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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 programme. 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 effectiveness of polymer-gel solutions in remediation of CO_2 leakage from storage reservoirs. The report is presented in two distinct Sections. The first Section presents work carried out to assess the effectiveness of polymer-gel injection by converting the CO_2 injection well or newly drilled wells for use as polymer-gel injectors. In this respect, the report addresses both CO_2 flow diversion within the reservoir and the remediation of leakage through faults and/or fracture zones in the caprock using polymer-gel injection in a shallower, high permeability formation above the caprock. In this Section, the first part provides the results of numerical simulations of polymer-gel injection process using a chemical flooding simulation software UTCHEM in order to investigate the effect of various reactant parameters, such as polymer and crosslinker concentration, on the

gelation process and its area of influence. The second and third parts of the first Section of the report provide the results of numerical simulations of polymer-gel injection for flow diversion of the CO_2 plume in the reservoir and the remediation of leakage through fractured caprock using Schlumberger's Eclipse (E300) simulator. Here, it was assumed that leakage through a sub-seismic fault was detected in the shallow aquifer during CO_2 injection. A realistic reservoir model developed by IMPERIAL was used to study a number of leakage and remediation scenarios. The results obtained from laboratory investigations of polymer-gel characterisation and core flooding experiments that were conducted in the MiReCOL project were used to define a range of permeabilities for the polymer-gel treatments modelled. Depending of proximity of injection well to target area and type of polymer used, the amount of polymer solution, area of influence, and cost of treatments were estimated for the remediation cases considered.

The second Section of the report presents research carried out to assess the potential for using hydraulically created fractures to deliver a sealant gel (or foam) to a leaky fault or a leaky zone to create a barrier. Modelling work performed by TNO used the P18 gas field to demonstrate the technology in a real field site. This section presents a brief summary of the geology of the P18 field, the leakage scenarios that have been analysed, and the methods that were used to evaluate the mitigation and remediation of CO_2 leakage.

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SECTION I

POLYMER-GELL INJECTION FOR LEAKAGE REMEDIATION

1 INTRODUCTION

The effectiveness of low permeability polymer-gel barriers in diverting the CO_2 plume from a sub-seismic fault in the reservoir and caprock was previously investigated by considering different layouts of the barrier in the storage reservoir. In a previous report, an assessment of the effectiveness of local permeability reduction in the reservoir caused by the polymer-gel barrier was made by drawing a comparison between the estimated amounts of CO_2 that leaked into shallow aquifer before and after the placement of the barrier.

In this report, the results of numerical simulations of polymer-gel injection into the targeted zones of both the reservoir and shallow high permeability formations overlying the caprock for the flow diversion of the plume and the consequent remediation of leakage through the fractured caprock are presented as a follow up. In both the cases, the area of influence of polymer-gel remediation and the volume of the polymer-gel required for effective treatment have also been estimated for a number of cases considered.

A chemical flooding reservoir simulation software UTCHEM was used to simulate polymer injection and its subsequent gelation process in a saline aquifer model. Parameters such as polymer concentration, polymer-to-crosslinker ratio and its influence on the gelation process, and the area of influence were investigated. In addition, the effect of delaying agent on the gelation process and area of influence was investigated by considering a range of kinetic rate constants for the reaction between the polymer and crosslinker.

Furthermore, using Schlumberger's Eclipse 300 (E300) software, the injection of polymer-gel solution was simulated and the area of influence and volume of polymer-gel needed were estimated for each case. The effect of the delaying agent on the area of influence was considered by using a range of polymer viscosity values. Based on the proximity of the polymer injection well to target zone and viscosity of the solution, a range of polymer treatment cases were defined. The cost of polymer-gel treatment has also been estimated for the scenarios considered.

1.1 Polymer-gel remediation as a 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 extremely 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).

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).

2 NUMERICAL MODELLING OF POLMER INJECTION AND ITS GELATION PROCESS

The UTCHEM software was used to simulate polymer injection and its subsequent gelation process in a saline aquifer model.

The model represents a simplified homogenous reservoir at approximately 1,600m depth and dipping at 22°. The grid spans an area of 750m×750m, and consists of a single layer with a resolution of 25m and a thickness of 15m. The initial pressure distribution of the formation is assumed to be hydrostatic, with an average of 174bar, as illustrated in Figure 1. The fracture pressure of the formation was assumed to be 1.5 times the initial hydrostatic pressure.

The petrophysical properties of the saline aquifer, such as porosity, permeability, salinity and temperature were assumed to be uniform in order to study the gelation process (Table 1). These values are based on previous studies that were reported for the North Sea-type reservoir conditions (Durucan et al., 2016).

Table 1 Static properties of the saline aquifer considered for the model setup.

Property	Value
Porosity [%]	20
Horizontal permeability [mD]*	3,000
Salinity [%]	12
Temperature [°C]	92

*Vertical permeability = 0.1 × Horizontal permeability

The polymer injection well is located at the centre of the model. As part of the injection strategy, the period of injection and observation (shut-in) were considered to be fixed as 10 and 40 days respectively.

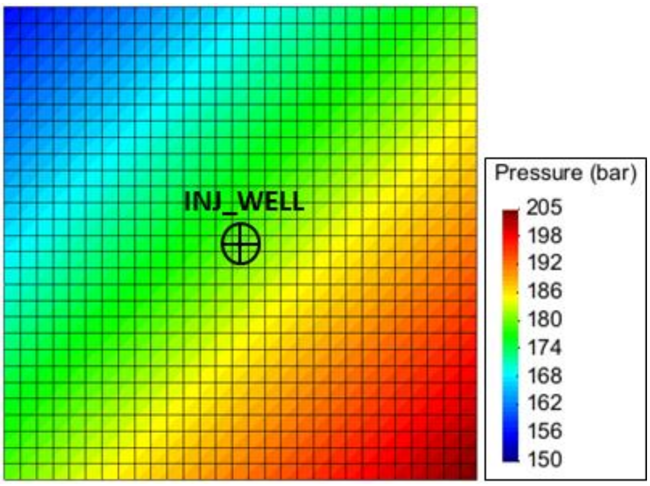


Figure 1 The numerical reservoir model with a resolution of 25m×25m grid blocks.

2.1 Modelling the gelation process

The gelation process for the polyacrylamide-based polymers and chromium crosslinker was investigated by simulating the injection of a solution of 300ppm polymer and 50ppm crosslinker into the porous medium. Figure 2 shows the area influenced by the polymer-gel plume and its concentration at different time steps.

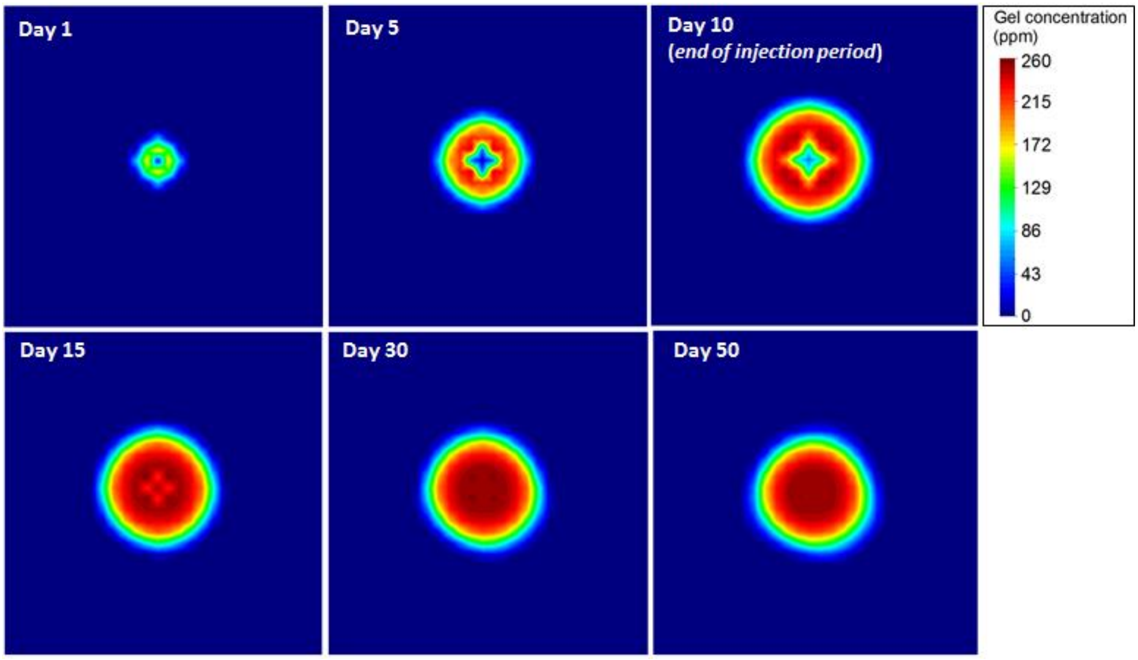


Figure 2 Gel concentration and the area of influence at different time steps.

