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Public abstract

This report is part of the research project MiReCOL (Mitigation and Remediation of CO_2 leakage) funded by the EU FP7 program[1]. Research activities aim at developing a handbook of corrective measures that can be considered in the event of undesired migration of CO_2 in the deep subsurface reservoirs. MiReCOL results support CO_2 storage project operators in assessing the value of specific corrective measures if the CO_2 in the storage reservoir does not behave as expected. MiReCOL focuses on corrective measures that can be taken while the CO_2 is in the deep subsurface. The general scenarios considered in MiReCOL are 1) loss of conformance in the reservoir (undesired migration of CO_2 within the reservoir), 2) natural barrier breach (CO_2 migration through faults or fractures), and 3) well barrier breach (CO_2 migration along the well bore).

This element of the MiReCOL project aims to investigate the possibilities of flow diversion and mobility control of an undesired migration of CO_2 plume within the storage reservoir.
The first part of this deliverable provides the results of numerical simulations for flow diversion of the CO_2 plume by the use of polymer-gel barriers. It was assumed that CO_2 leakage through a

[1] More information on the MiReCOL project can be found at www.mirecol-co2.eu.

sub-seismic fault was detected in the shallow aquifer during injection. The results obtained from laboratory investigations of polymer-gel characterisation and core flooding experiments of the project were used to define a range of permeabilities for the polymer-gel barriers modelled.

Two scenarios were defined based on different layouts of polymer-gel barriers within the reservoir. Sensitivity analyses were carried out to assess the effectiveness of the barrier in diverting the flow of CO_2 plume from the leaky fault.

The second part of the deliverable describes a model for the creation of foam from injected surfactant and water that was developed within the Eclipse simulator and used to test the effects of various injection parameters on leakage in a generic reservoir model. The most effective parameters in reducing CO_2 migration were found to be the duration of surfactant solution injection and the location of the injection well, to prevent early by-passing of the foam plug. Generally the most effective leakage mitigation was achieved by injecting over a long time, i.e. using the highest amounts of surfactant.

The results of this work will support further work with regards to polymer-gel barrier remediation implementation and eventually the comparison of various remediation methods in a later part of the MiReCOL project.

Public introduction

In comparison with other likely storage sites, such as the depleted hydrocarbon fields, knowledge of the geological and petrophysical properties of saline aquifers is extremely limited. Hence, a considerable degree of uncertainty in the conformance of CO_2 flow in the subsurface in comparison with that estimated by theoretical/numerical computations is expected. This uncertainty may lead to undesired and unpredicted preferential flow of CO_2 into parts of the host reservoir, or leakage into shallower formations. Mechanisms that could lead to migration or leakage of CO_2 into shallower formations and ultimately leakage to the atmosphere could include: unwarranted intrusion, equipment failure *e.g.* abandoned wells, faults reactivation due to over-pressurisation, or geochemical reactions between the CO_2 and the cap rock, and sub-seismic faults undetected during the site characterisation phase prior to CO_2 injection (IEAGHG Report, 2007).

In order to mitigate undesired CO_2 plume migration and its leakage into shallower formations, flow diversion measures may be implemented, such as: i) localised injection of brine creating a competitive fluid movement, ii) change of injection strategy, or iii) localised reduction in permeability by the injection of gels or foams, or by immobilising the CO_2 in the pore space.

Crosslinked hydrolysed polymer-gel injection is used in petroleum industry to improve conformity of fluid flow in the reservoir, remediate leakage around wells, and also used in conjunction with enhanced oil recovery at various temperature and pressure conditions (Sydansk, 1998; Hild and Wackowski, 1999; Sydansk and Southwell, 2000; Sydansk, et al., 2004; Turner and Zahner, 2009; Al-Muntasheri et al., 2010; Saez et al., 2012). Water-based gels are highly elastic semi-solids with high water content, trapped in the three-dimensional polymer structure of the gel (Vossoughi, 2000). Polyacrylamide (PAM) is the main crosslinked polymer used mostly by the industry (Flew and Sellin, 1993; Rodriguez et al., 1993). The use of biopolymers is more challenging as compared to the synthetic polymers due to chemical degradation at higher temperatures, causing the loss of mechanical strength (Sheng, 2011). Most of polymer-gel systems are based on crosslinking of polymers with a heavy metal ion. The most common heavy metal ion used is chromium III. However, in view of its toxicity and related environmental concerns (Stavland and Jonsbraten, 1996; Vossoughi, 2000), its application in reservoir conformance and CO_2 leakage remediation is considered to be limited. Therefore, more environmental friendly crosslinkers such as boron (Sun and Qu, 2011; Legemah et al., 2014), aluminium (Smith, 1995; Stavland and Jonsbraten, 1996) and zirconium (Lei and Clark, 2004) have been proposed and used in recent years.

Several commercial and research-purpose simulators have been used to simulate chemical/polymer injection into deep geological formations, most of which was developed for the purpose of Enhanced Oil Recovery (EOR) from hydrocarbon reservoirs. For instance, a two phase, four component polymer EOR model was developed by Wegner and Ganzer (2012) using COMSOL to simulate the displacement of oil by aqueous polymer solutions. Gharbi *et al*. (2012) performed history-matching to assess the potential of surfactant/polymer flooding in a Middle Eastern reservoir, using the chemical flood reservoir simulator (UTCHEM) developed at the University of Texas at Austin. In addition, Schlumberger's simulator, ECLIPSE, has also been used for polymer flooding and EOR in the Norne Field E-Segment, *e.g.* by Sarkar (2012) and Amirbayov (2014).

A foam system consists of a continuous water phase with dispersed gas bubbles at a given volumetric fraction. Gas bubble formation requires a certain amount of energy which is provided by shear, and is stabilized by surfactant foaming agents dissolved in the water phase, or the gas phase in the case of CO_2. For the use of foams as gas blocking agents, the placement of the foam, its resistance to gas flow and its durability are of the outmost importance for the efficiency and economics of the process. Though the use of "classical" foams has been considered as a promising technology for controlling excessive gas movement, it was shown that these foams have limited lifetime (weeks to months) and the treatment needs to be repeated often (Albrecht and Marsden et al., 1970; Wong et al., 1997; Wassmuth et al., 2001; Cubillos et al., 2012).

Compared with other foam systems such as N_2-foams or natural gas-foams, CO_2-foams usually generate much lower Mobility Reduction Factors due to the impact of CO_2 on the interfacial tension. For CO_2, the mobility reduction factor is usually much lower than with hydrocarbon gas and the maximum attainable effect decreases rapidly with CO_2 density (Chabert et al., 2012; Solbakken et al., 2013). With supercritical CO_2 it was inferred from a laboratory study using a classical foaming agent that probably only coarse foam-emulsions could be formed. However, recent results have shown that with dedicated surfactant formulations, high gas mobility reduction factors could be obtained even with dense- phase CO_2, indicating the formation of strong foams (Chabert et al., 2014).

Currently, large uncertainties remain regarding the actual physics underlying foam flow in porous media. Although previous studies have not proposed a satisfactory physical model for foam flow and propagation, they have generated a general though useful, phenomenological description of the rheological behaviour of foams in porous media (Gauglitz et al., 2002; Skauge et al., 2002; Tanzil et al., 2002; Farajzadeh et al., 2009; Enick et al., 2012; Chabert et al., 2013).

As part of the MiReCOL project, this report presents the results of numerical modelling work carried out to investigate the application of polymer-gels and foams for flow diversion of the CO_2 plume within the storage reservoir. The objective of the polymer-gel barrier simulations was: i) to perform reservoir simulations for different remediation layouts after CO_2 leakage has been detected, ii) to perform sensitivity analyses in order to assess the effectiveness of the polymer-gel barriers in diverting the flow of CO_2 plume. The results of laboratory investigations on polymer-gel characterisation and core flooding experiments carried out in the project were used to define a range of permeabilities of the polymer-gel barriers.

The second part of the report describes a model for the creation of foam from injected surfactant and water that was developed within the Eclipse simulator, which was used to test the effects of various injection parameters on leakage in a generic reservoir model. The most effective parameters in reducing CO_2 migration were found to be the duration of surfactant solution injection and the location of the injection well, to prevent early by-passing of the foam plug. Generally the most effective leakage mitigation was achieved by injecting over a long time, i.e. using the highest amounts of surfactant.

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1 INTRODUCTION

A number of risks of varying degree are associated with underground storage of CO_2. Contingency planning and analysis of possible future remediation actions are a requirement for realizing a permit for geological CO_2 storage.

In comparison with other likely storage sites, such as the depleted hydrocarbon fields, knowledge of the geological and petrophysical properties of saline aquifers is usually rather limited. Hence, a considerable degree of uncertainty in the conformance of CO_2 flow in the subsurface in comparison to that estimated by theoretical/numerical computations is expected. This uncertainty may lead to undesired and unpredicted preferential flow of CO_2 into parts of the host reservoir, or leakage into shallower formations.

Mechanisms that could lead to migration or leakage of CO_2 into shallower formations and ultimately leakage to the atmosphere could include: unwarranted intrusion, equipment failure *e.g.* abandoned wells, faults reactivation due to over-pressurisation, or geochemical reactions between the CO_2 and the cap rock, and sub-seismic faults undetected during the site characterisation phase prior to CO_2 injection (IEAGHG Report, 2007).

In order to mitigate undesired migration of the CO_2 plume and its leakage into shallower formations, flow diversion measures may be implemented, such as: i) localised injection of brine creating a competitive fluid movement, ii) change of injection strategy, or iii) localised reduction in permeability by the injection of various types of sealant.

The aim of the work reported here was to test the effectiveness of foam and gel injection as two distinct means of mitigating unwanted CO_2 migration within a storage reservoir. This was be done by means of characterizing typical examples of both foam and gel, then performing simulations in a numerical simulator of CO_2 migration and the flow diversion effect of the injected media.

The results will be used later in the MiReCOL project to compare the effectiveness of various methods to counteract unwanted migration of CO_2.

2 POLYMER GEL REMEDIATION AS FLOW DIVERSION OPTION

In comparison to other likely storage sites, such as the depleted hydrocarbon fields, knowledge on the geological and petrophysical properties of saline aquifers is usually more limited. Hence, a considerable degree of uncertainty in the conformance of CO_2 flow in the subsurface in comparison to that estimated by theoretical/numerical computations is expected. This uncertainty may lead to undesired and unpredicted preferential flow of CO_2 into parts of the host reservoir, or leakage into shallower formations. Mechanisms that could lead to migration or leakage of CO_2 into shallower formation and ultimately leakage to the atmosphere could include: unwarranted intrusion, equipment failure *e.g.* abandoned wells, faults reactivation due to over-pressurisation, or geochemical reactions between the CO_2 and the cap rock, and sub-seismic faults undetected during the site characterisation phase prior to CO_2 injection (IEAGHG Report, 2007).

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As part of the MiReCOL project, this report presents the results of the numerical modelling carried out to investigate the application of polymer-gel barriers for flow diversion of a CO_2 plume within the storage reservoir. The objective of this work was: i) to perform reservoir simulations for different remediation layouts after CO_2 leakage has been detected, ii) to perform sensitivity analyses in order to assess the effectiveness of the polymer-gel barriers in diverting the flow of CO_2 plume. The results of laboratory investigations on polymer-gel characterisation and core flooding experiments, provided in Deliverable 6.2 of the project, were used to define a range of permeabilities of the polymer-gel barriers.

2.1 Reservoir model description

2.1.1 Structural and geological model

A numerical reservoir model was set up to study the mobility control of CO_2 plume using polymer-gel injection within a heterogeneous saline aquifer. The structural model used in this study represents a saline aquifer with a broad and considerably dipping anticlinal structure (Figure 1), where the containment of CO_2 is envisaged. The model grid spans an area of 36km×10km and includes five major sealing faults. The grid broadly comprises of three layers, namely: (1) a reservoir layer with an average thickness of 240m and resolution of 200m×200m×4m; (2) a caprock (seal) layer with an average thickness of 225m and resolution of 200m×200m×225m; and (3) a shallow aquifer layer with an average thickness of 175m and resolution of 200m×200m×175m. The depth of the model ranges between 1,087m and 3,471m.

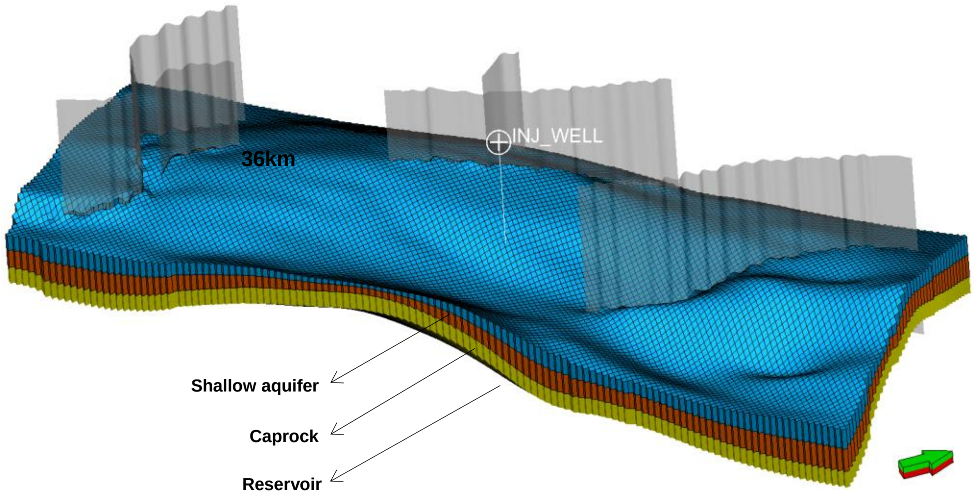


Figure 1. *The structural model of the numerical saline aquifer (36km×10km) containing five major faults and three stratigraphic layers: reservoir layer, caprock (seal) layer and shallow aquifer layer.*

The geological model of the reservoir layer is represented by a fluvial-channel system, typically containing braided sandstone channels and interbedded floodplain deposits (the inter-channel region) of mudstone or siltstone. These generally represent the fluviodeltaic progradation and floodplain deposition formations found in the Triassic of the Barents Sea. The channel layout parameters implemented in the model to represent the fluvial-channel system are given in *Table 1*. The range of the petrophysical properties used in the static geological model attribution (*Table 2*) are based on the Late Triassic Fruholmen Formation in the Hammerfest Basin (NPD, 2013), which is located at depths similar to those considered in this model. The petrophysical attributions of the geological model were generated using Sequential Gaussian Simulation (SGS) in order to represent the variability in the distribution of these values. Example realisations of the porosity and horizontal permeability distributions for the top reservoir layer are illustrated in Figure 2.

