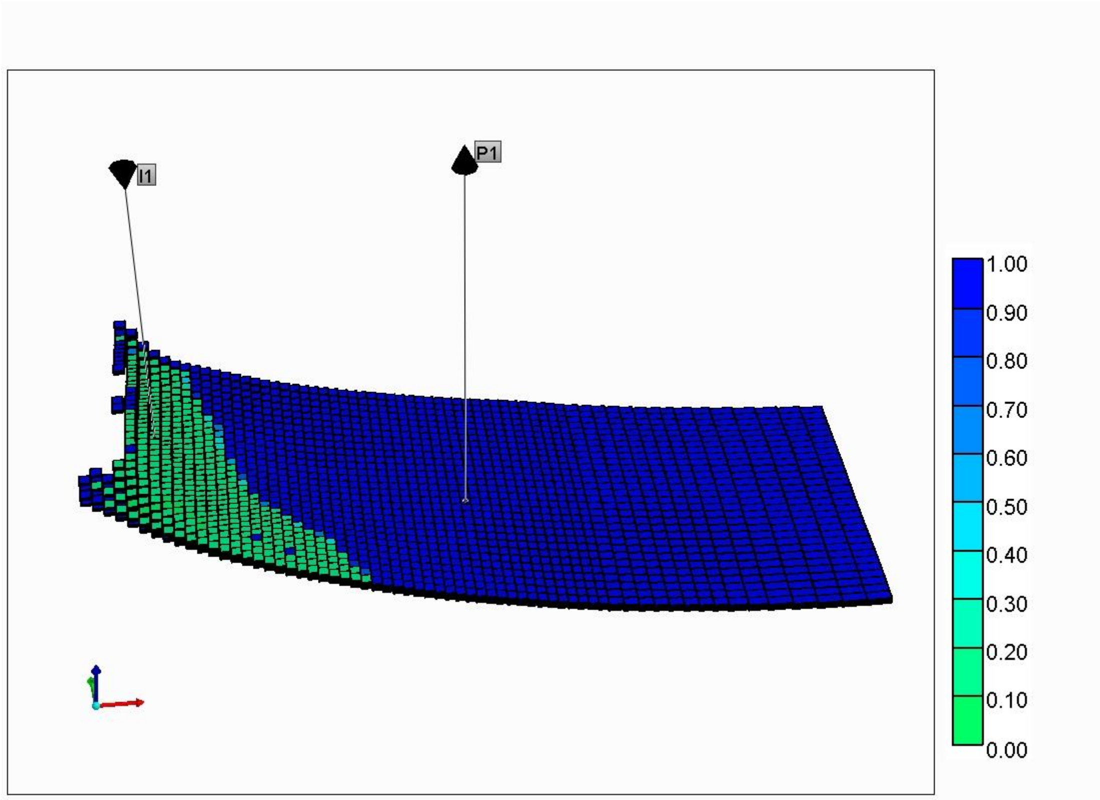


Figure 7-9. Water saturation (showing CO_2 distribution) for case where 1.307 Mt/yr is injected for 20 years.