A lower gel concentration is observed at the centre of the plume. This is owing to the fact that the polymer solution is a non-Newtonian fluid and its viscosity is affected by the shear rate induced at the location of injection. Figure 3 presents changes in gel concentration around the injection well with time. After 10 days, when the injection was stopped, the effect of shear rate disappears and hence the gel concentration in the near-well region attains its maximum value of approximately 260ppm.

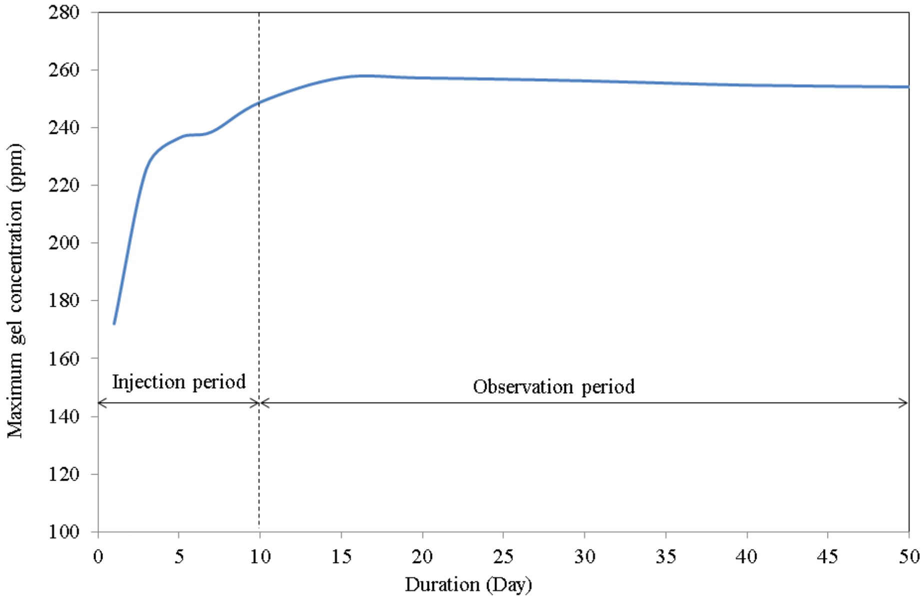


Figure 3 The variation of gel concentration with time.

2.2 The effect of initial formation permeability

The effect of the initial formation permeability on polymer distribution inside the reservoir was investigated by performing simulations for permeability values ranging from 1,000mD to 3,000mD in the saline aquifer model. A solution with concentrations of 300ppm polymer and 50ppm crosslinker was injected into the formation. The results of the simulation runs for the final time step (day 50) are presented in Figure 4 for each case.

The results show that, for the given reservoir conditions and polymer solution, the area of influence increases as the reservoir permeability increases (Figure 4). This is expected and is also partly attributed to the fact that at constant injection rates, lower permeability of the formation leads to rapid bottomhole pressure increase, reaching the maximum allowable pressure limit in order to avoid induced fractures in the system.

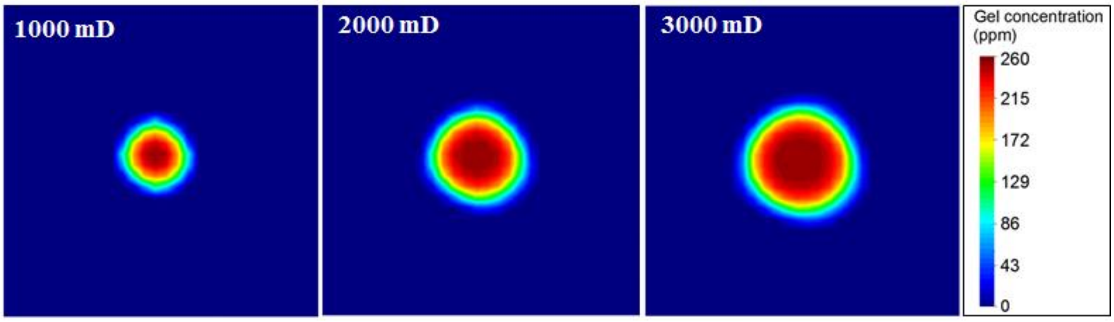


Figure 4 Effect of initial formation permeability on polymer-gel treatment in terms of the area of influence (300ppm polymer and 50ppm crosslinker solution injected).

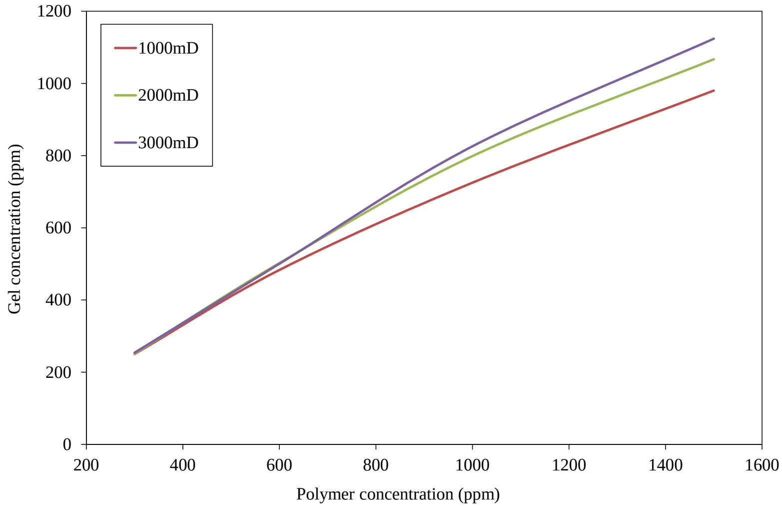
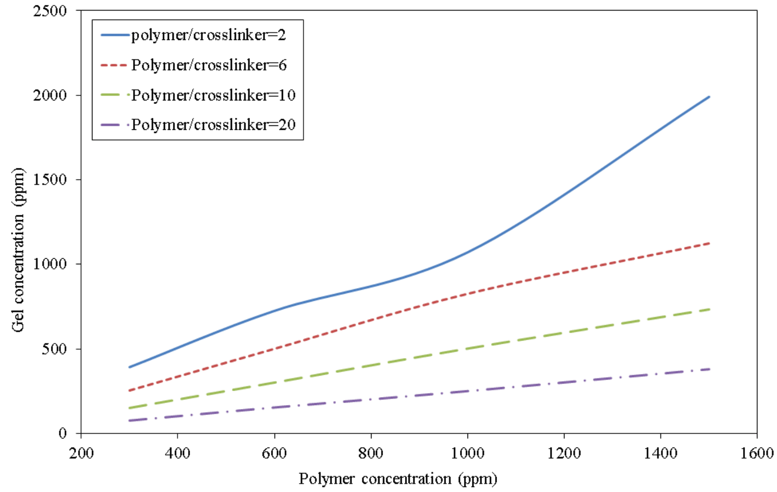


Figure 5 Gel concentration achieved at different polymer concentrations and reservoir permeabilities.