Table 1. *Channel layout parameters used in the reservoir layer of the geological model.*

	Min	Mean	Max
Amplitude [m]	400	500	600
Wavelength [m]	14,000	15,000	16,000
Width [m]	1,400	1,500	1,600
Thickness [m]	4	8	12

Table 2. *Petrophysical properties used in the geological model.*

Petrophysical properties		Channels	Inter-channel region	Caprock	Shallow aquifer
Porosity	Min, Mean, Max	0.1, 0.18, 0.25	0, 0.1, 0.25	0.01	0.05, 0.15, 0.25
	Standard deviation	0.05	0.05	0	0.05
Horizontal Permeability [mD] *	Min, Mean, Max	125, 3000, 7000	0.1, 10, 100	0.0001	100, 3000, 5000
	Standard deviation	2000	40	0	1000
NTG	Min, Mean, Max	0.6, 0.9, 1	0, 0.2, 0.5	0.01	0.6, 0.9, 1
	Standard deviation	0.05	0.05	0	0.05

*vertical permeability = 0.1 × horizontal permeability

(a)

(b)

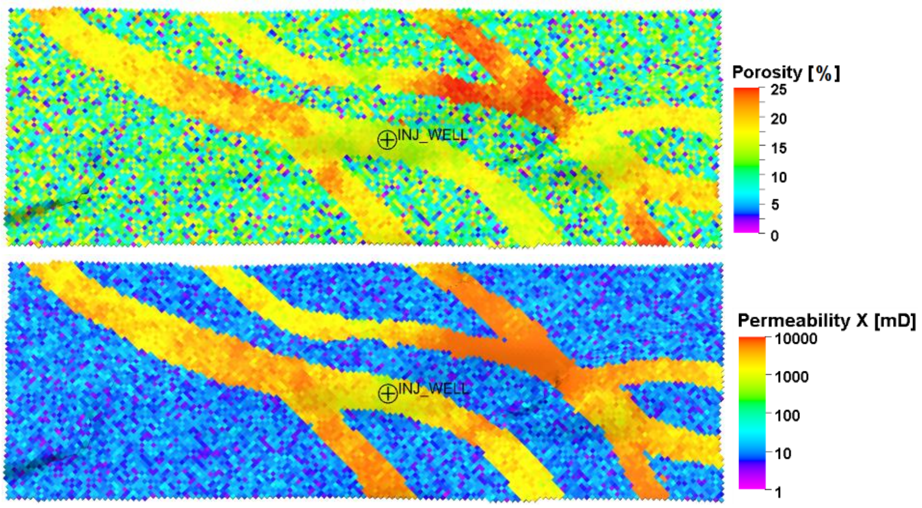


Figure 2. *Example realisations of petrophysical properties distribution for the top layer of the reservoir: (a) Porosity; (b) Horizontal permeability covering the area of the reservoir model (36km×10km).*

2.1.2 Dynamic properties of the reservoir model

Similar to the petrophysical properties of the geological model attribution, the dynamic properties of the reservoir model have been selected based on the values reported for the reservoir conditions found in the corresponding or neighbouring Barents Sea formations. The salinity of the formation water was chosen to be 14% based on the values reported for the Tubåen formation of the Snøhvit field (Benson, 2006), which is also part of the Realgrunnen Subgroup overlying the Fruholmen. The reservoir temperature was set at 93°C and the initial pressure of the reservoir model was assumed to be at hydrostatic pressure.

2.2 Dynamic modelling of CO_2 flow diversion

The dynamic model was set up in Schlumberger's Eclipse 300 (E300) software using the static geological model and the dynamic reservoir parameters described in the previous sections. The compositional flow simulation of CO_2 storage in the saline aquifer model was carried out by implementing a quasi-isothermal, multi-phase, and multi-component algorithm, enabled by the CO2STORE option, wherein mutual solubilities of CO_2 and brine are considered. Simulations were carried out for 30 years, comprising of the CO_2 injection, leakage detection, remediation, and post-remediation CO_2 injection periods.

For the purpose of this study, it was assumed that a sub-seismic fault is present in the formation as a pre-defined undesired migration pathway. This is represented by a local grid refinement additionally introduced in the structural model by means of the CARFIN option in Eclipse. Two scenarios were considered based on different layouts of the polymer-gel barriers for leakage remediation and flow diversion within the reservoir formation.

2.2.1 Scenario 1: Vertical polymer-gel remediation barrier layout

In order to setup the first scenario, a sub-seismic vertical fault was introduced in the model at a distance of 1km away from the injection well (INJ_WELL), located at the flank of the anticline (Figure 3). The fault has a lateral dimension of 800m×2m and is assumed to be non-sealing, with a uniform vertical permeability of 10,000mD and spanning the reservoir and the caprock thickness (approximately 450m) without appreciable formation displacement between the two sides of the fault.

The simulation of CO_2 injection in the saline aquifer was carried out at a rate of 1Mt/year, for a total period of thirty years comprising three stages: initial CO_2 injection until leakage detection, polymer-gel injection (remediation) in the reservoir, and post-remediation CO_2 injection. The leakage detection threshold assumed was 5,000 tonnes of free CO_2 in the shallow aquifer (Benson, 2006).

Once the leakage through the sub-seismic fault was detected, CO_2 injection was stopped for a period of six months, at the end of which permeability reduction in the reservoir due to polymer-gel injection is implemented. The polymer-gel barrier was assumed to span the reservoir thickness and have an effective region of influence much longer than the subseismic fault. The dimensions of the effective remediation barrier implemented were 1,600m×20m×240m, at a distance of approximately 100m away from the fault towards the injection well, as illustrated in Figure 3.

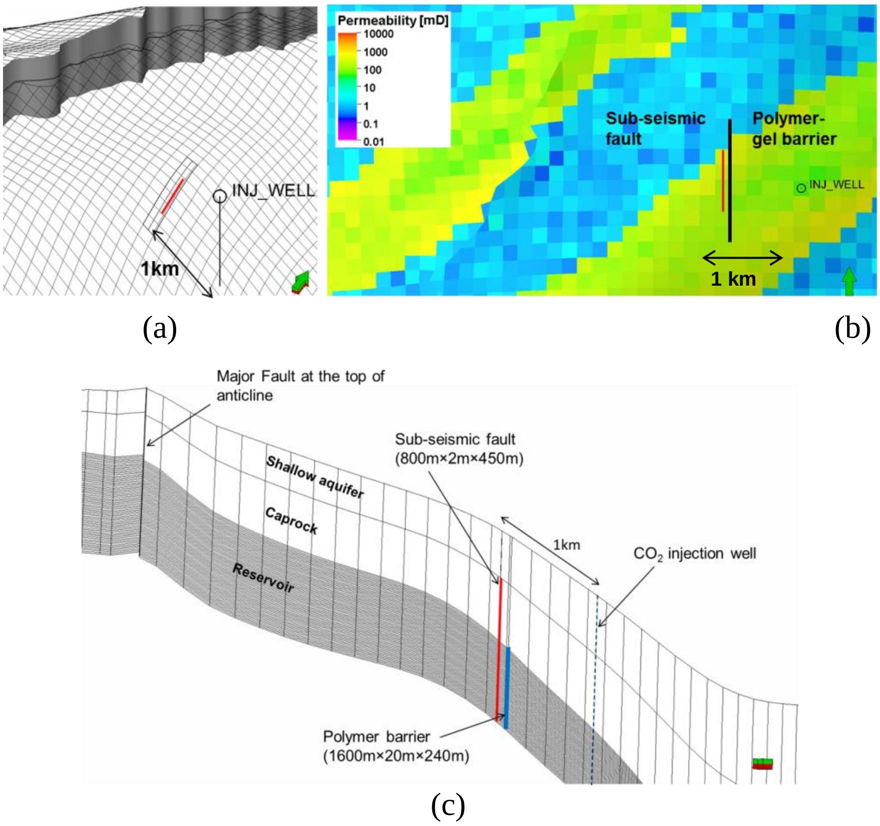


Figure 3. *(a) The grid refinement representing the sub-seismic fault feature (800m×2m) and polymer-gel barrier (1600m×20m), located 1km away from the injection well; (b) permeability attribution and position of the polymer-gel barrier between the injection well and the sub-seismic fault at the top of the storage reservoir; (c) cross-sectional view showing the local grid refinement representing the sub-seismic fault feature in red, and the vertical polymer-gel barrier in blue.*

2.2.1.1 CO_2 plume migration results

With the remediation barrier in place, CO_2 injection was then re-started for the remaining simulation period, representing the post-remediation period.

The CO_2 injection was assumed to start in January 2015. Figure 4 illustrates the simulation results indicating the free CO_2 plume distribution after: (a) 1 year of simulation (January 2016); (b) 1.3 years of simulation when leakage was detected and CO_2 injection was stopped (April 2016); (c) 1.6 years of simulation when remediation was completed (October 2016); (d) 10 years of simulation (January 2025); (e) 20 years of simulation (January 2035); and (f) 30 years of simulation (January 2045). The results illustrate that polymer-gel barrier remediation induces flow diversion and consequently reduces the cumulative amount of CO_2 leakage into the shallow aquifer from 6 Mt, if no remediation is implemented, to approximately 0.2 Mt by the end of thirty years (shown Figure 6).

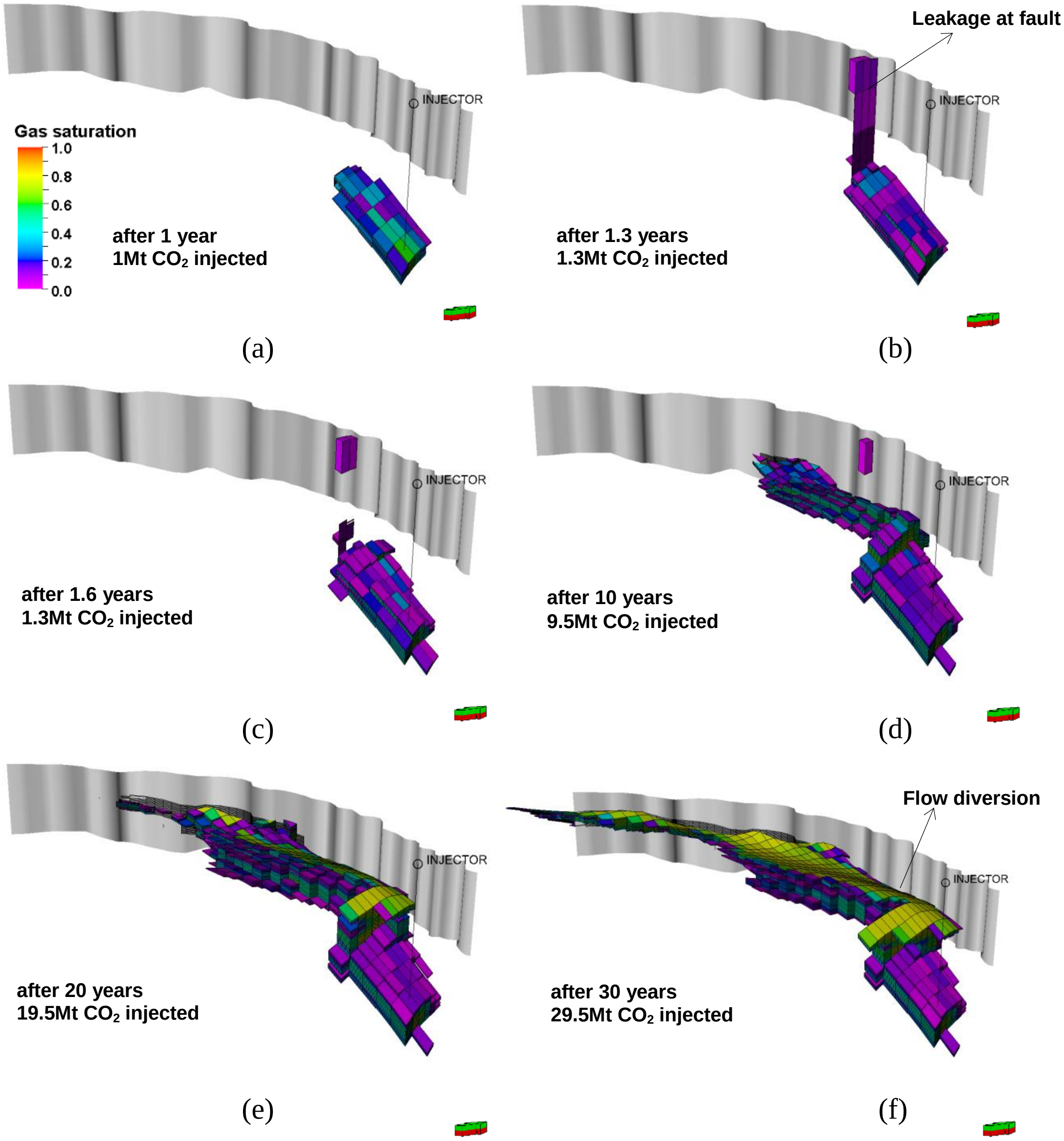


Figure 4. *Distribution of free CO_2 after: (a) 1 year of simulation (January 2016); (b) 1.3 years of simulation when leakage was detected and CO_2 injection was stopped (April 2016); (c) 1.6 years of simulation when remediation was completed (October 2016); (d) 10 years of simulation (January 2025); (e) 20 years of simulation (January 2035); and (f) after 30 years of simulation (January 2045).*

2.2.1.2 Sensitivity analysis for the effect of polymer-gel barrier permeability on flow diversion

Different permeability values at the location of the polymer-gel barrier were tested in the model, ranging from 0.01-10mD. This considers 2-5 orders of magnitude of permeability reduction for the channel region (with an average horizontal permeability of 3000mD), and 0-3 orders of magnitude of permeability reduction for the inter-channel region (with an average horizontal permeability of 10mD). The free CO_2 plume distributions at the end of the thirty years injection period, as illustrated in Figure 5, suggest that leakage through the fault continues during the post-remediation period when the barrier permeability is >0.1mD. For permeabilities below this value, the plume is more effectively diverted away from the fault.

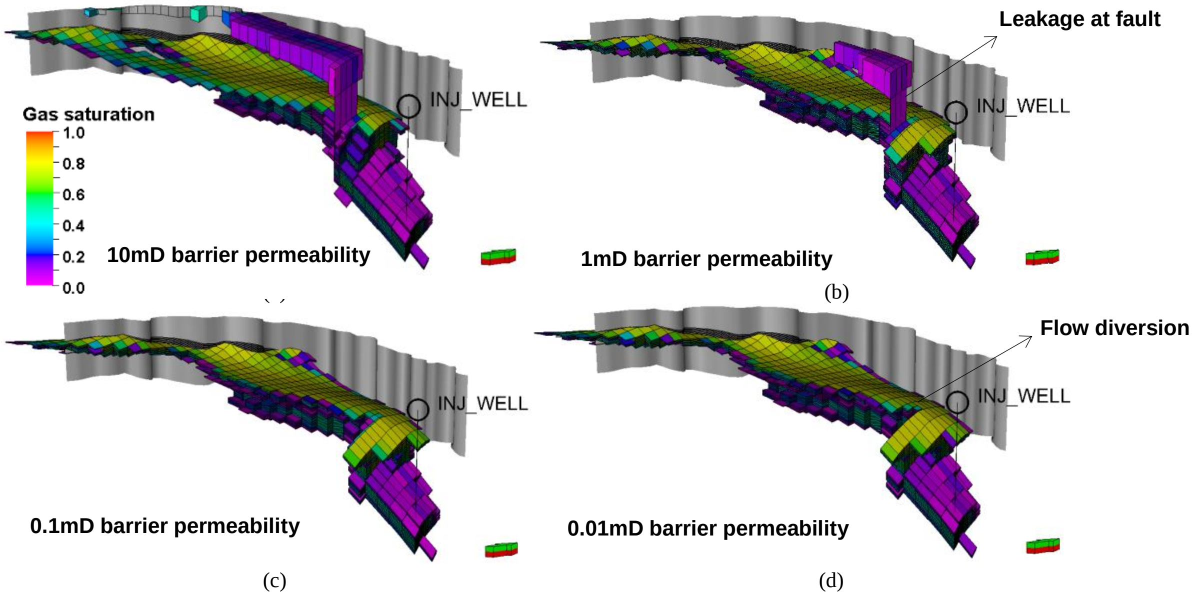


Figure 5. *Plume distribution at the end of the 30 year simulation period when the permeability of the polymer–gel barrier is: (a) 10mD; (b) 1mD; (c) 0.1 mD; (d) 0.01mD.*

Figure 6 illustrates the mass of cumulative CO_2 leakage in the shallow aquifer for the first ten years of the simulation period. The model estimates that, for example, leakage reduction achieved after five years of simulation lies in the range of 84% to 96% (*i.e.* reduced by ~1.6Mt to ~1.9Mt) for this scenario. Hence, leakage through the fault continues at a lesser rate during the post-remediation period for all the barrier permeabilities considered. In this the cumulative total mass of CO_2 leakage indicated in Figure 6, the free CO_2 accounts only for one fraction of the total CO_2 leakage. In fact, the detection limit of 5,000tonnes of free CO_2 corresponds to 86.3kt of the cumulative mass of total CO_2.