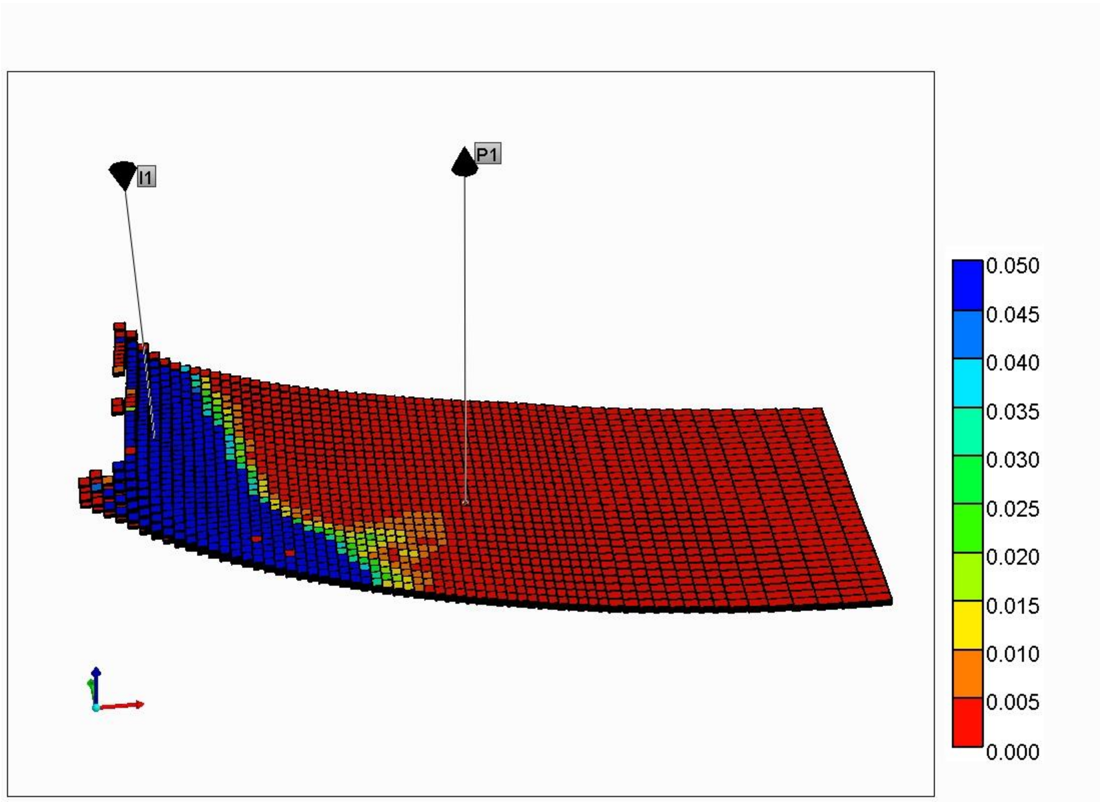


Figure 7-10. Mole fraction of CO_2 in the water phase for case where 1.307 Mt/yr is injected for 20 years.

7.4. Conclusions

A synthetic case with a steeply dipping structure demonstrates that very significant increases in capacity can be achieved in gravity stable scenarios, and that inter well distances are an important optimisation parameter. As an example, when injecting at a rate of 1.307 Mt/yr, even with a moderately high pressure increase limitation of 63,000 kPa, the correctly positioned brine production well can yield a more than fourfold increase in storage capacity over a 20 year period of injection.

8. Conclusions and Further Work

This project addresses the potential to significantly increase CO_2 storage capacity by producing brine through dedicated production wells. This is a technique currently included in development plans for CO2 storage sites. The production of water creates voidage to increase storage capacity and reduce the extent of pressure increase due to CO_2 injection. Five systems are considered: the Forties Aquifer, the Bunter Aquifer, the depleted Hamilton gas field, a producing North Sea oil field, and a synthetic tilted aquifer.

The **Forties system** is sufficiently large that for lower CO_2 injection rates (order 2-5 Mt/y), brine production does not yield any increase in storage capacity, and therefore should not be considered. For an intermediate injection rate (10 Mt/y) the capacity of the system is such that initially there is no benefit from brine production. However, as pressure builds up over time, brine production becomes an increasingly useful method of increasing storage capacity. Above 15 Mt/y CO_2 injection rates, brine production should be considered from the outset. At very high injection rates, say 40 Mt/y, breakthrough of CO_2 at the production wells is so quick that the benefit of brine production is short lived. A full set of calculations of CO_2 injection and brine production well numbers, brine production rates and maximum injection pressures have been entered into tables, along with data on spatial distribution of wells, and these have been passed on to Element Energy to provide input for their economic calculations. A second set of calculations for the same system, but assuming higher average reservoir permeabilities, has also been performed, and the same type of data will be supplied to Element Energy.

At lower CO_2 injection rates brine production yields no benefit in the **Bunter system** studied. The nature of the Bunter aquifer, with higher permeabilities and dome structures results in higher injection rates being possible with no benefit from brine production – up to 15 Mt/y. Also, the higher permeabilities mean that even at these higher injection rates, fewer brine production wells are required to provide the required pressure management. A set of calculations for this system has been performed, and again the same type of data will be supplied to Element Energy

The CO_2 storage capacity of the depleted **Hamilton gas field** can be enhanced by brine production and further enhanced by low injection rates, consistent with maintaining the store pressure above that required for super-criticality of the injected CO_2. The predicted capacity is constrained by the permitted CO_2 flow rates, either in the brine production wells or migration to parts of the formations outwith the original area of the hydrocarbon trap. Given this constraint, the potential for extension of life as a store is significant. This set of calculations is now complete.

In the case of the **North Sea oil field** studied, water injection can be partially replaced by CO_2 injection deep into the aquifer, and despite CO_2 breakthrough at the producers (and hence a need to recycle CO_2) a net amount of 54 Mt of CO_2 can be stored over a 20 year period, whilst increasing the oil recovery factor from 54% under pure water flooding in that same time period to over 59%, and reducing the requirement for water injection (with a modest reduction in water production also). The improvement in oil recovery may be attributed to microscopic (reduction in residual oil saturation in contacted zones) and macroscopic (better sweep efficiency) mechanisms. The prime interest in this study is, however, the potential to use CO_2 injection deep into the aquifer to at least partially replace water injection, here *reduced* water injection having a similar impact on storage potential to water production considered in the other cases studied. This set of calculations is now also complete.

A fifth **synthetic case with a steeply dipping structure** demonstrates that very significant increases in capacity can be achieved in gravity stable scenarios, and that inter well distances are an important optimisation parameter. The study identified that a single brine production well could increase the storage capacity by a factor greater than four, consistent with previous studies (Akhurst et al, 2011). This model will be used for further study as part of an MSc project at Heriot-Watt University, alongside use of a simple box model. Numerous sensitivity calculations will be performed, including impact of permeability and heterogeneity, well spacing, and pressure limits.

Calculations on two further aquifers, selected as part of the aquifer selection process, the **Firth of Forth system** and the **Tay Aquifer system**, are also underway at the time of writing this report. Data similar to those generated for the Forties and Bunter systems will be supplied to Element Energy. Further work will also consider various logistical aspects of brine production and disposal.

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