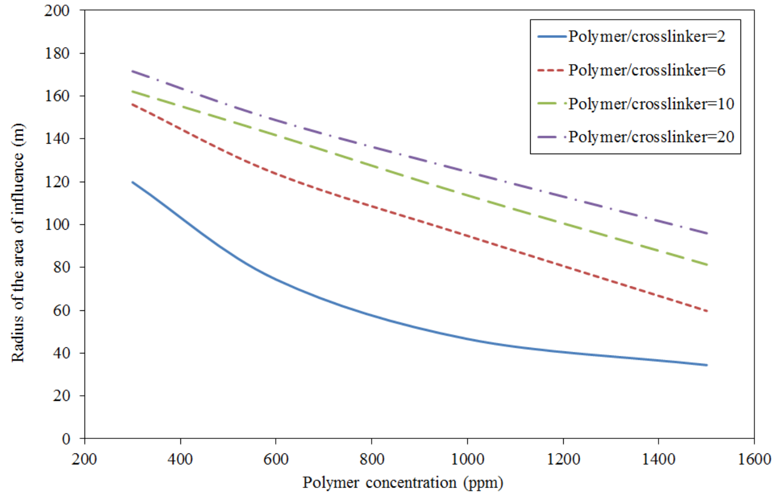
Figure 5 presents the changes in gel concentrations with time when the formation permeability is varied. For simulation runs with lower concentrations of the polymer, the permeability of the formation does not affect the gelation process. For higher polymer concentrations, however, the gel concentration reduces with decreased permeability. This is due to the development of higher shear rates during the injection of the polymer solution, which in turn reduces the gel viscosity.

2.3 Effect of polymer and crosslinker concentrations

In order to assess the effect of polymer-to-crosslinker ratio on the effectiveness of polymer-gel treatments a number of simulations were performed for a range of polymer and crosslinker concentrations. The key output parameters that have been considered were: i) the gel strength and ii) the area of influence. The gel strength is characterised by the concentration of the produced gel; in general, the higher the concentration of produced gel, the stronger and more stable the gel is. The area of influence is also an important factor especially for cases where far-field gel treatments are required. To evaluate the polymer-gel treatment process, simulations have been run with concentrations at 300ppm, 600ppm, 1,000ppm and 1,500ppm. For each case, the polymer to crosslinker ratio was varied between 2 and 20. The results of simulations are presented in Figures 6a and 6b.



(a)



(b)

Figure 6. Effect of polymer and crosslinker concentrations on: a) gel concentration; and b) the area of influence.

The results of the simulations show that the concentration of the produced gel increases with increased polymer and crosslinker concentrations. In other words, at lower polymer to crosslinker ratios a relatively higher gel concentration is achieved, and therefore a stronger gel can be expected (Figure 6a). On the other hand, the area of influence increases with a decrease in crosslinker concentrations for a given polymer concentration (Figure 6b). This is mainly to the effect of decreased viscosity and slower gelation at lower crosslinker concentrations.

2.4 The effect of pH

The effect of pH on the gelation process and the area of influence was investigated by varying the concentration of H^+ in the range of 0 to 6.3×10^{-5} meq/ml. The initial concentration of H^+ in the formation pore fluid is estimated by the simulation software as 1.26×10^{-8} meq/ml. A solution of 300ppm polymer and 50ppm crosslinker was injected for 10 days, followed by 40 days of observation. The results of polymer gel concentration at various H^+ concentrations are presented in Figures 7a-c.

In the first case (Figure 7a), only polymer and crosslinker were included in the injection stream, therefore the pH of the injected solution is expected to be slightly higher than the pH of the surrounding formation fluid. In the second case (Figure 7b), the concentration of H^+ in the injection stream was increased to that of the concentration in the formation fluid. In the third case (Figure 7c), the H^+ concentration in the injection stream was further increased to 6.3×10^{-5} meq/ml and therefore the pH of the injected solution was lower than the pH of the formation fluid.

In the simulation software, the concentration of H^+ is a controlling parameter on the kinetics of the gelation process, i.e. the higher the concentration of H^+, the slower the crosslinking process. As a result of delayed crosslinking, polymer viscosity does not increase and therefore polymer slug migrates to the far-field region of the reservoir formation before it gels (Figure 7c).

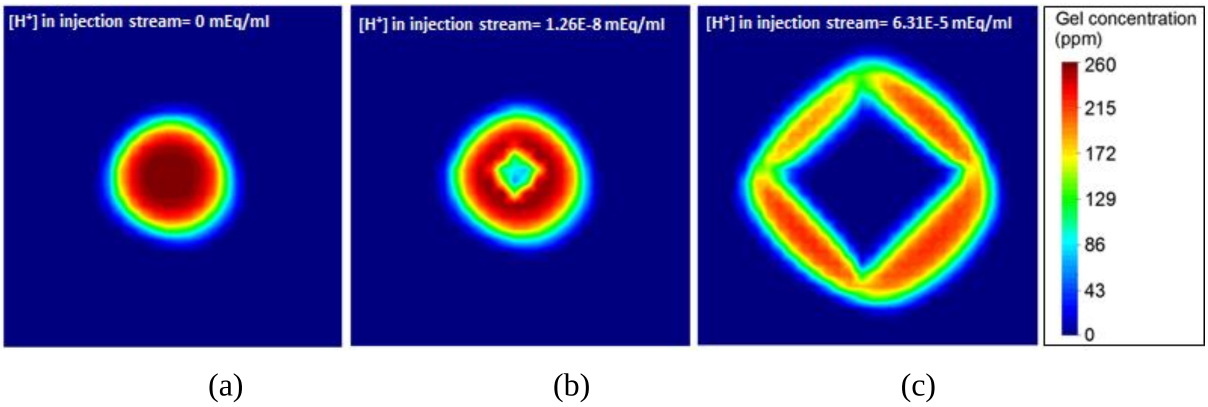


Figure 7 Effect of H^+ concentration on gelation process and the area of influence.

2.5 Effect of gelation kinetics

The kinetic rate constant used for the reactions between polymer and crosslinker in the model defines the viscosity and mobility of the gel, which can be considered as the effect of delaying agent on the gelation process. The reaction rate can also be controlled by adding delaying/accelerating agents to the solution. In particular, the reaction kinetics is described by the following equations (Lockhart, 1992):

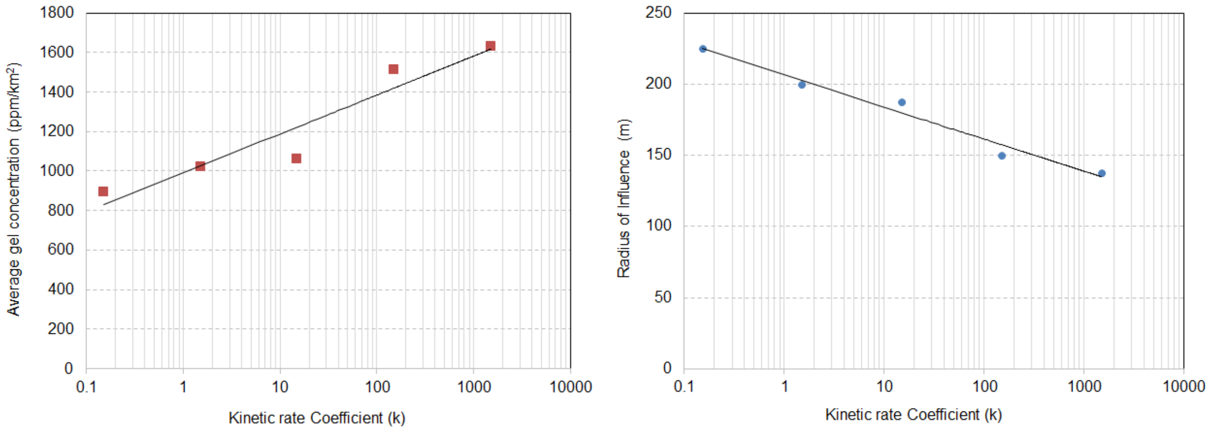
$$[\mathrm{polymer}] + \mathrm{n}[\mathrm{Cr(III)}] = [\mathrm{gel}] \tag{1}$$

$$\frac{d[\mathrm{Cr\ (III)}]}{dt} = -k\,\frac{[\mathrm{Cr\ (III)}]^{0.6}[\mathrm{polymer}]^{2.6}}{[\mathrm{H}^+]^{1.0}} \tag{2}$$

$$\frac{d[\mathrm{gel}]}{dt} = -\frac{1}{n}\frac{d[\mathrm{Cr\ (III)}]}{dt} \tag{3}$$

where, k is the reaction rate constant. A sensitivity analysis was carried out by considering a range of rate constants for the crosslinking process. A series of simulations were performed to investigate the effect of delaying/accelerating agents on the gelation process. The results are presented in Figure 8a and 8b.