Figure 7 illustrates fraction of the injected CO_2 leaked into the shallow aquifer during post-remediation period. The results show that for case of un-remediated CO_2 injection, up to 49% of the injected CO_2 can be expected to leak; whereas for the remediated cases, the amount of CO_2 leakage is reduced to 0.7-15% of the injected CO_2, depending on the range of barrier permeabilities considered.

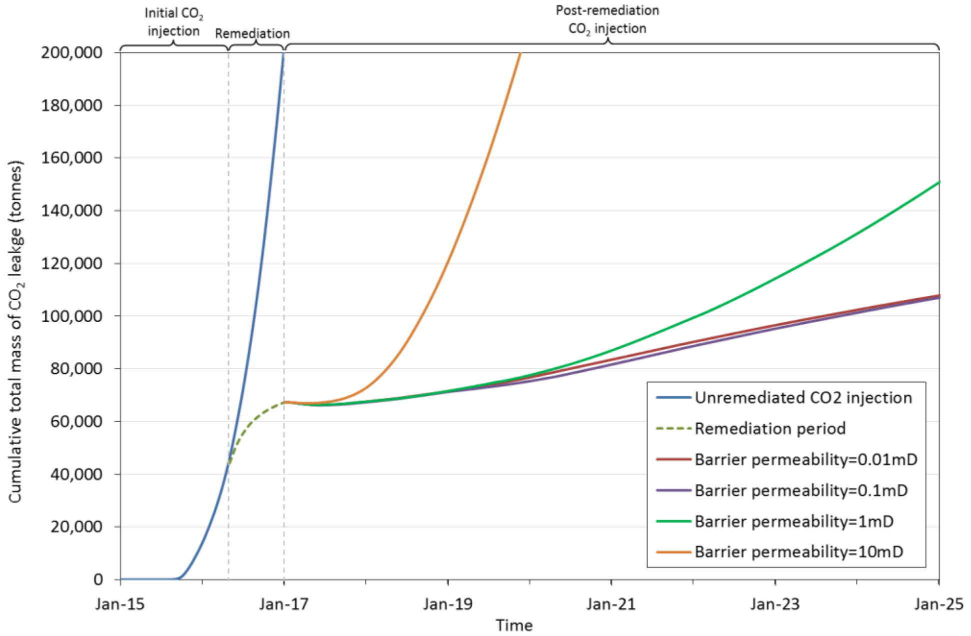


Figure 6. *Cumulative mass of total CO_2 (which includes free, dissolved and trapped components) that could leak in to the shallow aquifer for different cases of polymer-gel barrier permeabilities.*

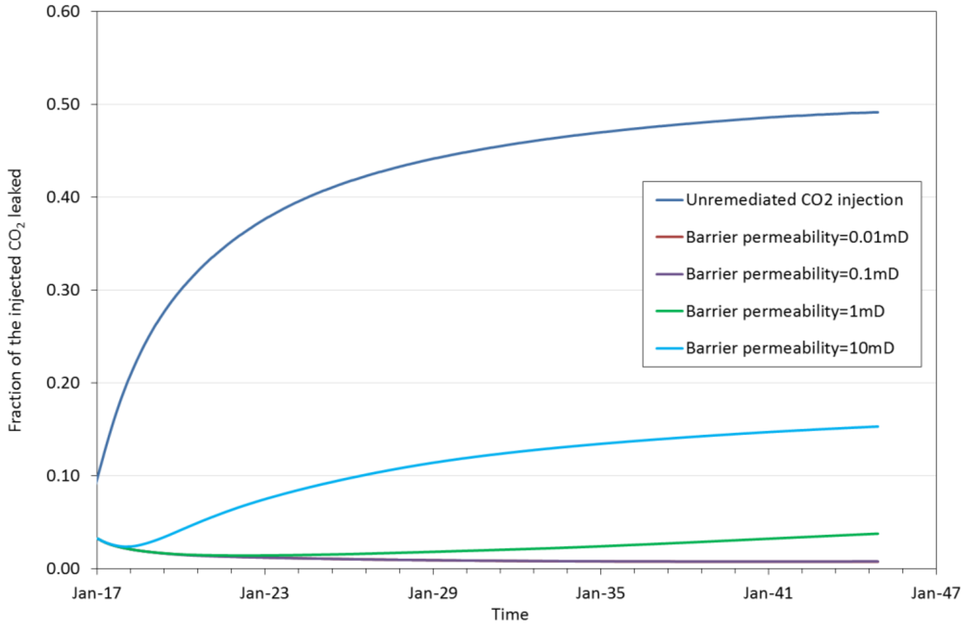
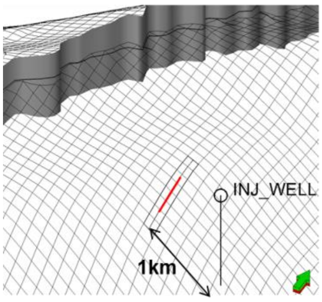


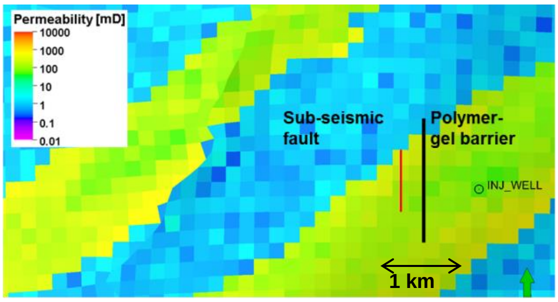
Figure 7. *Fraction of the injected CO_2 that could have leaked into the shallow aquifer for different cases of polymer-gel barrier permeabilities during the post-remediation period.*

2.2.2 Scenario 2: Inclined polymer-gel remediation barrier layout

Similar to the previous scenario, a sub-seismic vertical fault was introduced in the model at a distance of 1km away from the injection well (INJECTOR), located at the flank of the anticline (Figure 8). The fault has a lateral dimension of 800m×2m and assumed to be non-sealing, with a uniform vertical permeability of 10,000mD. In this scenario, however, it was assumed that the sub-seismic fault has a shorter vertical span (approximately 380m) such that it does not cut through the entire reservoir formation. Similar to Scenario 1, no appreciable formation displacement between the two sides of the fault is assumed.



(a)



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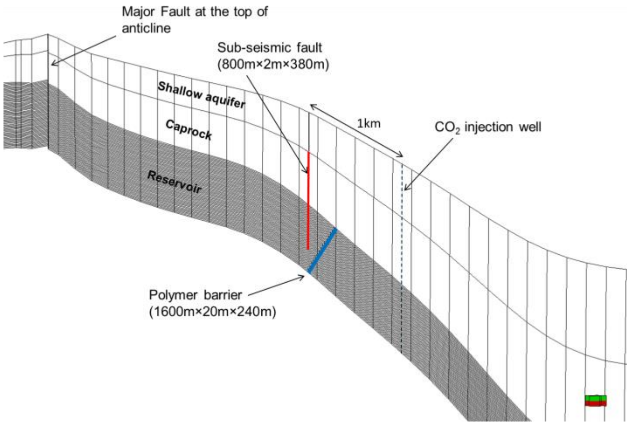


(c)

Figure 8. *(a) The grid refinement representing the sub-seismic fault feature (800m×2m), located 1km away from the injection well, and the polymer-gel barrier (1600m×20m); (b) permeability attribution and position of the polymer-gel barrier between the injection well and the sub-seismic fault at the top of the storage reservoir; (c) cross-sectional view showing the local grid refinement representing the sub-seismic fault feature in red, and the vertical polymer-gel barrier in blue.*

The simulation of CO_2 injection in the saline aquifer was similarly carried out at a rate of 1Mt/year, for a total period of thirty years comprising three stages: initial CO_2 injection until leakage detection, polymer-gel injection (remediation), and post-remediation CO_2 injection. The leakage detection threshold assumed was 5,000 tonnes of free CO_2 in the shallow aquifer (Benson, 2006).

Once the leakage through the sub-seismic fault was detected, CO_2 injection was stopped for a period of six months, at the end of which permeability reduction in the reservoir due to polymer-gel injection is implemented. The polymer-gel barrier was assumed to have a region of influence with a dimension of 1,600m×20m×240m and with the closest distance to the fault being approximately 100m, as illustrated in Figure 8. This scenario was considered in order to test a different layout of polymer-gel injection and resulting barrier in terms of its orientation with respect to the leaky fault.

2.2.2.1 CO_2 plume migration results

With the barrier in place, CO_2 injection was then re-started for the remaining period of the injection simulation at a rate of 1Mt/year, representing the post-remediation period. Figure 9 illustrates the distribution of free CO_2 after: (a) 5 years of simulation (January2020); (b) 9 years of simulation when leakage was detected and CO_2 injection was stopped (February 2024); (c) 9.5 years of simulation when remediation was completed (August 2024); (d) 15 years of simulation (January 2030); (e) 20 years of simulation (January 2035); and (f) 30 years of simulation

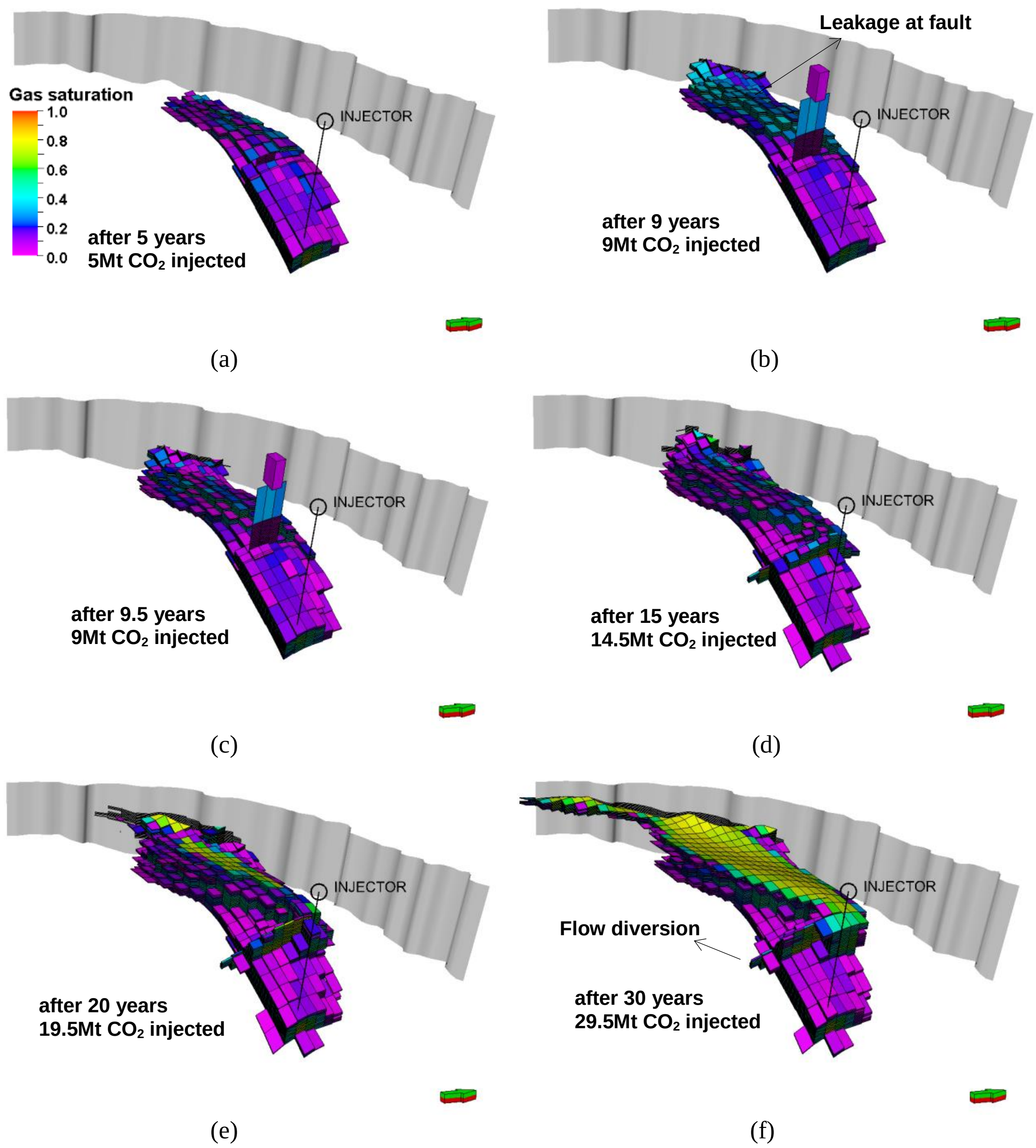
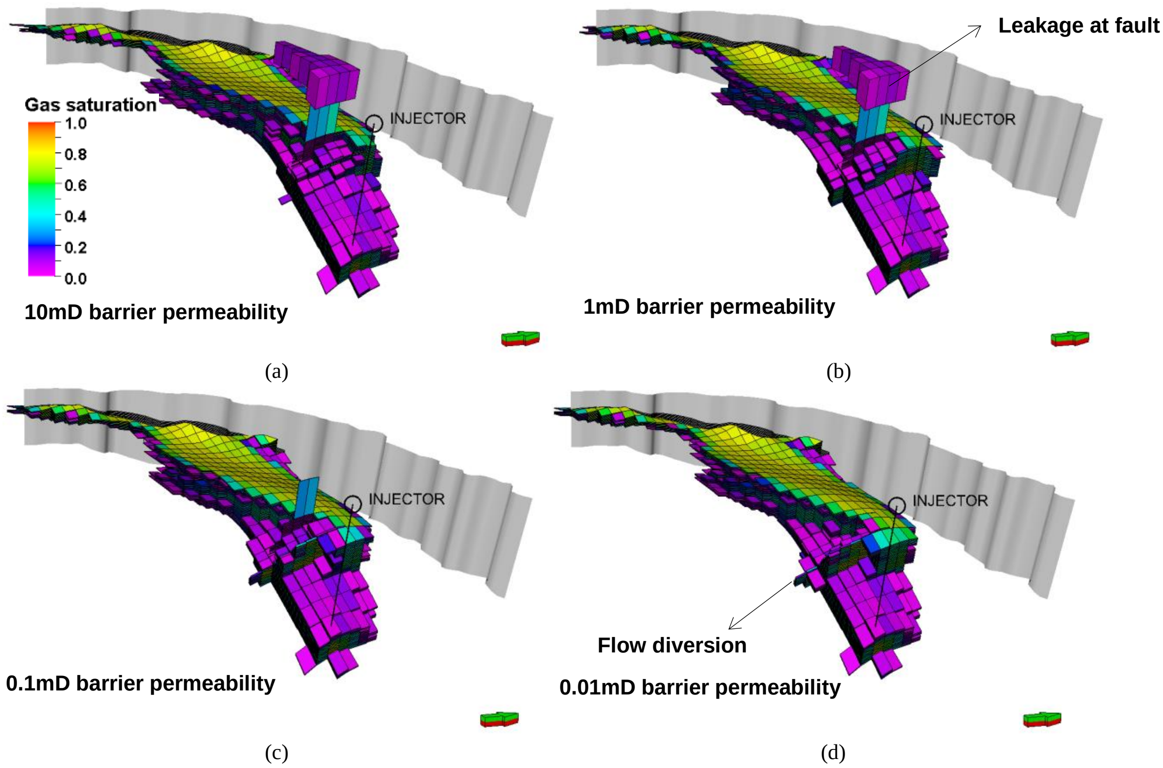


Figure 9. *Distribution of free CO_2 after: (a) 5 years of simulation (January 2020); (b) 9 years of simulation when leakage was detected and CO_2 injection was stopped (February 2024); (c) 9.5 years of simulation when remediation was completed (August 2024); (d) 15 years of simulation (January 2030); (e) 20 years of simulation (January 2035); and (f) 30 years of simulation (January 2045).*

(January 2045). The results suggest that the leakage has been effectively remediated and flow diversion of the CO_2 plume is achieved. Considering the much slower leakage rate, and that a fixed detection threshold is used for this scenario, leakage is detected much later as compared to Scenario 1.

2.2.2.2 Sensitivity analysis for the effect of permeability reduction on flow diversion

Different permeability values at the location of the polymer-gel barrier were tested in the model, ranging from 0.01-10mD. This considers 2-5 orders of magnitude of permeability reduction for the channel region (with an average horizontal permeability of 3000mD), and 0-3 orders of magnitude of permeability reduction for the inter-channel region (with an average horizontal permeability of 10mD). The free CO_2 plume distributions at the end of the thirty years injection period, as illustrated in Figure 10, suggest that leakage through the fault continues during the post-remediation period at a small rate when the barrier permeability is >0.1mD. For permeabilities below this value, the plume is effectively diverted away from the fault.



(a) (b) (c) (d)

Figure 10. *Plume distribution at the end of the 30 year simulation period when the permeability of the polymer–gel barrier is: (a) 10mD; (b) 1mD; (c) 0.1mD; (d) 0.01mD.*

Figure 11 illustrates the mass of cumulative CO_2 that could leak into the shallow aquifer for the thirty years of the simulation period. The simulation indicates that, for example, leakage reduction achieved after thirty years of simulation lies in the range of 18% to 90% (*i.e.* is reduced by ~0.1Mt to ~0.9Mt) for this scenario. Hence, leakage through the fault continues at a lesser rate during the post-remediation period for all the barrier permeabilities considered. As in Scenario 1, in the cumulative total mass of CO_2 leakage indicated in Figure 11, the free CO_2 accounts only for one fraction of the total CO_2 leakage. The detection limit of 5,000tonnes of free CO_2 corresponds to 86.3kt of the cumulative mass of total CO_2.

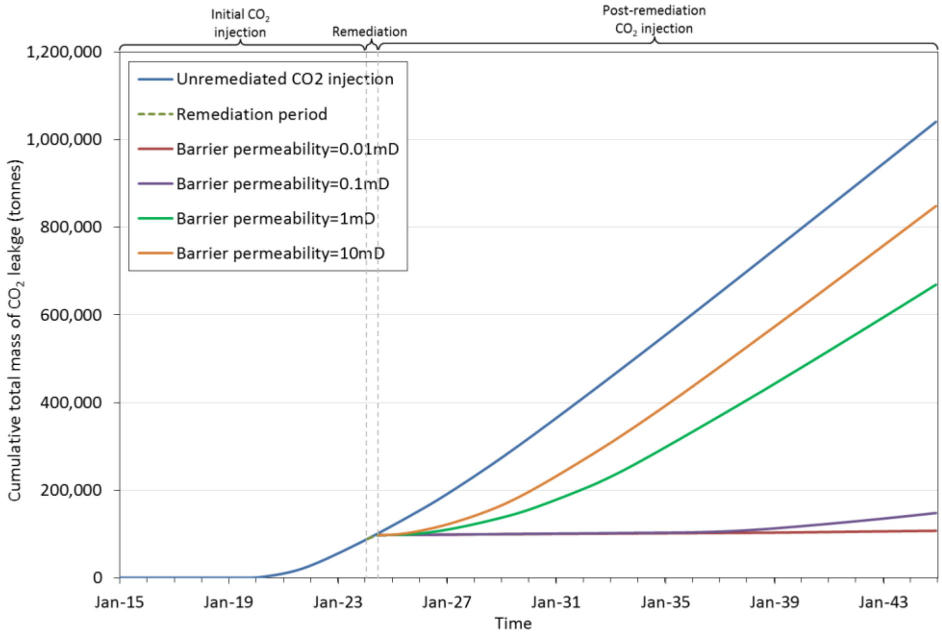


Figure 11. *Cumulative mass of total CO_2 (which includes free, dissolved and trapped components) that could leak in to the shallow aquifer for different cases of polymer-gel barrier permeabilities.*

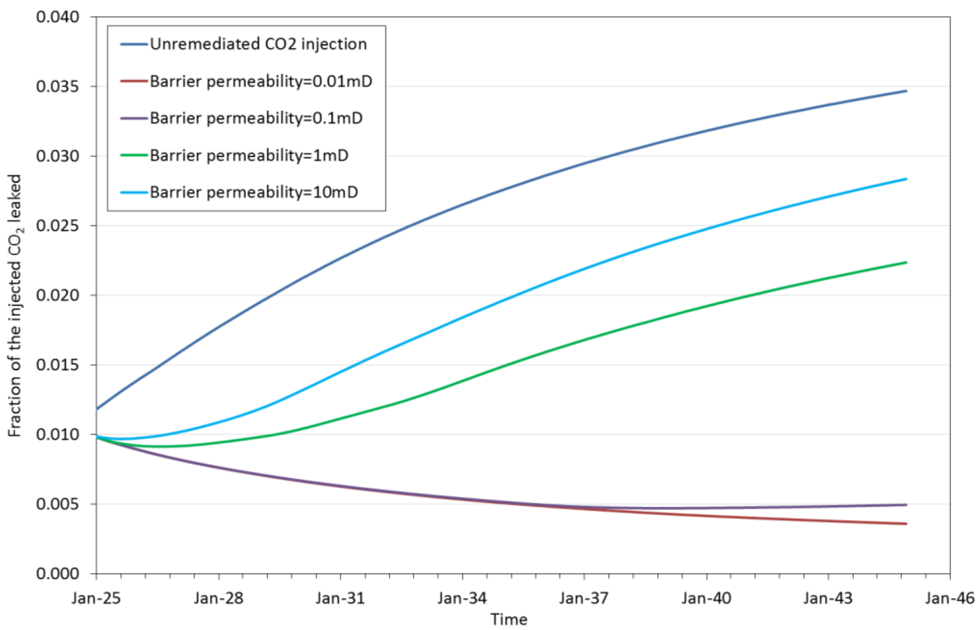


Figure 12. *Fraction of the injected CO_2 leaked into shallow aquifer during post-remediation period.*

Figure 12 illustrates the fraction of the injected CO_2 that could leak in to the shallow aquifer during post-remediation period for different barrier permeabilities. The results show that for the case of un-remediated CO_2 injection, up to 3.5% of the injected CO_2 can be expected to leak; whereas for the remediated cases, the amount of CO_2 leakage is reduced to 0.4-2.7% of the injected CO_2, depending on the range of barrier permeabilities considered.

2.3 Remarks on polymer-gel remediation

Based on polymer-gel characterisation and permeability reduction results obtained from the laboratory experiments carried out in MiReCOL, a numerical model of a fluviatile saline aquifer was set up to assess the effectiveness of polymer-gel injection in diverting the flow of CO_2 plume away from a leaking sub-seismic fault within the storage reservoir. Two scenarios were defined based on different vertical extent of the sub-seismic fault as well as different layouts of the polymer-gel injection and eventual barrier position.

The modelling results obtained for a thirty-year simulation period in this study suggest that undesired CO_2 plume migration can be potentially prevented using polymer-gel solutions for flow diversion. Sensitivity analyses carried out suggest that the polymer-gel barrier is likely to be more effective if the resultant barrier permeability is less than 1mD.

Currently, the polymer injection modelling is being progressed further within the MiReCOL project towards remediation of leakage through faults and the caprock. Well layouts, volume of gel needed, the spatial extension of remediation, response time and longevity of remediation will be further investigated and reported in a future report [2].

3 FOAM INJECTION AS FLOW DIVERSION OPTION

In order to apply foam to reduce leakage of CO_2 in a underground reservoir, a well is drilled near the leakage site and a solution of surfactant and brine is injected. The presence of CO_2 will then cause the formation of foam, which will reduce the mobility of the CO_2 phase thereby minimizing further leakage.

The plugging effect of foam treatment depends on geology, position and type of leakage, injected surfactant volumes, surfactant concentration, adsorption, foam strength and foam stability. The main purpose of the study is to explore ranges of some of these factors and to quantify their impact on continued leakage.

In this study we consider containment of a possible leakage of CO_2 under a structural spill point.

3.1 Foam modelling

The background explanation of the use of foam is given in earlier MiReCOL reports (Nabzar et al., 2015; Wasch et al., 2015). Foam is used in the oil & gas industry for mobility control of gas sweep during enhanced oil recovery. In this case surfactant is injected together with the water phase, and foam is generated when gas contacts the surfactant/brine solution. The desired effect is to reduce the mobility of the gas, forcing the injected gas to take alternative paths thus contacting more oil as well as delaying gas breakthrough in the production wells. Foam can also be used to reduce gas coning/cresting at producing wells. However due to various difficulties, foam has not yet been widely implemented on a field scale for enhanced oil recovery, with the possible exception of the Foam-Assisted Water Alternating Gas project on the Snorre field.

The present piece of work investigated an example of the use of foam as a plugging agent for leaking CO_2.

[2] This will be MiReCOL report D6.3.

3.1.1 Modelling foam and prediction of its behaviour

In order to perform an assessment of the effectiveness of foam as a plugging medium it was decided to model scenarios in a numeric simulator. This is challenging due to several reasons, as follows:-

- The interpretation of laboratory measurements can be challenging,
- Field data used is uncertain, not least because of the effects of reservoir heterogeneity,
- Up-scaling to field scale is not well understood,
- The macroscopic numerical model is complicated and approximate in itself.

As a result the prediction of field-scale foam behaviour is indeed challenging and quite uncertain, in particular for assessment of the plugging properties of foam.

The factors affecting the behaviour of foam in a reservoir include:-

- The surfactant type,
- Temperature,
- Salinity,
- The lithology and rock surface properties,
- Liquid properties,
- Flow rates,
- Wettability,
- The surfactant concentrations achieved,
- The rates of component exchange.

In turn all of the above can affect:-

- Adsorption of the surfactant onto the formation,
- The foam strength achieved,
- The stability/durability of the foam.

Foam decay is obviously an important issue. Within the reservoir foam does not form a solid material, but ideally should retain its plugging effect for a relatively long time. Ideally the stability of foam should compete with the time scales for CO_2 dissolution and CO_2 capillary trapping. Its stability is affected by non-equilibrium processes such as component exchange, viscous forces and saturation changes, which lead to degradation of the foam. This area is far from understood and it is difficult to find data in literature on the durability of foam.

AOS14 foam was adopted for this analysis, which has moderate foam strength at CO_2 storage conditions. For this work a numerical model was developed using the foam model in Eclipse 100 (Schlumberger). The following functional form was used:-

Gas relative permeability $\boldsymbol{k_{rg\_foam}} = \frac{\boldsymbol{k_{rg}}}{1+(\boldsymbol{M_r F_s(c) F_w(S_w)})}$

(note that rate and oil dependencies are also possible)

Reference gas mobility reduction factor = $\boldsymbol{M_r}$. Values of 6 and 20 were used.

Surfactant dependence $\boldsymbol{F_s(c)} = \left(\frac{c}{c_{ref}}\right)^{\alpha_s}$, where c is surfactant concentration.

Reference surfactant concentration for strong or weak foam $\boldsymbol{c_{ref} = 0.1\%}$

Exponent $\boldsymbol{\alpha_s = 1}$

Water saturation dependence $\boldsymbol{F_w(S_w) = \frac{1}{2} + \frac{1}{\pi} arctan\left(\alpha(S_w - S_w^*)\right)}$

Dry out weighting factor $\boldsymbol{\alpha = 8}$

Dry out water saturation $\boldsymbol{S_w^* = 0.4}$

Adsorption and desorption of surfactant is a function of foam concentration, with alternative maximum values of 0.1 mg/g and 0.5 mg/g being used.

Decay of foam is given by specifying a half-time (not well documented in the literature), and values of 1 day, 45 days, and 365 days were used.

Note that since the injection point is assumed to be deeper than 800m, the CO_2 is in the dense phase and the foam strength is significantly reduced compared with foam strength for gaseous CO_2 (Aarra *et al*., 2014). Also, the water mobility was seen to be significantly reduced for this foam system.

3.1.2 Generic simulation model

A generic numeric model was prepared to simulate CO_2 leakage under a spill point, as shown in Figure 13. The active model measured 3.35 km x 0.6km x 300m with block dimensions of 23.7m x 20m x 6m. The reservoir properties were homogeneous throughout the model, with porosity = 0.3 and permeability = 500mD. The generic relative permeabilities used are shown in Figure 14 and no capillary pressure was applied. Water and gas were the only components modelled.

The depth of the top of the reservoir was defined as 1000m and open boundary conditions were implemented at the ends of the model by means of passive pressure relief wells W1 and W2.