The results show that the decrease in reaction rate constant, *i.e.* adding delaying agents (see equations (2) and (3)), leads to production of gel at lower concentrations (Figure 8a). . This type of treatment can be useful for far field treatments, where the area of influence of a larger size is required (Figure 8b).



(a) (b)

Figure 8 Effect of gelation rate on: a) gel concentration; and b) the area of influence.

3 NUMERICAL SIMULATION OF CO_2 LEAKAGE REMEDIATION USING POLYMER-GEL INJECTION

This section presents the results of the numerical modelling carried out to investigate the application of polymer-gel solutions for flow diversion of CO_2 plume within the storage reservoir. The objective of this work was: i) to perform simulations of polymer-gel injection with different remediation layouts after CO_2 leakage has been detected, ii) to estimate the area of influence and volume of polymer gel solution required for each remediation case. The results of laboratory investigations on polymer-gel characterisation and core flooding experiments conducted in the MiReCOL project were used to define a range of permeabilities of the polymer-gel barriers.

3.1 Reservoir model description

3.1.1 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 9), 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×20m. The depth of the model ranges between 1,087m and 3,471m.

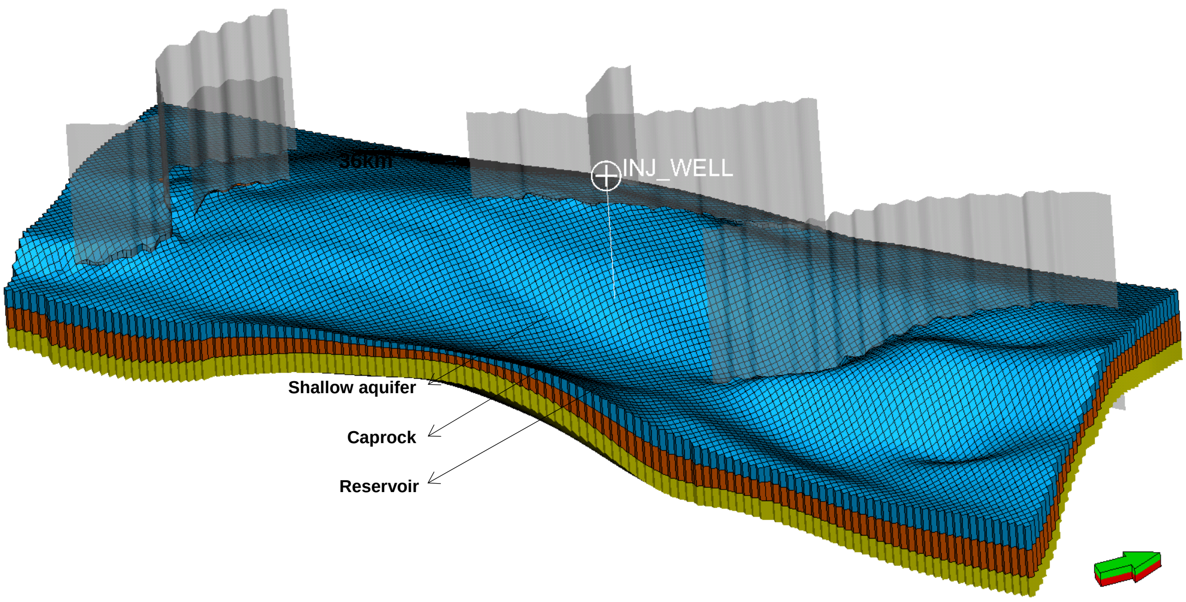


Figure 9 The structural model of the numerical saline aquifer (36km×10km) containing five major faults and three stratigraphic layers: reservoir layer, caprock (seal) layer and shallow aquifer layer.

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 2*. The range of the petrophysical properties used in the static geological model attribution (*Table 3*) 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 10.

Table 2 Channel layout parameters used in the reservoir layer of the geological model.

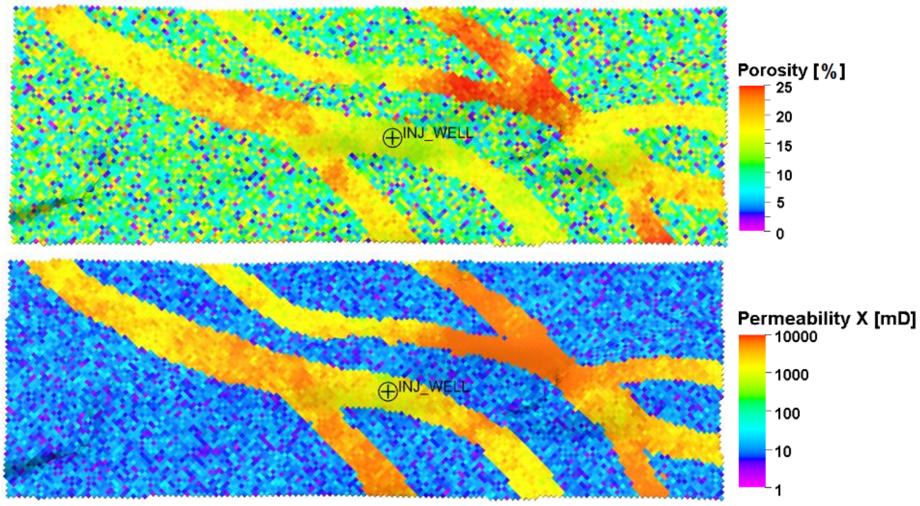
	Min	Mean	Max
Amplitude [m]	400	500	600
Wavelength [m]	14,000	15,000	16,000
Width [m]	1,400	1,500	1,600
Thickness [m]	4	8	12

Table 3 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 10 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).

3.1.2 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.

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 at a rate of 1Mt/year, leakage detection, remediation, and post-remediation CO_2 injection periods.

A sub-seismic fault was introduced in the model at a distance of 1km away from the injection well, located at the flank of the anticline (Figure 11). The fault has a lateral dimension of 1600m×2m, with a uniform vertical permeability of 10^5mD and spanning the reservoir and the caprock thickness (approximately 450m).

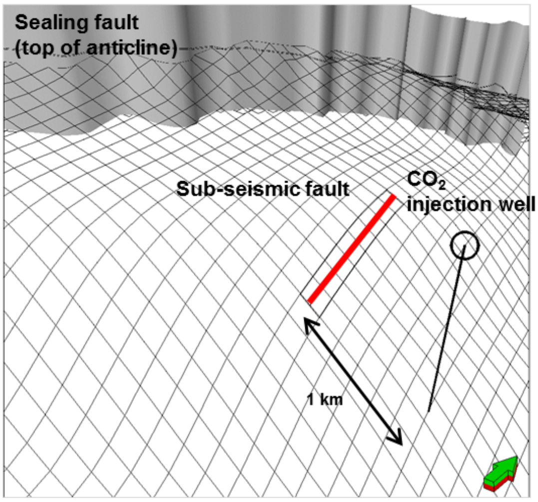


Figure 11 Numerical modelling of field polymer-gel injection.

3.2 Modelling CO_2 leakage remediation using polymer injection in the reservoir

Leakage through the fault was detected inside the shallow aquifer within a few months of injection, assuming 5,000 tonnes of mobile CO_2 as the lower limit for detection (Benson, 2006). CO_2 injection was temporarily terminated until polymer gel treatment in the reservoir was carried out. The remediation was subsequently assessed for the remaining time left during the simulation period of 5 years.