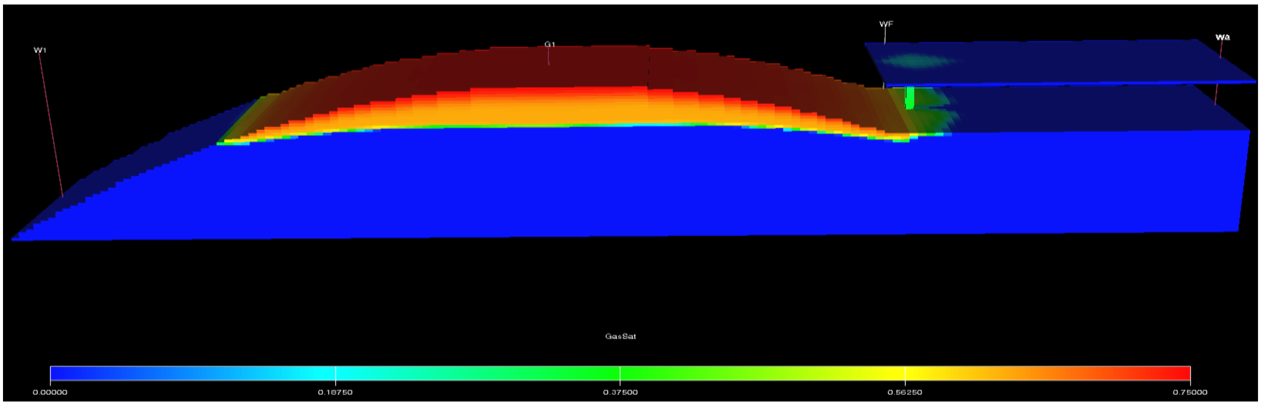


Figure 13. *Generic simulation model of CO_2 spill-over.*

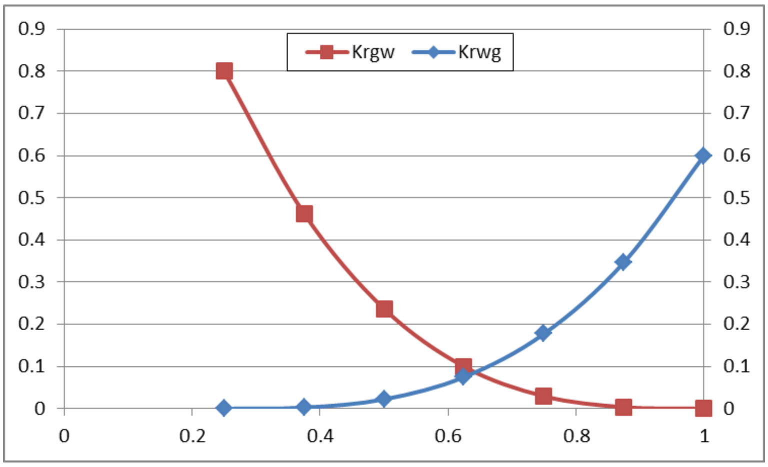


Figure 14. *Relative permeabilities.*

The simulation was composed of 3 stages. Firstly 1Mt/y of CO_2 was injected at 4,000 sm^3/d into the top of the anticline for 7.5 years (via injector G1), resulting in the onset of leakage under the spill point at the right-hand side as shown in Figure 13 (note – sm3 denotes standard conditions).

In stage 2 surfactant was introduced via a horizontal well WF located at the spill-point as shown in Figure 15. A 0.5% wt. solution of surfactant and brine was injected at 1,000 rm^3/d for 0.25 year (rm^3 denotes reservoir conditions), amounting to 450,000 kg of surfactant in total. (In this preliminary model a conduit up to small shallower aquifer was included to assist leakage measurement, but this was subsequently removed).

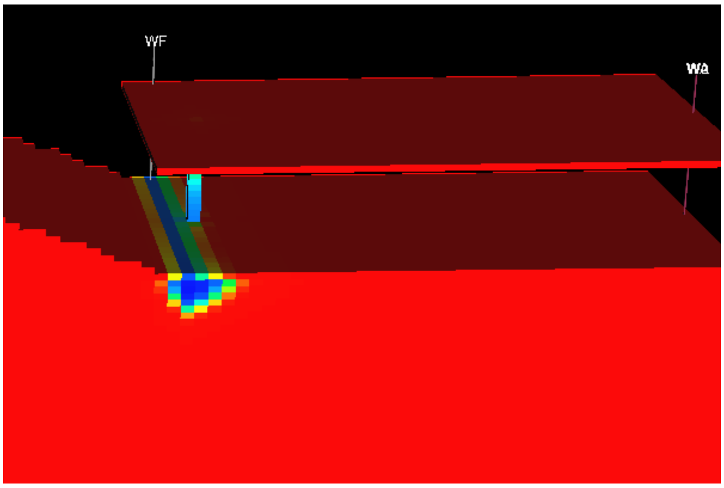


Figure 15. *Preliminary arrangement at the spill point showing the surfactant injection well and a temporary secondary aquifer (the colours show the gas mobility factor, dark blue= 0, red = 1.0)*

In the third stage, CO_2 injection into the anticline was continued for another 12 years at the same injection rate as before, without further injection of surfactant. The final state of CO_2 saturation in the model reservoir is shown in Figure 16, which indicates that the foam created provides resistance, if not a complete block, to the migration of CO_2.

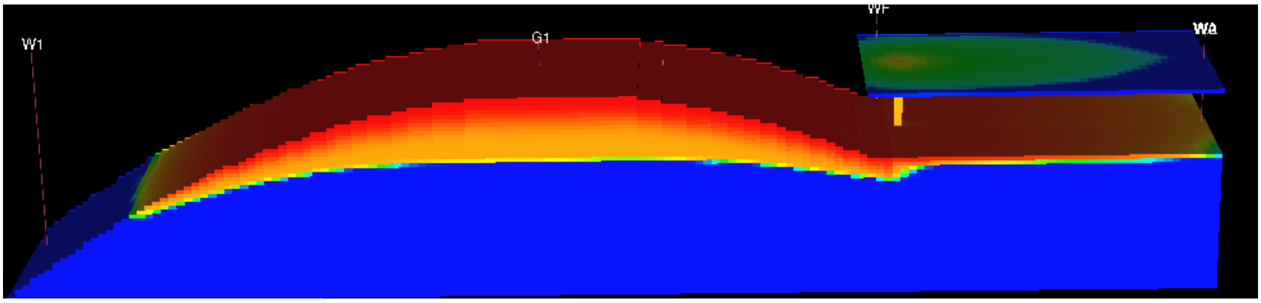


Figure 16. *Final state of the generic reservoir showing gas (CO_2 saturation blue=0, red=1).*

Several additional simulations were run in which the maximum adsorption factor, the reference gas mobility reduction factor and the foam decay half-life were varied individually. The results in Figure 17 and Figure 18 show that the maximum adsorption factor and the reference gas mobility factor had significant effects on the leakage rate, while the results were insensitive to the foam decay half-life.

This foam model was used hereafter in further simulations to assess the practical application of foam to mitigation of CO_2 leakage.

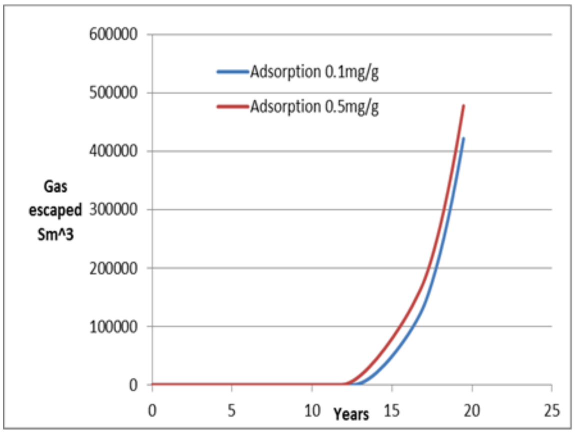


Figure 17. *Constant reference mobility reduction factor M=6*

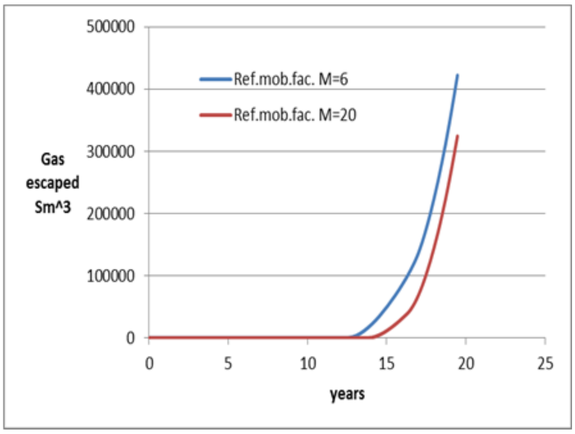


Figure 18. *Constant adsorption factor=0.5mg/g*

3.2 Assessment of capability of foam to mitigate CO_2 migration

The same generic model was used to support a series of flow simulations in Eclipse to assess the efficacy of injected foam to reduce the unwanted migration of injected CO_2 underground.

This forms input to relative comparison of mitigation measures that will be conducted in WP11.

3.2.1 Simulation model

The same model was used as in Section 3.1.2 on modelling foam, i.e. a 2-dimensional anticline with a spill-point, and largely the same injection and production strategy was used, i.e. injection of 4000 rm^3/d CO_2 for 7.5 years, then injection of the surfactant solution, then continued injection of CO_2 for the remainder of 19.75 years.

Note that it was decided not to stop CO_2 injection when surfactant injection was begun, as continued CO_2 injection is a more demanding scenario and is expected to be the Operator's preferred choice (note that the alternative of re-routing the CO_2 to another storage reservoir, or other contractual options are likely to be much more expensive than a comprehensive mitigation programme).

In order to derive quantitative data on leakage and reduction thereof, it was necessary to divide the model into regions for which volumetric data can be extracted from the numerical simulator. In order to make this as straightforward as possible, the secondary reservoir and upward conduit in the previous model were removed. In addition the main part of the reservoir was divided onto two Fluid-in-Place Regions, using the line of the horizontal injection well WF as the boundary, as shown in Figure 19. The quantities of CO_2 (gas) flowing from Region 1 to Region 2, i.e. the leakage past the surfactant injection well, could be found in each periodic report and are the most important data source. Note that the current volumes of the regions are of no interest because they are affected by the injection and production volumes of CO_2 and water.

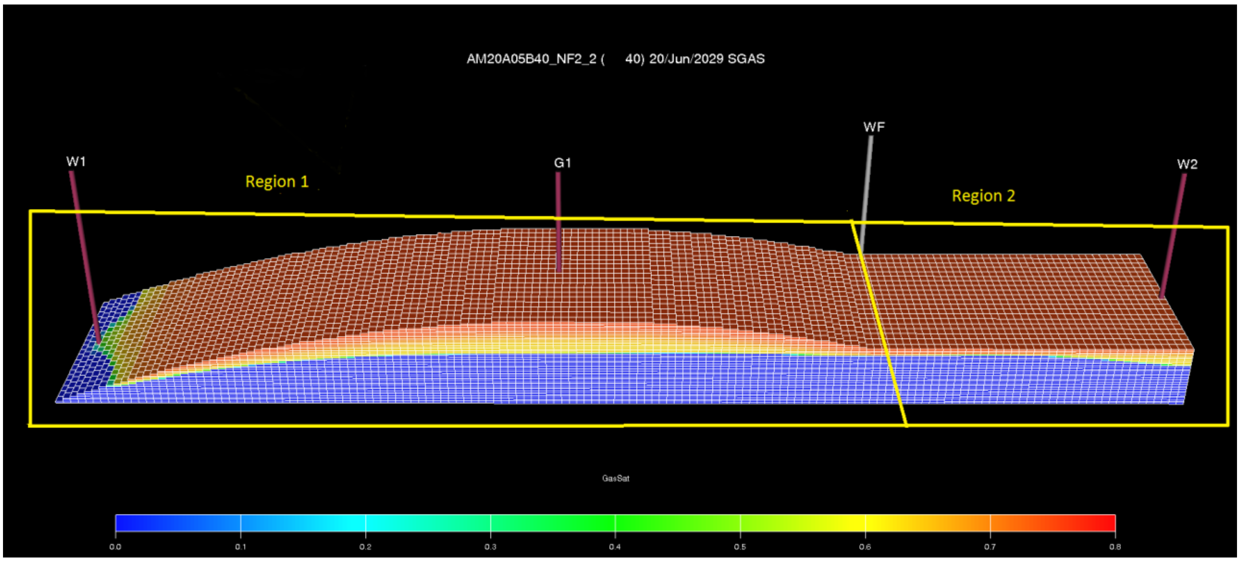


Figure 19. *Regions applied to quantify leakage volumes.*

A **Base Case** simulation was run 4000 rm^3/d CO_2 injection at the top of the anticline (via well G1) and zero surfactant injection. This gave the uncontrolled amount of leakage over the 19.75 years considered, against which the various mitigation measures were measured.

The build-up of uncontrolled "leakage" or migration into Region 2 is shown in Figure 20.

A **Reference Case** mitigation scenario was chosen, utilising a middle set of foam parameters from the foam modelling work described in Section 3.1.2, with the following parameters:-

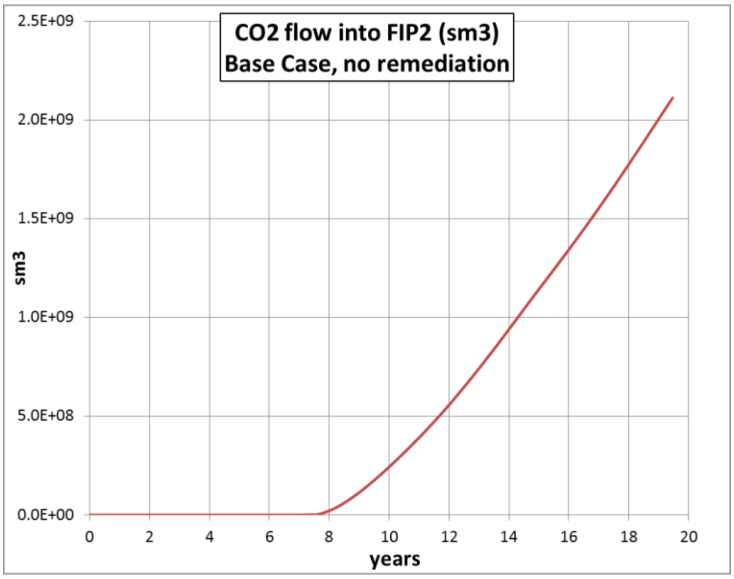


Figure 20. *Uncontrolled leakage in Base Case.*

- Reference CO_2 mobility reduction factor = 20,
- CO_2 adsorption = 5 mg/g,
- Foam half-life = 40 days,
- Operational parameters:-
  - Injected surfactant concentration = 5kg/sm^3 water,
  - Duration of surfactant injection = 90 days,
  - Surfactant solution injection rate = 1000 rm^3/d,
  - CO_2 injection rate = 4000rm^3/d.

Variations on the operational parameters were simulated in order to investigate what could be achieved in a leakage-control situation, on the basis of the adopted foam characteristics.

Two measures of mitigation were used for comparison, namely:-

- The reduction of leakage as a percentage of the Base Case leakage and
- The percentage reduction of leakage per million kg of surfactant injected, which gives a measure of unit (cost-) effectiveness.

3.2.2 Cases investigated

The main cases simulated plus their results are given in Appendix.1.

3.2.2.1 Surfactant injector orientation

Three initial variations of the surfactant injection well configuration were run, namely a vertical well perforated only in the top layer of the reservoir z=17, a horizontal well in layer z=18 (as in Section 3.1.2) and a horizontal well at the top of the reservoir in layer z=17. The horizontal wells were perforated on all blocks across the reservoir.

The results showed 98% leakage with the vertical well, 93% with the z=18 horizontal well and 91% with the z=17 horizontal well. The differences were easily explained by the lack of horizontal foam coverage provided by the vertical well and CO_2 over-run (i.e. CO_2 passing above) the horizontal well at z=18. These effects can be seen in the pictures of gas CO_2 saturation in Figure 21, Figure 22 and Figure 23.

It was decided that all further simulations would be based on a horizontal surfactant injection well located primarily at z=17, but with an alternative well at z=18 as a sensitivity.