A number of scenarios were considered for the remediation of CO_2 leakage using polymer injection using horizontal well configurations (Figure 12). The scenarios are based on three factors:

- polymer gel viscosity.
- depth of polymer injection in the reservoir.
- proximity of polymer injection to the leaky sub-seismic fault.

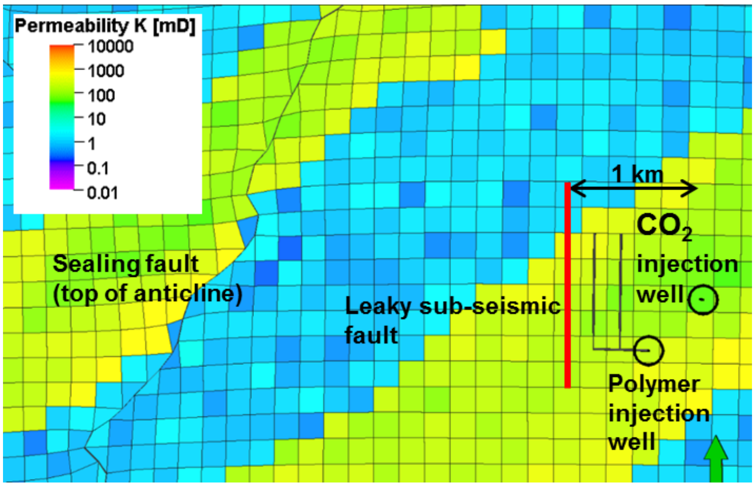


Figure 12 Location of polymer injection well, sub-seismic fault and CO_2 injection well.

3.2.1 Effect of polymer viscosity on its area of influence

The relationship between the polymer concentration and water viscosity multiplier was varied in the Eclipse simulation software as a proxy for the inclusion of delaying agents in the polymer solution (Table 4). Three cases were simulated for a fixed polymer injection period of 20 days and their radii of influence were noted.

Table 4 The relationship between the polymer concentration and water viscosity multiplier as a proxy for the inclusion of delaying agents in the polymer solution.

Polymer concentration (kg/m^3)	**Water viscosity multiplier**		
	High viscosity 0.005Mt polymer injected	Intermediate viscosity 0.08Mt polymer injected	Low viscosity 0.2Mt polymer injected
0	1	1	1
0.1	5	2	2
0.2	7	3	3
0.3	10	5	4
0.4	15	10	5
0.5	20	15	6
0.6	2000	100	10

Figure 13 shows the results of numerical simulations for three cases of polymer-gel injections with high, intermediate and low viscosity ranges, assuming a distance of 800m between the horizontal polymer injection well and the sub-seismic fault.

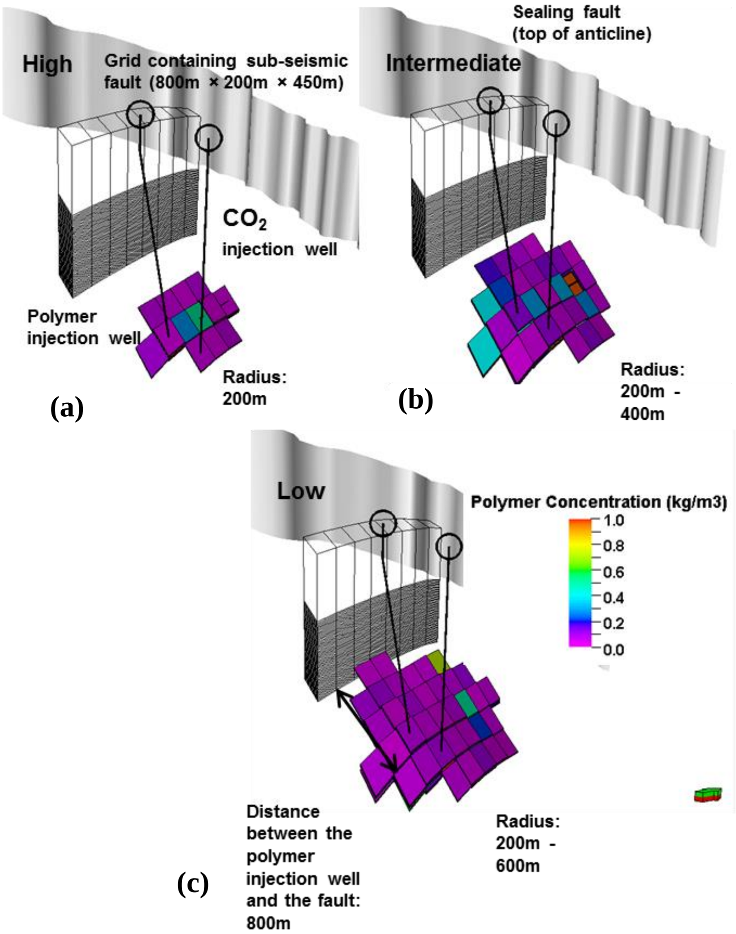
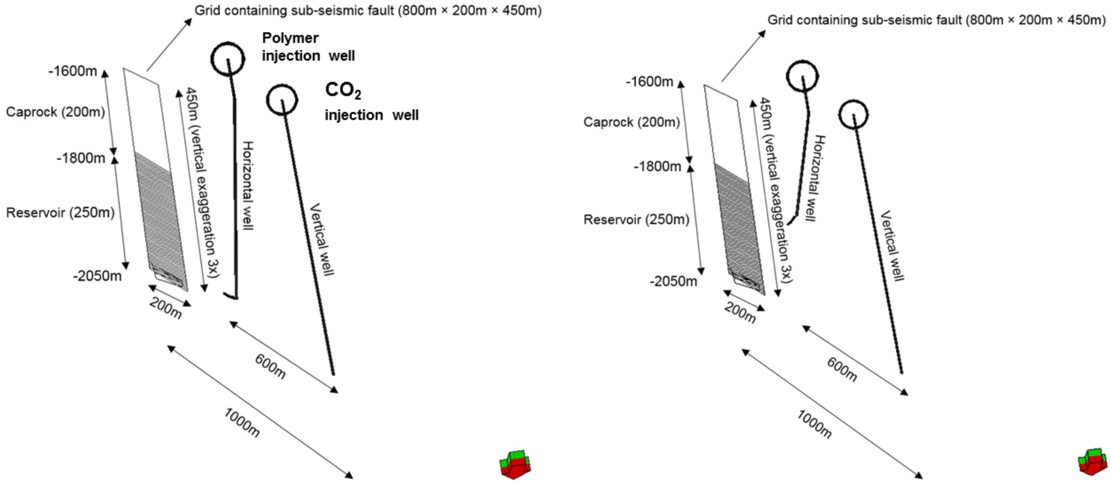


Figure 13 Area of influence after 20 days of polymer-gel injections for a) high, b) intermediate, and c) low viscosity cases.

3.2.2 The proximity of polymer injection well to the sub-seismic leaky fault

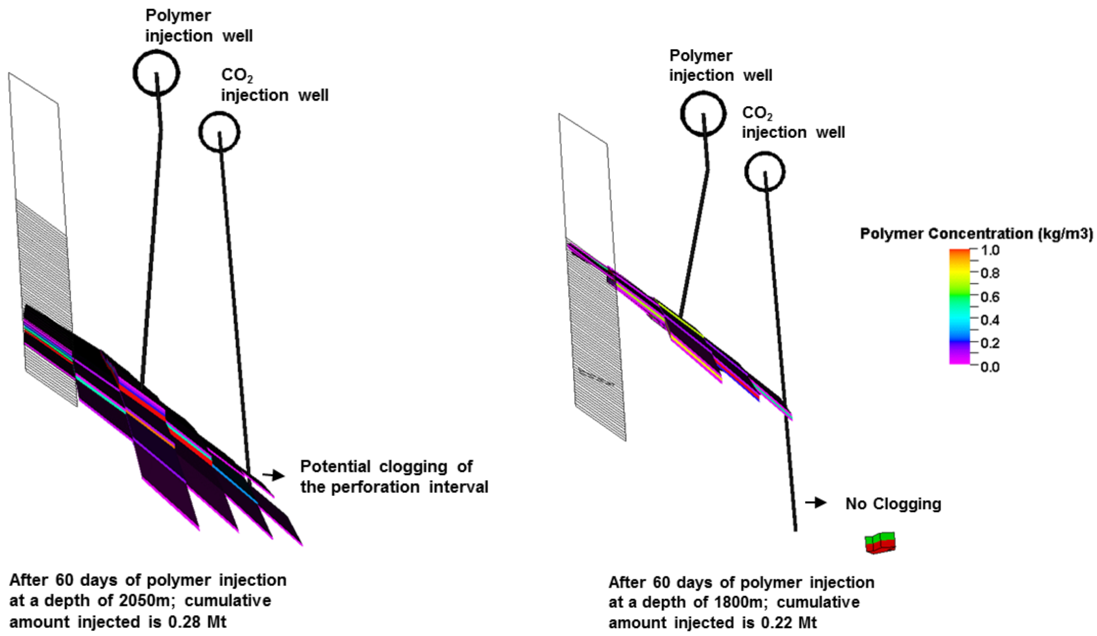
From the previous set of cases, it was observed that a period of injection longer than 20 days may be required to mobilise the polymer towards the fault and potentially help in CO_2 flow diversion. Therefore, the period of injection was further increased to 60 days to allow a larger quantity of polymer in the reservoir. In addition, the distance between the polymer injection well and the fault was reduced to 400m (Figure 14). The depth of injection was varied between: i) at the bottom of the reservoir: 2050m, and ii) at the top of the reservoir: 1800m. For both cases, the intermediate polymer viscosity was implemented.



(a) (b)

Figure 14 Layout of polymer injection well for cases of a) injection at the bottom of reservoir, and b) injection at the top of the reservoir.

The results show that increasing the period of injection, potentially clogs the CO_2 injection well when the polymer is injected at the bottom of the reservoir (Figure 15). Hence, polymer injection just below the caprock using the horizontal well configuration was found to be more suitable. The amount of polymer required is also potentially less when injected at shallower intervals.



(a) (b)

Figure 15 Numerical simulations of polymer injection at the a) bottom of the reservoir, and b) top of the reservoir.

Four cases in which the distance between the polymer injection well and the fault were reduced to200m and 400m from the fault and the results were compared. For all cases, the injection was performed at the top of the reservoir (depth of 1,800m). The effect of varying polymer viscosity was also considered for low and intermediate viscosity ranges (Table 5). The results of simulations are presented in Figure 16.

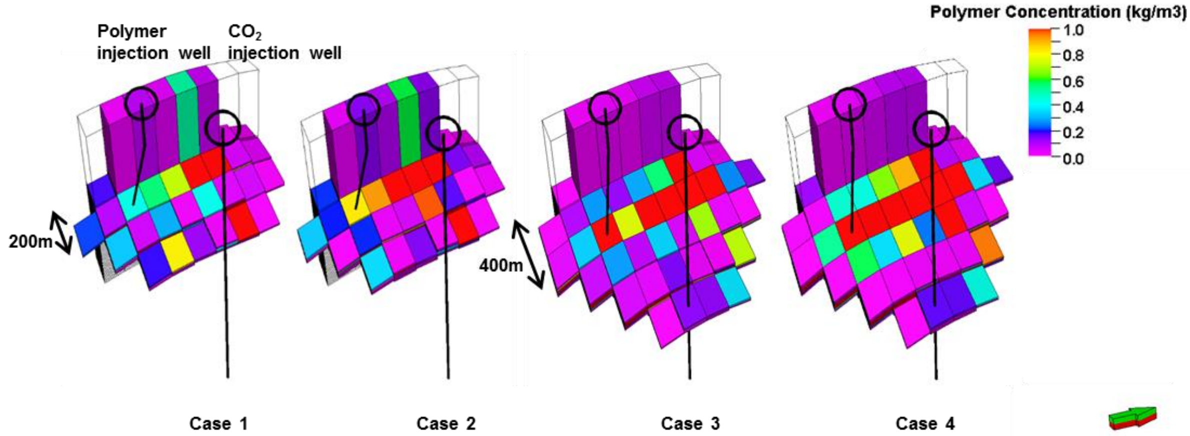


Figure16 The results of numerical simulations for polymer-gel injections at different distances to the leaky fault and with various viscosities.

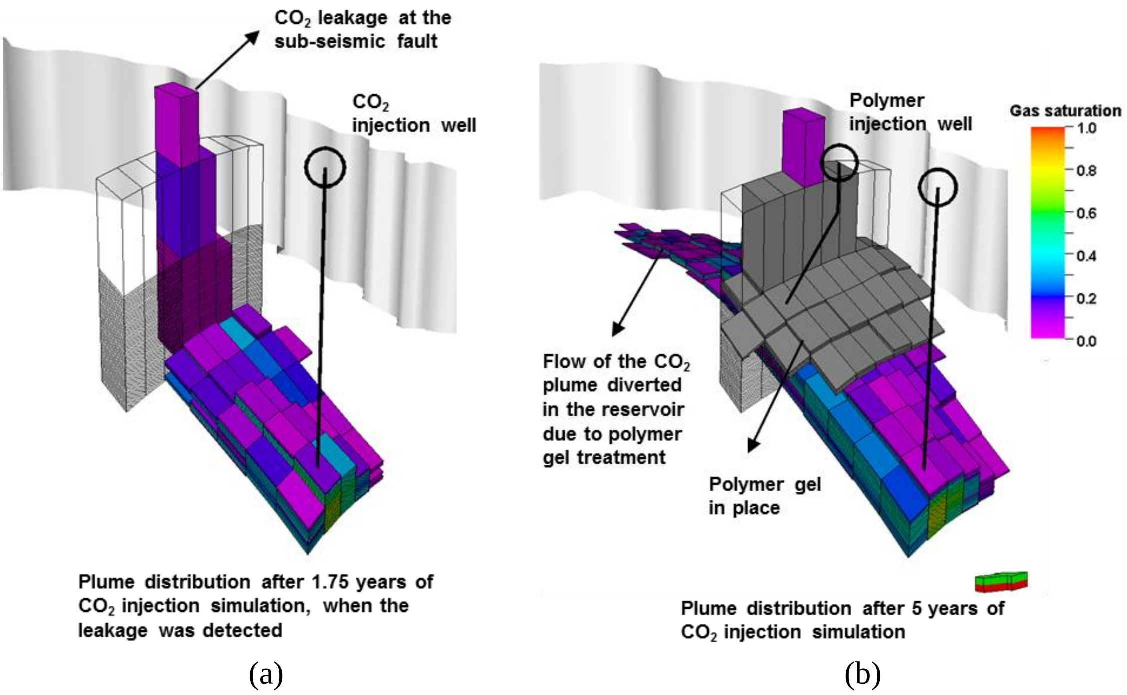


Figure 17 The results of numerical simulations of CO_2 plume distribution: (a) at the time of leakage detection, and (b) after 5 years of post-remediation CO_2 injections.

3.2.3 CO_2 leakage remediation results

To assess leakage remediation, it was assumed that gelation occurs almost immediately after the polymer injection was stopped. For example, considering case 1 in Table 5, after the polymer-gel treatment (assuming a high permeability reduction from 3000mD to 10^{-3}mD, illustrated by the grey region in Figure 17b), CO_2 injection was resumed for the remaining simulation period. Figure 17 shows the results of CO_2 plume distribution after 1.7years when the CO_2 leakage was detected (Figure 17a), and after 5 years of post-remediation CO_2 injections (Figure 17b).

Table 5 Polymer-gel injection cases considered to assess the effect of proximity of the injection well to the leaky fault.