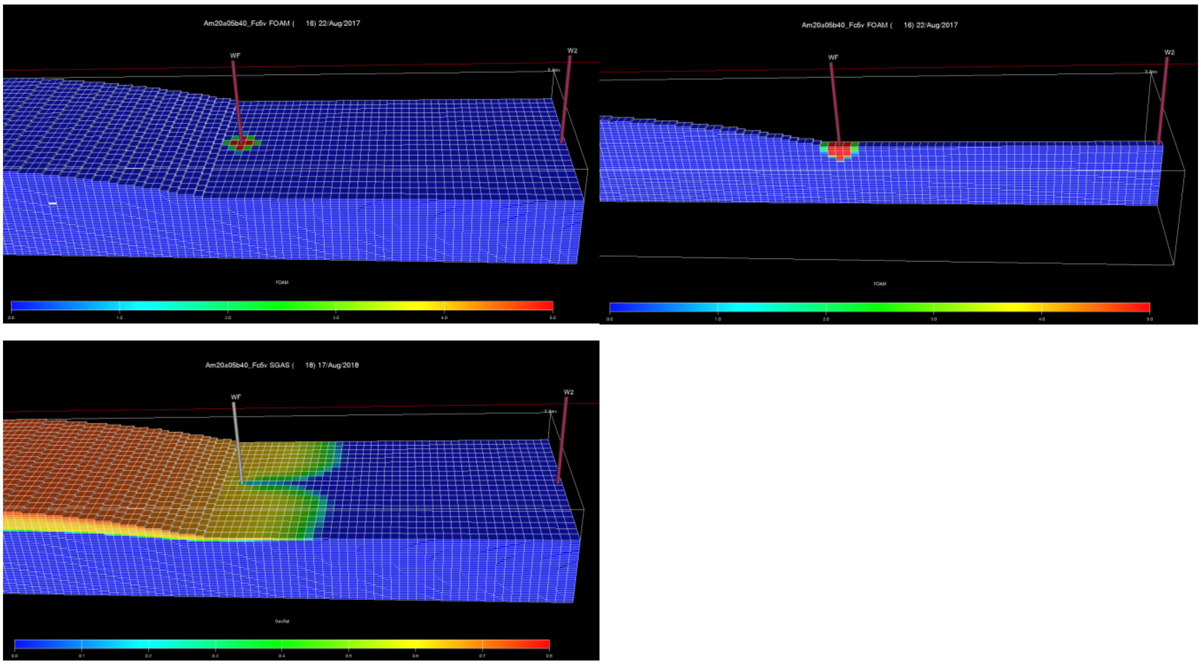


Figure 21. *Vertical well, a) and b) foam concentration and c) CO_2 saturation all at 7.6 years.*

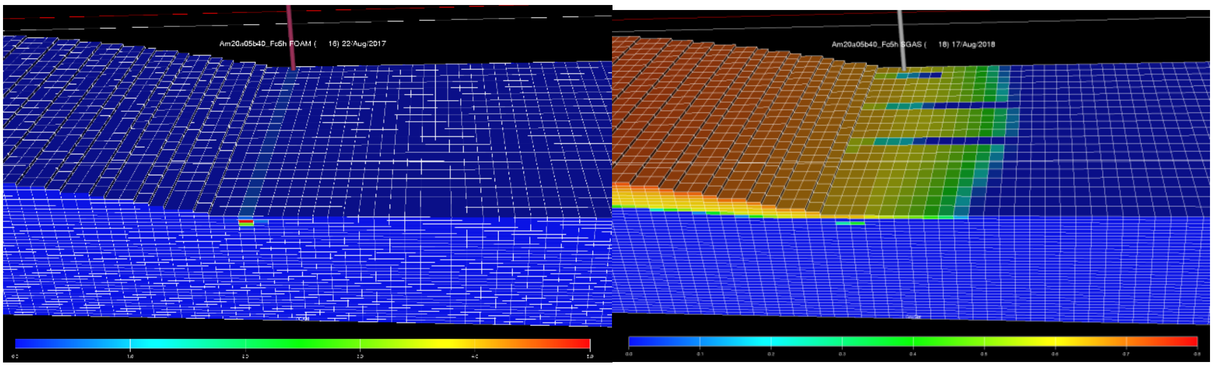


Figure 22. *Horizontal well at z=18, a) foam concentration at 7.6 years and b) CO_2 saturation at 8.6 years.*

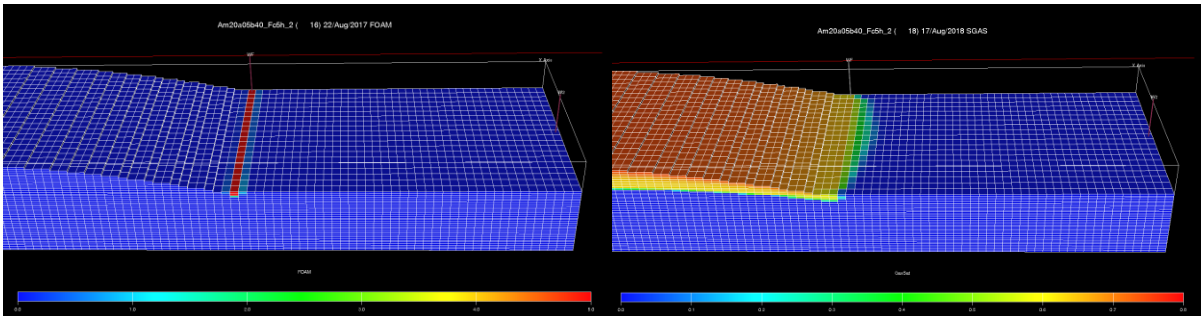


***Figure 23.** Horizontal well at z=17, a) foam concentration at 7.6 years and b) CO_2 saturation at 8.6 years*

3.2.2.2 Surfactant concentration

In addition to the original simulations using 5kg/sm^3 surfactant concentration, additional cases were run with 50 kg/sm^3 and 100 kg/sm^3 and all other parameters unchanged.

Pictures of the foam and CO_2 saturations in Figure 24 and Figure 25 show that the cross-sectional area containing the foam is quite small in all cases considered, with the result that the CO_2 is blocked only for a short period, but soon under-runs the foam plug.

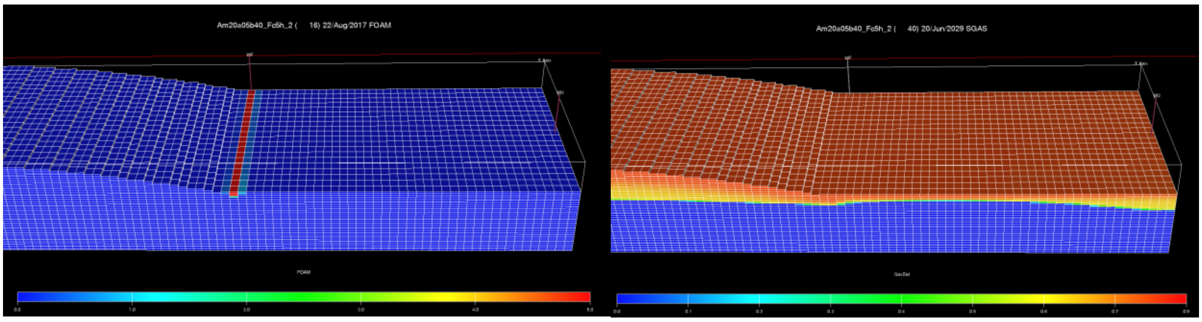


***Figure 24.** 5kg/sm3 surfactant, foam concentration at 7.6 years and CO_2 saturation at 19.7 years (Reference Case).*

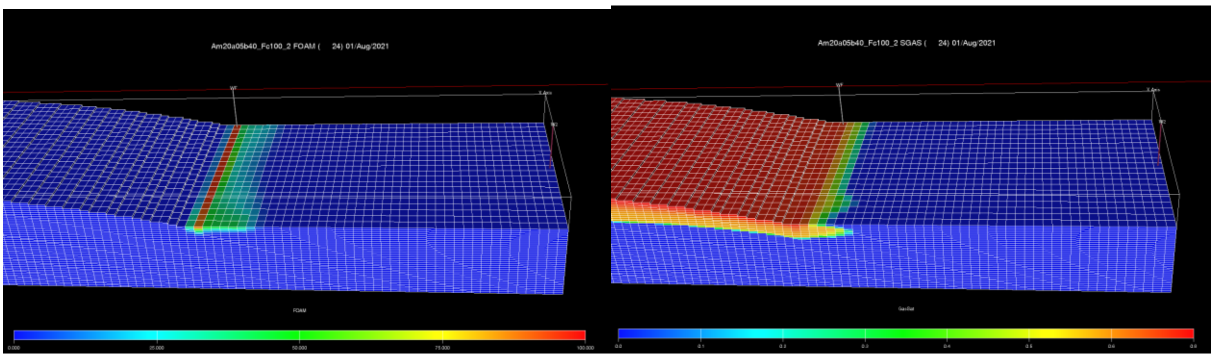


***Figure 25.** 100 kg/sm^3 surfactant, foam concentration and CO_2 saturation at 11.5 years. This is the point of under-run occurring and the CO_2 continues to occupy all of the topmost layers.*

3.2.2.3 Surfactant injection duration

From the results of Section 3.2.2.2 it appeared that a foam "plug" of greater volume would be beneficial, instead of greater concentration. Therefore variations on the duration of surfactant injection were tried, starting from 0.25 year in the Reference Case, to 1 year, 5 years and 12.25 years.

It can be seen from Figure 24 and Figure 26 to Figure 28 that with long injection durations (i.e. greater injected volume) the foam plug is much larger and the total leakage is reduced. Obviously the amount of surfactant injected increases proportionally with the duration of injection, i.e. 50 times after 12.25 years injection.

Figure 28 shows clearly that under-run is the main mechanism for CO_2 to pass the foam plug.

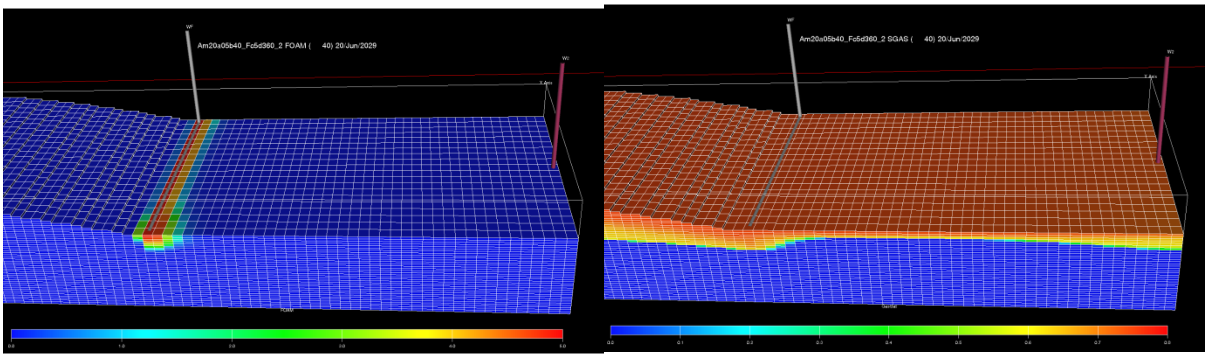


Figure 26. *Surfactant injection for 1 year, showing a) foam concentration and b) CO_2 saturation at 19.7 years.*

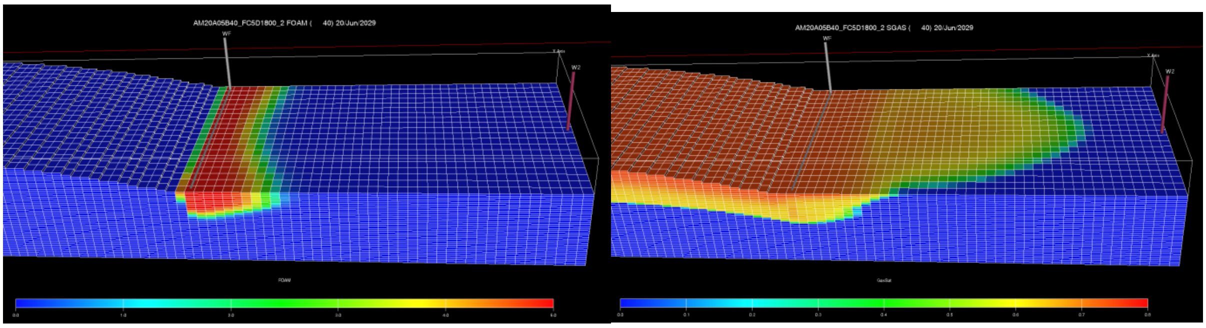


Figure 27. *Surfactant injection for 5 years, showing a) foam concentration and b) CO_2 saturation at 19.7 years.*

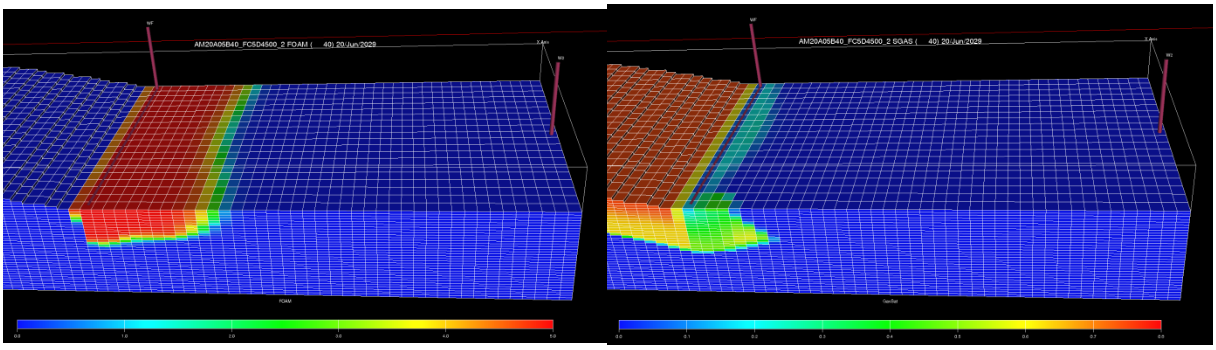
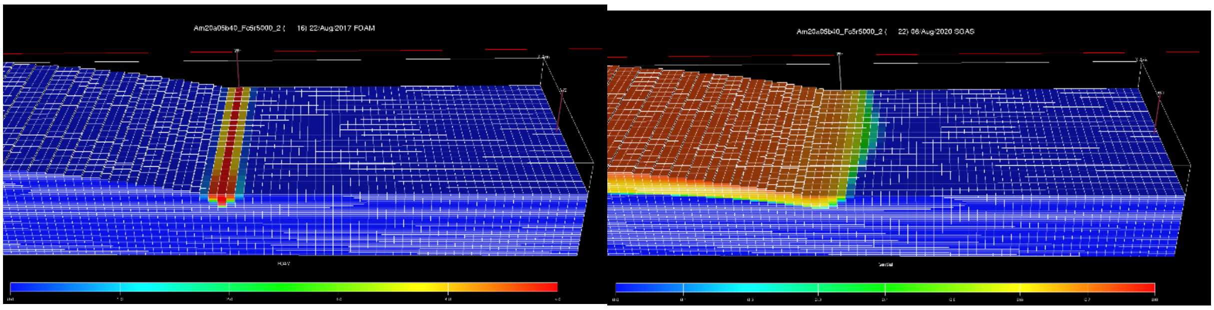


Figure 28. *Surfactant injection for 12.25 years, showing a) foam concentration and b) CO_2 saturation at 19.7 years.*

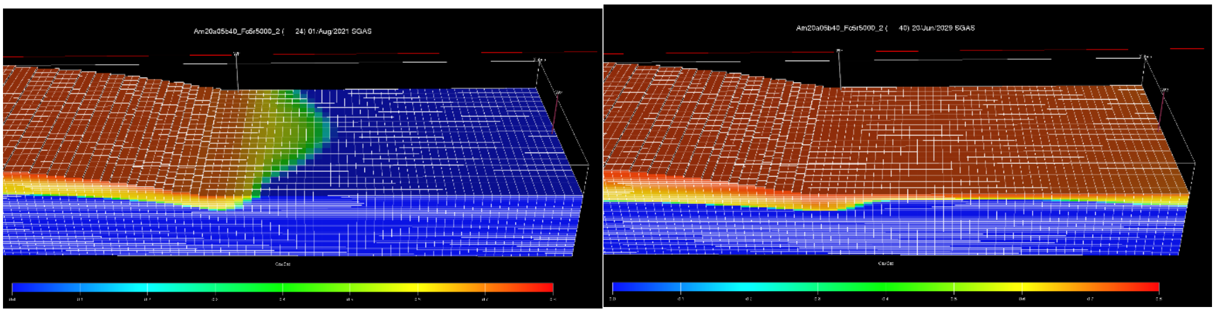
3.2.2.4 Surfactant injection rate

As an alternative to injecting for a longer period is to inject surfactant at a higher rate, in order to build a large plug more quickly. In addition to the Reference Case rate of 1,000 rm^3/d, two other rates were tried, namely 5,000 rm^3/d and 10,000 rm^3/d, all with 0.25 year injection.