Distance of polymer injection from the fault (m)	Polymer Viscosity	Case #	Amount of polymer injected (Mt)	Time period of injection (days)
200	Low	1	0.29	30
	Intermediate	2	0.34	95
400	Low	3	0.59	60
	Intermediate	4	0.63	185

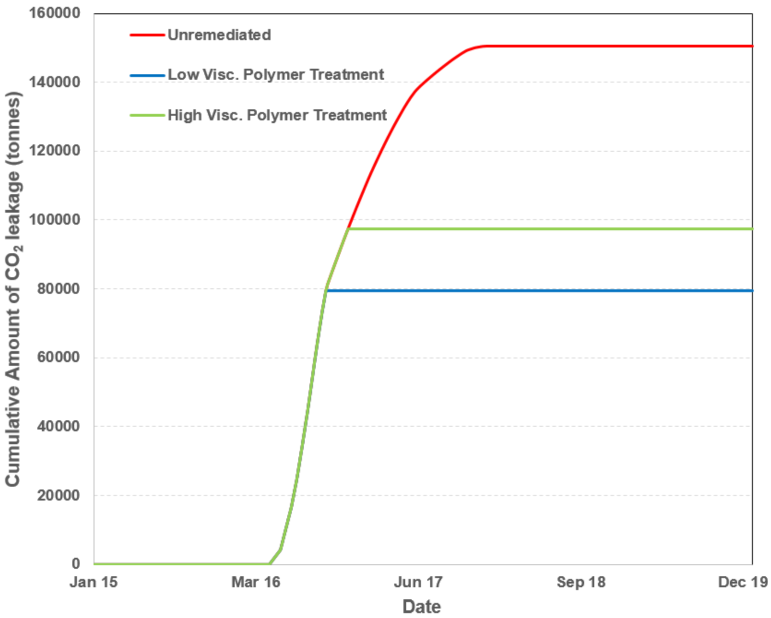


Figure 18 The results of CO_2 leakage remediation for cases of unremediated leakage, low and high viscosity polymer-gel treatments.

Figure 18 shows the comparison between of the amounts of CO_2 leaked into the shallower formations for the unremediated case, as well as the remediated cases using low and intermediate polymer viscosity ranges. For the unremediated case, the total amount of CO_2 loss from the reservoir without polymer treatment after the leakage was detected to be 160kt. For the remediated cases of intermediate and low polymer viscosities, the total amount of CO_2 leakage was estimated to be 80kt and 100kt respectively. The results showed that the polymer-gel solution seals the fault and diverts the CO_2 flow as desired. In the scenarios considered, an appreciable reduction in CO_2 leakage was thus achieved depending on the viscosity of the polymer-gel used and no CO_2 leakage was observed after the implementation of polymer-gel treatments.

3.3 Modelling CO_2 leakage remediation using polymer injection in a shallower aquifer above the caprock

A number of scenarios were considered for the remediation of CO_2 leakage through a subseismic fault in the caprock, using polymer injection via both horizontal and vertical well configurations (Figure 19). The vertical well configuration here was considered to be the CO_2 injection well. The scenarios are based on three factors:

- polymer gel viscosity.
- The layout of polymer injection well (vertical and horizontal configurations) and its proximity to the leaky sub-seismic fault.

CO_2 leakage remediation was assessed during a total simulation period of 5 years.

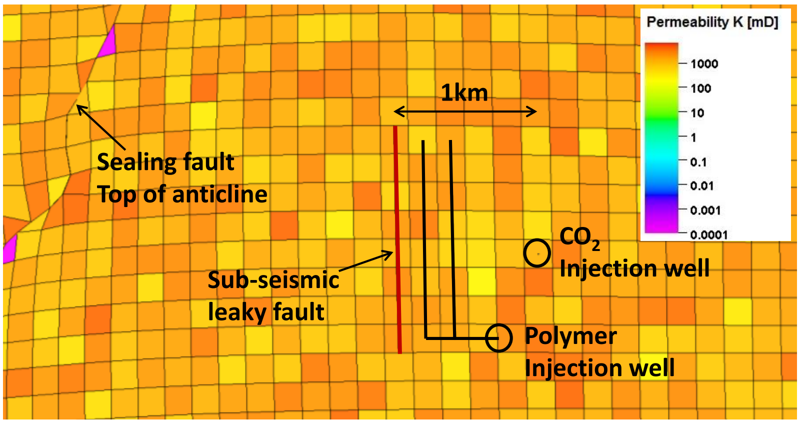
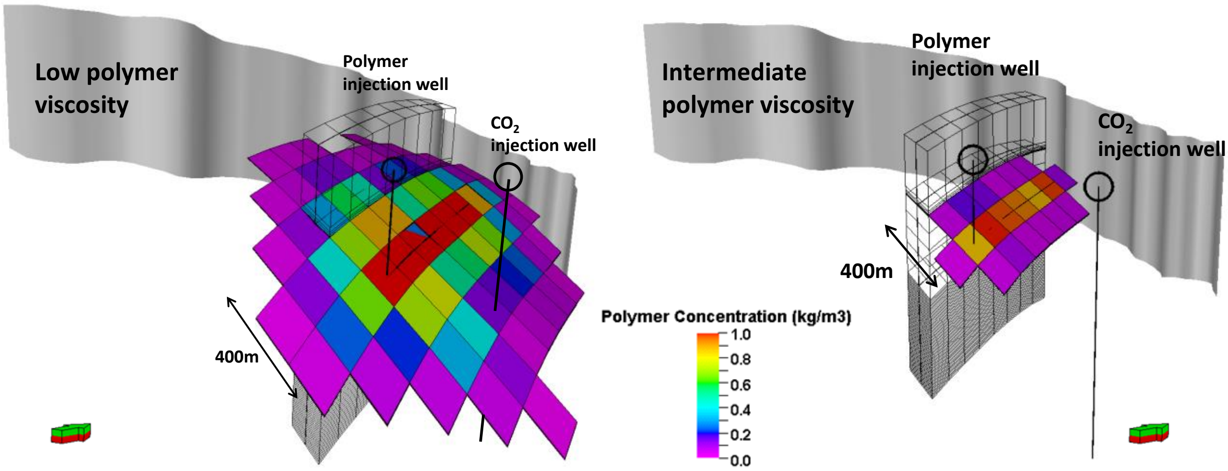


Figure 19 Location of polymer injection well in the shallow aquifer, sub-seismic fault and CO_2 injection well.

3.3.1 Effect of polymer viscosity on its area of influence

The relationship between the polymer concentration and water viscosity multiplier was varied in the Eclipse simulator as a proxy for the inclusion of delaying agents in the polymer solution (see Table 4). Figure 20 shows the results obtained from numerical simulations for two cases of polymer-gel injection into the shallow aquifer formation with intermediate and low viscosity ranges.



(a) (b)

Figure 20 Area of influence after 7 months of polymer-gel injections for a) low, and b) intermediate viscosity cases.

3.3.2 The polymer injection well layout and its proximity to the leaky fault

The time period and amount of polymer required to seal the leaky fault at the top of the caprock was assessed. Four cases were considered in which the injection of polymer-gel at distances of less than 50m, 200m, 400m and 1000m from the fault were compared. For the first three cases, a horizontal injection well was used, whereas for the final case, the CO_2 injection well was used to inject polymer gel solution of low viscosity. In all the cases, the injection was performed at a depth just above the caprock (approximately 1,500m). The results of simulations are presented in Figure 21.

The results show that with increase in distance between polymer injection well and leaky fault, the time period required for effective polymer injection increases significantly. For instance, if polymer injection well located near the leaky faults (with less than 50m distance), the injection duration of 1 month would be sufficient to seal the fault, whereas, for the case of polymer injection location at 400m away from the fault, at least 7 months of polymer injection is to be expected. The amount of polymer required is also higher when injected at longer distances.