The pictures in Figure 29 show that the increased injection rate forms a more substantial plug which holds back the CO_2 for four years, when large-scale under-run occurs. It can be seen that the effect is similar to injecting for a longer period.



a)



b)

Figure 29. *Surfactant injection rate at 5,000 rm^3/d for 0.25 year, a) initial foam concentration achieved, b) CO_2 restrained at 3 years after surfactant injection, b)under-run and break-through occurring 1 year later and d) final CO_2 saturation at 19.7 years.*

3.2.2.5 CO_2 injection rate.

A few alternatives for the CO_2 injection rate were simulated in order to demonstrate its effect on the leakage rate. The Reference Case used a value of 4,000 rm^3/d and in subsequent simulations values of 6,000 and 8,000 rm^3/d were tried.

3.2.3 Simulation results

The results of the simulations described above were depicted graphically, as shown in Figure 30 to Figure 33.

In Figure 30 it can be seen that very little improvement in blocking occurs with increased surfactant concentrations above 60 kg/sm^3. On the contrary Figure 31 and Figure 32 show that migration keeps falling with increasing surfactant injection duration and injection rate. This might be explained by the limited size of plug generated by increased surfactant concentration alone, without a larger volume of water to carry and spread the surfactant.

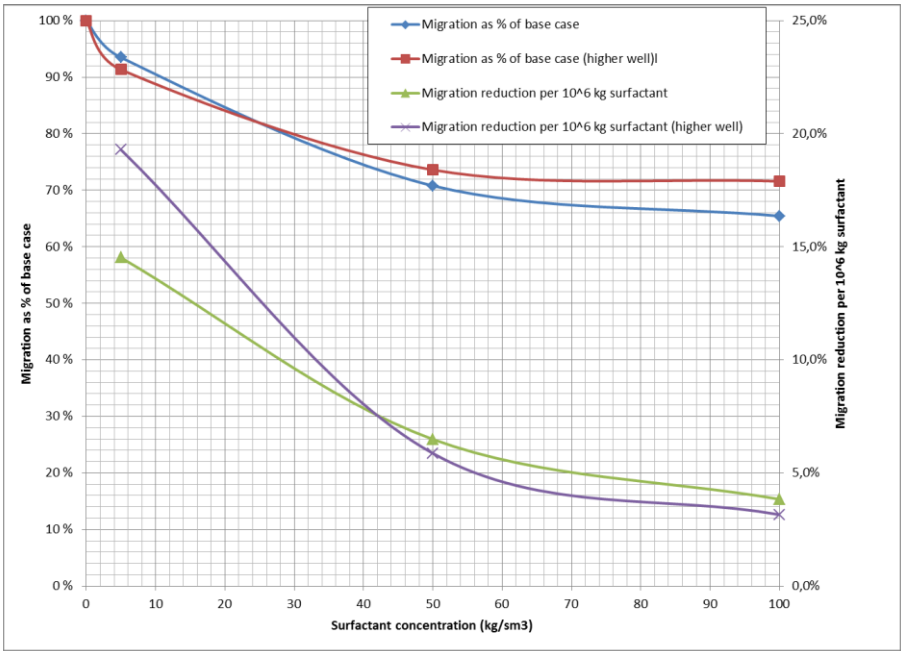


Figure 30. *Mitigation measures versus surfactant concentration.*

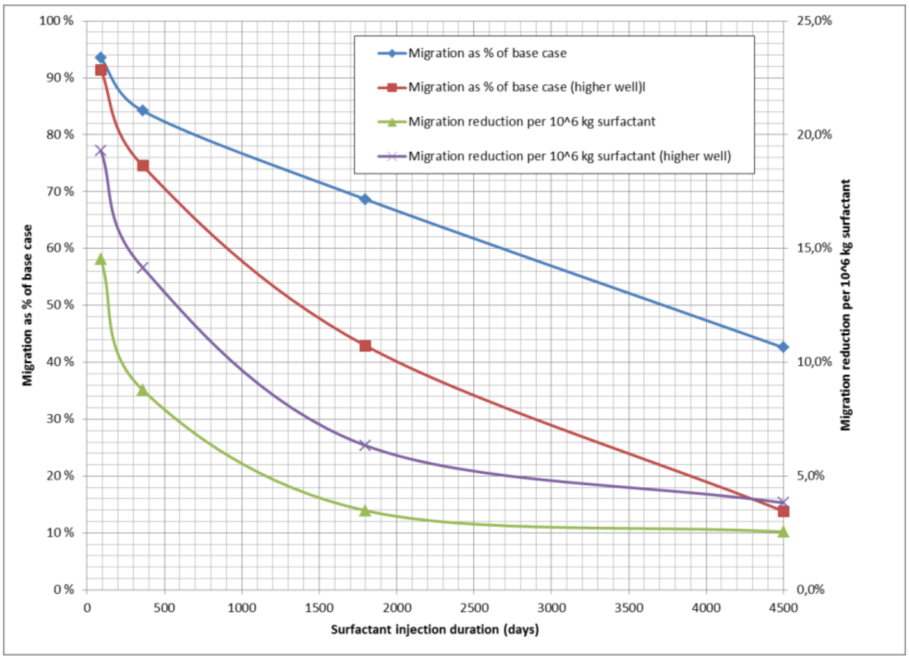


Figure 31. *Mitigation measures versus surfactant injection duration.*

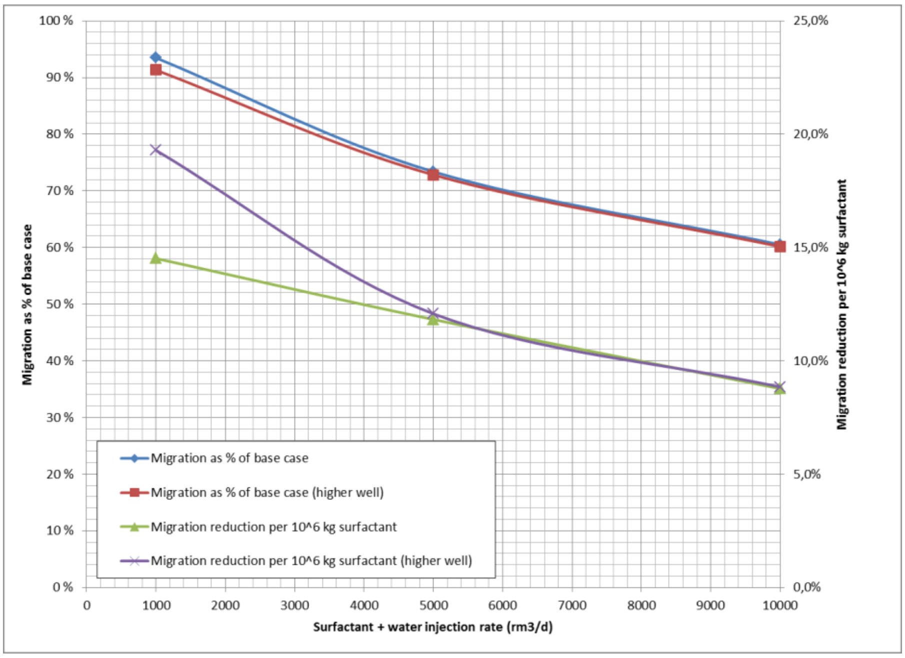


Figure 32. *Mitigation measures versus surfactant injection rate*

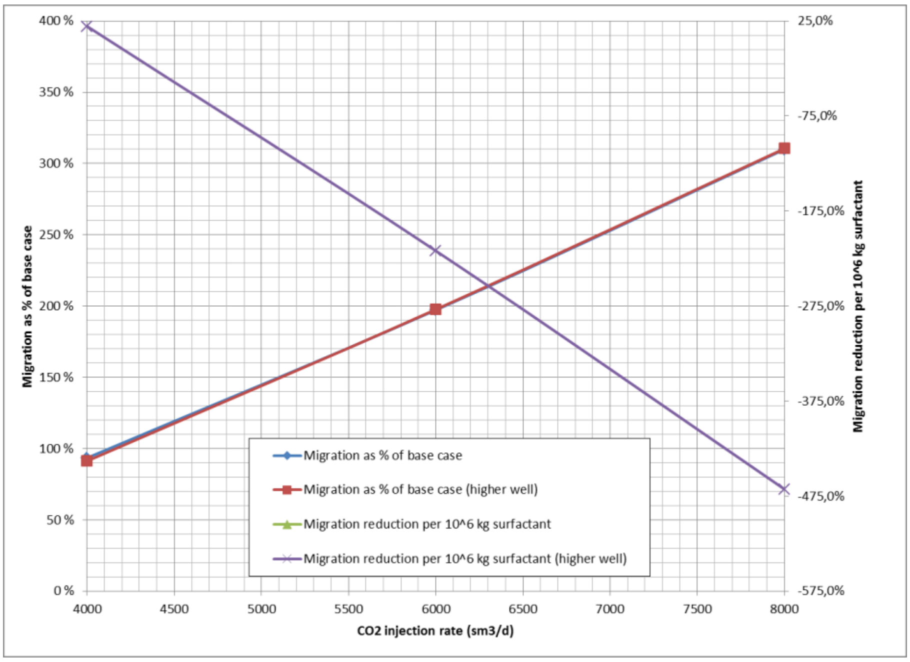


Figure 33. *Mitigation measures versus CO_2 injection rate*

Considering unit effectiveness (migration reduction per million kg of surfactant injected) it can be seen that CO_2 migration is reduced rapidly with the initial increase of all the parameters tested. However while this measure tends to level out with increasing injection concentration and injection duration (Figure 30 and Figure 31), it keeps decreasing with increasing injection rate (Figure 32).

From the two observations above it might be suggested that injection duration has the greatest single potential for increased leakage mitigation, since leakage can be reduced with longer injection without reducing its unit effectiveness.

Note also that since no effect was observed for the foam half-life in Eclipse simulations (Section 3.1.2), injecting surfactant over a longer period of time would help to counteract the assumed effects of foam degradation in a real reservoir.

Figure 33 shows the results for increased CO_2 injection rates where an almost linear increase in leakage is evident with a corresponding near-linear reduction in unit effectiveness. This was as expected.

In all cases, the mitigation of leakage is limited by under-run of the CO_2. This suggests that there might be potential improvement from additional injection of surfactant at lower depths in the reservoir to increase the vertical size of the foam plug.

3.2.4 Limited optimisation

A very limited exercise was performed to gauge the potential for optimising the reduction of leakage by simultaneously varying several of the parameters used.

1. The starting point is the Reference Case shown in Figure 24 which to repeat, utilised a surfactant concentration of 5 kg/sm^3, an injection rate of 1,000 rm^3/d and an injection duration of 0.25 year starting at 7.5 years into the simulation. Note the very small foam plug formed.
2. The next step was to increase the injection rate to 5,000 rm^3/d, as already described and shown in Figure 29. This generated a slightly larger foam plug, which delayed CO_2 breakthrough for three years.
3. In order to extend the duration of blockage an additional 0.25 year of surfactant injection at the same rate was implemented, commencing at 3 years after the start of the first injection period, i.e. at t=10.5 years. The results in Figure 34 show that an even larger foam plug was generated, which delayed the leakage, but was eventually under-ridden by the CO_2. Note also that the foam plug has a significant CO_2saturation, i.e. is not impermeable.
4. As an alternative to two discrete periods of surfactant injection, a continuous process was implemented. After the first 0.25 year injection period at 5,000 rm^3/d, injection continued for the remainder of the simulation at a reduced rate of 1,000 rm^3/d. The aim of this was to maintain the effectiveness of the foam plug and possibly extend its depth. The pictures in Figure 35 show that a somewhat massive foam plug was developed by the end of the simulation which succeeded to a large degree in preventing leakage of CO_2. The numerical results showed that the leakage had been reduced to 14% of the Base Case, but with a very low unit effectiveness of 3.6%. This result was the same as achieved earlier with 12.25 years injection at a constant 1,000 rm^3/d, suggesting that constant surfactant injection is more important than a high initial injection rate.

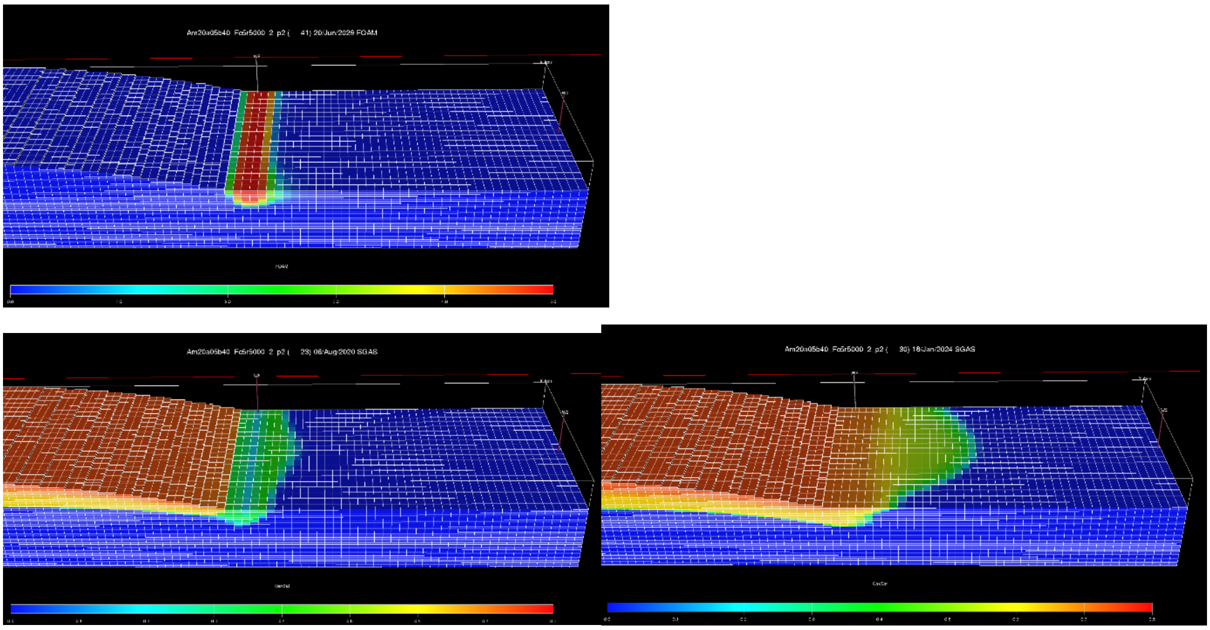


Figure 34. *Surfactant injection at 5,000 rm^3/d for 2x0.25 years, a) foam concentration at the end of 19.75 years, b) CO_2 concentration after the second surfactant injection period showing migration through the foam plug, c) CO_2 concentration 3.5 years later, showing under-run.*

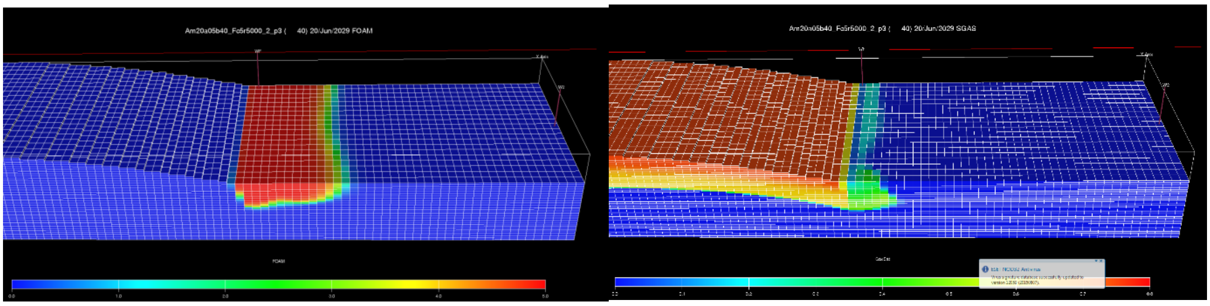


Figure 35. *Surfactant injection at 5,000 rm^3/d for 0.25 year followed by 12 years at 1,000 rm^3/d, a) foam concentration at the end of 19.75 years, b) CO_2 concentration at the end of 19.75 years showing almost complete blockage.*

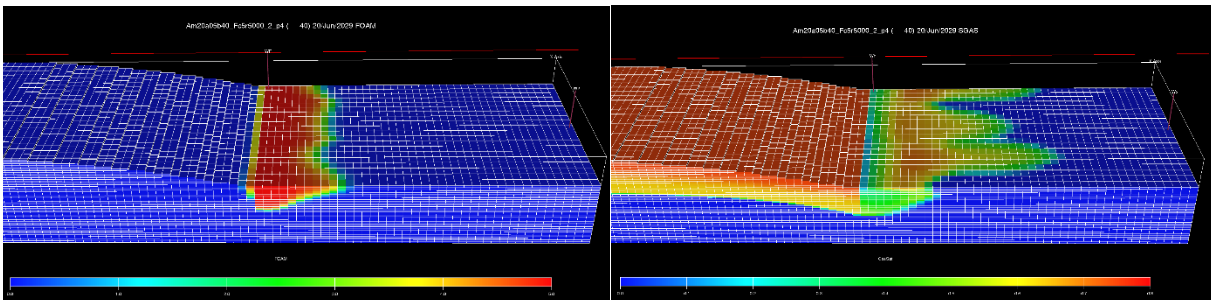


Figure 36. *Surfactant injection at 5,000 rm^3/d for 0.25 year followed by 12 years at 500 rm^3/d, a) foam concentration at the end of 19.75 years, b) CO_2 concentration at the end of 19.75 years.*

5. In the final optimization trial the initial 0.25 year injection period was maintained at 5000 sm^3/d, but during the remainder of the simulation this was reduced further to 500 sm^3/d. The results in Figure 36 show that foam plug is not as deep as in the previous simulation with the result that CO_2 under-run occurs to a significant degree. The final leakage increased to 28% of the Base Case at 5.5% unit effectiveness.

3.3 Remarks on foam injection remediation

Based on the numerical investigations performed, the following conclusions can be drawn on CO_2 leakage mitigation by means of foam:-

- Foam behaviour in porous media is complicated and depends on a large number of parameters. It is challenging to model numerically, in particular at the field scale, even ignoring the heterogeneities occurring in a real reservoir.
- An acceptable model for foam as a plugging agent was created within the Eclipse simulator, although the initial results suggest that the simulations are insensitive to variations in the foam decay half-life parameter.
- Data have been generated to illustrate the effect of a foam plug on CO_2 leakage in a conceptual reservoir model. The effects of surfactant concentration, injection rate and injection duration, have been studied. Data are presented in terms of percentage reduction of leakage and percentage reduction of leakage per million kg of surfactant used (unit effectiveness). The effect of well location and orientation and CO_2 injection rates have been tested to a very limited extent.
- An inverse relationship was found between the leakage reduction and the unit effectiveness (leakage reduction % per million kg surfactant used)
- The greatest reduction in leakage volume achieved was down to 14% of the unimpeded leakage, but this requires a lot of surfactant giving a unit effectiveness of 3.6% reduction per million kg surfactant.
- High surfactant concentration alone is insufficient to create an effective foam plug; sufficient water must be injected to form a large enough plug to prevent by-passing by CO_2.
- A foam plug is not very durable and needs to be maintained by continuous or frequent intermittent surfactant injection.
- The foam plug should form a continuous wall towards the approaching CO_2, wide enough and reaching from the top layer (to prevent over-run) down to a deep enough level to prevent under-run by the accumulating CO_2.
- The injection well configuration has not been investigated thoroughly, but in view of the previous point, the use of several well branches (vertical or horizontal) may give a large enough plug cross-section with less surfactant injection than used in this study. This depends heavily on the actual topography of the leakage area in the reservoir.

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APPENDIX 1 – DETAIL OF FOAM MITIGATION SIMULATIONS

	Case	Description	Results	surf conc kg/sm3	surf inj duration days (1)	w+surf inj rate (1) rm3/d=sm3/d	surf inj duration days (2)	w+surf inj rate (2) rm3/d=sm3/d	CO2 inj rate sm3/d	CPU sec	CO2 flow into FIP2 (sm3) - *from last report in -PRT files*	leakage % of base case (z=18)	leakage % of base case (z=17)	Surfactant used (kg)	%reduction / 10^6 kg surfactant
	Am20a05b40_NF2_2	As _NF2 but with surf conc in WFOAM set to 0. Water injection for 90 days. (Horiz injector, z=18.)	This shows that _NF, _NF2 & _NF3 still carried the action of surfactant., i.e. FOAMDCYW was not sufficient to stop this. The effect of surfactant in _NF2 etc was significant. **<u>This is now used as the new baseline.</u>**	**0**	**90**	**1000**			**4000**	**396**	**2,112,024,395**		100%	0	0.0%
	Am20a05b40_NF2_2nw	As _NF2_2 but WI cut out. (Well WF horiz)	Relatively little effect cf NF2_2. Shows that the effect of WI is minimal (at the present rate) cf the effect of surfactant.	0	0	1000			4000	391	2,120,916,401		100%	0	0.0%
	Am20a05b40_Fc5v (previously Am20a05b40_Fc5)	Re-introduce surfactant concentration (0.005% wt) but with injection well G1 now <u>vertical</u>, perforated at (110, 10, 17). Surfactant injection for 90 days only.	Higher leakage (flow into region2) due to vertical well unstead of horizontal. Same water inj rate plus surfactant. Will revert to horiz well plus water for future sensitivities. Injection must be in the top layer (17) otherwise the CO2 bypasses it above.	5	90	1000			4000	391	2,065,657,232		98%	450,000	4.9%
Surf. Concentration	Am20a05b40_Fc5h	As _NF-2_2 with surfactant restored at 0.5%wt. Decay half-life = 40 days. (Well WF horiz) z=18	Difference compared with NF2_2 shows effect of surfactant. Floviz FOAM shows quite a small plug and under-run by the CO2 - check.	**5**	90	1000			4000	423	1,974,050,548	93%		450,000	14.5%
	Am20a05b40_Fc5h_2	As Am20a05b40_Fc5h but with injector WF raised to z=17.	**Reference case for variations in parameters.**	**5**	90	1000			4000	403	1,928,714,422		91%	450,000	19.3%
	Am20a05b40_Fc50	As Am20a05b40_Fc5h but with surf conc increased to 5% wt. Half-life restored to 40 days.(Well WF horiz)	Significant reduction in leakage.	**50**	90	1000			4000	500	1,495,197,858	71%		4,500,000	6.5%
	Am20a05b40_Fc50_2	As Am20a05b40_Fc50 but with injector WF raised to z=17.	Higher leakage than with injection in z=18.	**50**	90	1000			4000	404	1,554,379,354		74%	4,500,000	5.9%
	Am20a05b40_Fc100	As Am20a05b40_Fc50 but with surf conc increased to 10% wt.	Further reduction.	**100**	90	1000			4000	487	1,381,969,883	65%		9,000,000	3.8%
	Am20a05b40_Fc100_2	As Am20a05b40_Fc100 but with injector WF raised to z=17.	Higher leakage than with injection in z=18. The CO2 appears to be diluted and spread downstream, and covers little depth. The result is that the CO2 undercuts the foam.	**100**	90	1000			4000	396	1,511,842,082		72%	9,000,000	3.2%
Surf.Injn. duration	Am20a05b40_Fc5d360	As -Fc5h but surf injection duration increased to 1 year		**5**	**360**	1000			4000	449	1,778,151,545	84%		1,800,000	8.8%
	Am20a05b40_Fc5d360_2	As Am20a05b40_Fc5d360 but with injector WF raised to z=17.	Improved with raised injector	**5**	**360**	1000			4000	478	1,573,769,892		75%	1,800,000	14.2%
	Am20a05b40_Fc5d1800	As -Fc5d360 but surf injection duration increased to 5 years		**5**	**1800**	1000			4000	670	1,449,650,764	69%		9,000,000	3.5%
	Am20a05b40_Fc5d1800_2	As Am20a05b40_Fc5d1800 but with injector WF raised to z=17.	Large improvement with raised injector	**5**	**1800**	1000			4000	423	906,244,331		43%	9,000,000	6.3%
	Am20a05b40_Fc5d4500	As -Fc5d360 but surf injection duration increased to 12.50 years (end of run)	FOAM variable in Floviz shows significant extent of foam at the end of the simulation period. This appears to present a deep enough barrier to the CO2 in Region 1, while continued penetration of injected CO2 suggests significant remaining permeability for CO2 in the plug. Note that the surfactant sinks nicely.	**5**	**4500**	1000			4000	719	899,388,811	43%		22,500,000	2.6%
	Am20a05b40_Fc5d4500_2	As Am20a05b40_Fc5d4500 but with injector WF raised to z=17.	Very large improvement with raised injector. This gives the lowest leakage of all cases tested, joint with _Fc5r5000_2_p3	**5**	**4500**	1000			4000	561	292,329,343		14%	22,500,000	3.8%

	Case	Description	Results	surf conc kg/sm3	surf inj duration days (1)	w+surf inj rate (1) rm3/d=sm3/d	surf inj duration days (2)	w+surf inj rate (2) rm3/d=sm3/d	CO2 inj rate sm3/d	CPU sec	CO2 flow into FIP2 (sm3) - *from last report in -PRT files*	leakage % of base case (z=18)	leakage % of base case (z=17)	Surfactant used (kg)	%reduction / 10^6 kg surfactant
Surf + water injn rate	Am20a05b40_Fc5r5000	As -Fc5h with water+surfactant injection rate increased from 1000 to 5000 rm3/d. 90 days injn at 0.5% conc.	Quite a good reduction for a short injection period. However the foam plug is small and dilutes quickly.	5	90	**5000**			4000	554	1,550,049,489	73%		2,250,000	11.8%
	Am20a05b40_Fc5r5000_2	As Am20a05b40_Fc5r5000 but with injector WF raised to z=17.	insignificant reduction	5	90	**5000**			4000	485	1,538,038,246		73%	2,250,000	12.1%
	Am20a05b40_Fc5r10000	As -Fc5r5000 with water+surfactant injection rate increased from 5000 to 10,000 rm3/d. 90 days injn at 0.5% conc.		5	90	**10000**			4000	597	1,278,175,392	61%		4,500,000	8.8%
	Am20a05b40_Fc5r10000_2	As Am20a05b40_Fc5r10000 but with injector WF raised to z=17.	insignificant reduction	5	90	**10000**			4000	579 (9min)	1,270,779,352		60%	4,500,000	8.9%
CO2 injn rate	Am20a05b40_Fc5i6000	As Am20a05b40_Fc5h with CO2 injection rate increased from 4000 rm3/d (1Mt/d?) to 6000 sm3/d. Horizontal injector at z=18.		5	90	1000			**6000**	773	4,165,065,766	197%		450,000	-216.0%
	Am20a05b40_Fc5i6000_2	As Am20a05b40_Fc5i6000 but with injector WF raised to z=17.	no effect	5	90	1000			**6000**	750	4,172,986,826		198%	450,000	-216.8%
	Am20a05b40_Fc5i8000	As Am20a05b40_Fc5i6000 but with CO2 injection rate increased to 8000 rm3/d	3x leakage rate for 2x injection rate!	5	90	1000			**8000**	1052	6,544,759,925	310%		450,000	-466.4%
	Am20a05b40_Fc5i8000_2	As Am20a05b40_Fc5i8000 but with injector WF raised to z=17.	No effect	5	90	1000			**8000**	1054	6,557,079,355		310%	450,000	-467.7%
Leakage minimisation	Am20a05b40_Fc5h_2 as above	5 kg/sm3 surf conc, 1000 rm3/d surf+water injection for 90 days	A very small foam plug is formed, which largely remains until the end of the simulation. However the CO2 manages to under-ride and perforate the plug relatively quickly.	5	90	1,000	90		4,000		1,928,714,422		91%	450,000	19%
	Am20a05b40_Fc5r5000_2 as above	Low conc is OK, inject more early on to establish a bigger plug. 5 kg/sm3 surf conc, 5000 rm3/d surf+water injection for 90 days	Stops significant break-through for 4 years until 2021, by which time the foam has degraded and spread out somewhat. Try a repeat injection in August 2020.	5	90	5,000	90		4,000		1,538,038,246		73%	2,250,000	12%
	Am20a05b40_Fc5r5000_2_p2	Now extend the duration - try a second batch later instead of continuous injection. As -Fc5r5000_2 above, with a second 90 day 5000 rm3/d injection period 3 years later, beginning in May 2020 (occurs in timestep 23)	The refill is achieved by report #23 (Aug 2023) and the plug remains largely intact for the remainder of the simulation. However although the CO2 flow is restrained it is not stopped and a significant leakage occurs by the end of the simulation. This is due to under-run as well as remaining permeability.	5	180	5,000	180	5,000	4,000	586	1,183,789,368		56%	4,500,000	9.8%
	Am20a05b40_Fc5r5000_2_p3	Try an initial 5000 rm3/d injection for 90 days (as -Fc5r5000_2) followed by continuous injection at 1000 sm3/d. More long-lasting but modest maintenance of the plug.	This gives a very powerful block to CO2 migration, limiting it to the region of the plug right to the end of the simulation. However the resulting foam plug is very long and might be reduced in size. Nearly the lowest leakage total obtained.	5	90	5000	4320	1000	4,000	463	295,096,314		14%	23,850,000	3.6%
	Am20a05b40_Fc5r5000_2_p4	As -Fc5r5000_2_p3 but with second stage surfactant injection reduced to 500 rm3/d. Try to economise on the maintenance of the plug.	Good blocking until 2025, when the well of CO2 upstream begins to under-run the plug and begins to by-pass it significantly. The critical aspect seems to be maintaining a deep enough plug, plus enough concentration within the plug to restrict gas transmissibility. Double so much leakage as in r500_2_p3	5	90	5000	4320	500	0	433	588,948,057		28%	13,050,000	5.5%