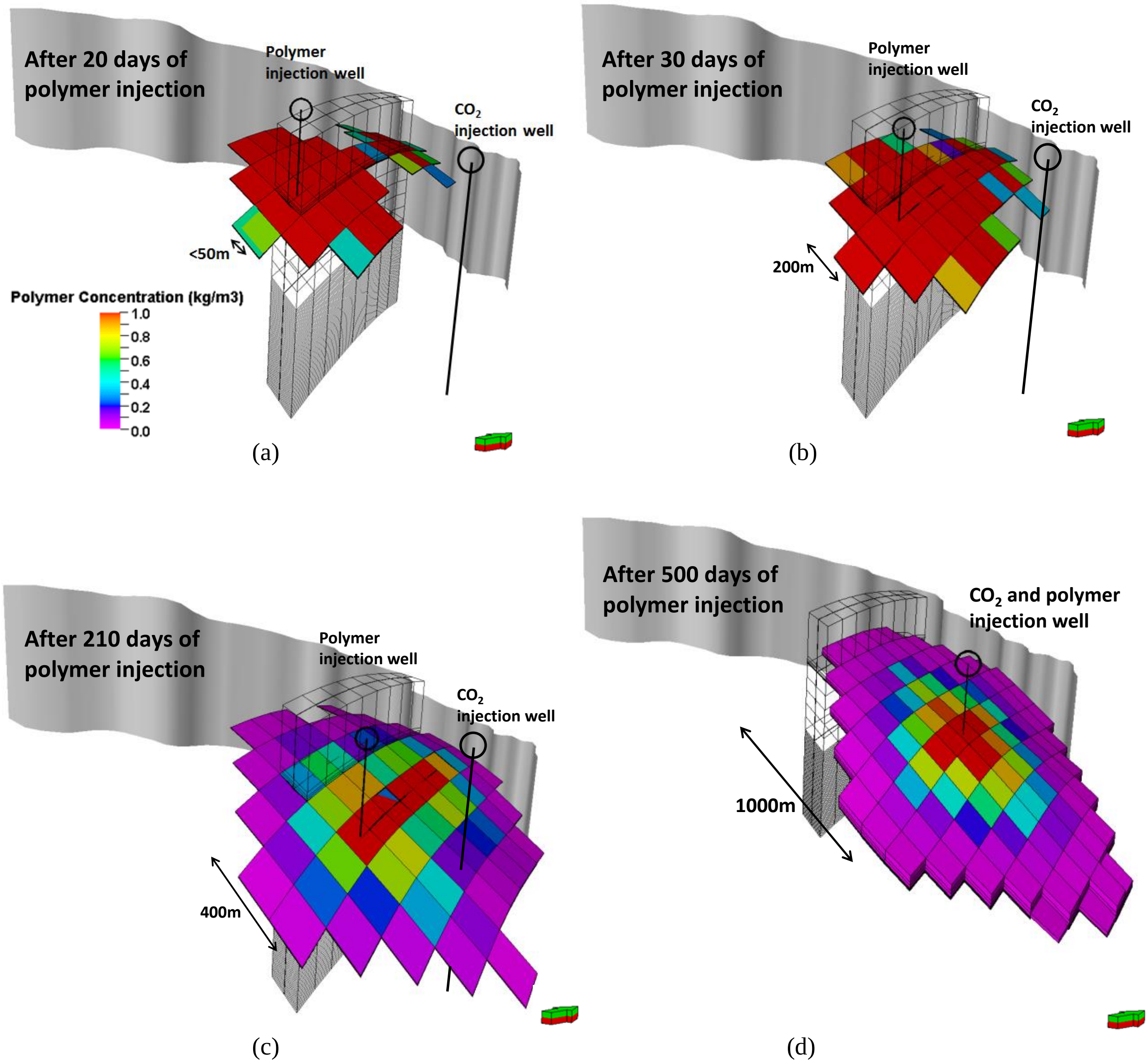
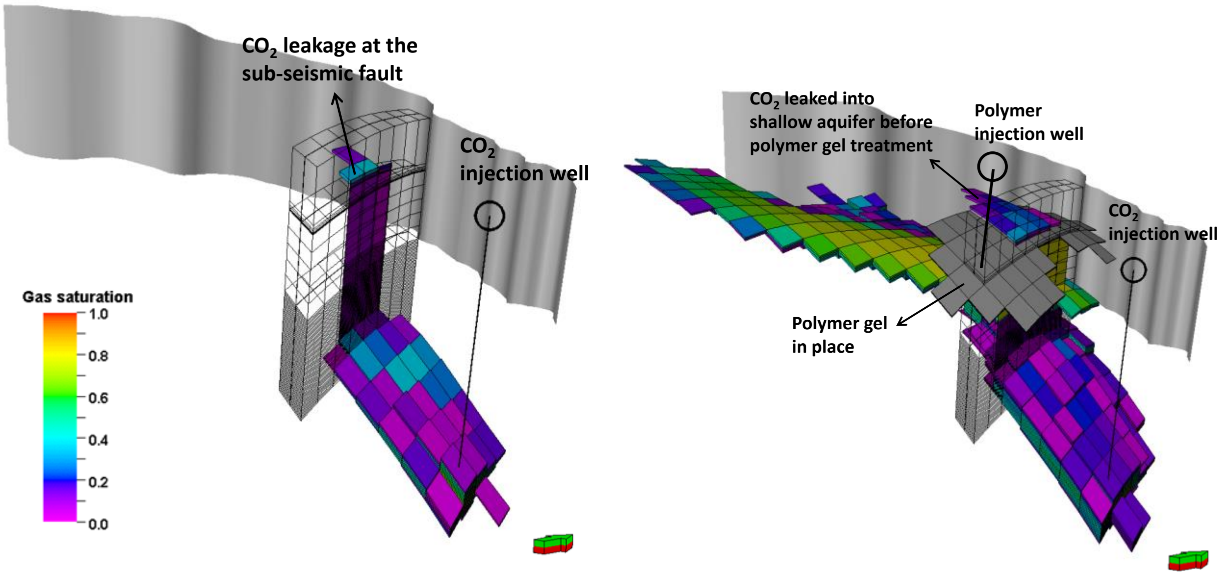


Figure21 The results of numerical simulations for polymer-gel injections at different distances to the leaky fault and with horizontal (a, b and c) and vertical (d) layouts.

3.3.3 CO_2 leakage remediation results

To assess leakage remediation, it was assumed that gelation occurs almost immediately after the polymer injection was stopped. Table 6 presents a summary of polymer remediation cases including the amount of polymer gel and time period of injection required for each case. After polymer-gel treatment (case 5 in Table 6), CO_2 injection was resumed for the remaining simulation period. Figure 22 shows the results of CO_2 plume distribution after 9 months when the leakage was detected (Figure 22a), and after 5 years during the post-remediation period when CO_2 injection was resumed (Figure 22b).



(a) (b)

Figure 22 The results of numerical simulations of CO_2 plume distribution: (a) at the time of leakage detection, and (b) after 5 years of post-remediation CO_2 injections.

Table 6 The amount of polymer-gel and time period required for each polymer-gel remediation cases considered.

Distance of polymer injection from the fault (m)	Polymer Viscosity	Case #	Amount of polymer injected (Mt)	Time period of injection (days)
Less than 50m*	Low	5	0.15	20
200*	Low	6	0.24	30
	Intermediate	7	0.27	360
400*	Low	8	2.0	210
	Intermediate	9	0.4	400
1000**	Low	10	3.2	500

* Polymer-gel is injected using a horizontal well.
** Polymer-gel is injected using the main CO_2 injection well.

Figure 23 shows the results of the amount of CO_2 leakage into shallower formations for the unremediated case as well as the remediated cases of low and intermediate polymer viscosity ranges. Depending on the remediation case, the time period required for polymer-gel treatment (including well drilling and injection) varied between 7 to 29 months. Therefore, the amount of CO_2 leakage after detection and stopping of injection varies slightly. The total amount of CO_2 leaked into the shallow aquifer after the leakage was detected and CO_2 injection stopped was about 60kt. For remediated cases, this value lies between 55kt and 60kt. In these cases however, re-injection of CO_2 into the reservoir did not lead to further CO_2 leakage. In other words, for the scenarios considered no significant CO_2 leakage was observed after the polymer-gel treatments and subsequent re-injection of CO_2. The results showed that the polymer-gel solution seals the fault (assuming a high permeability reduction from 3000mD to 10^{-3}mD, illustrated by the grey region in Figure 22b) and stops further CO_2 leakage into shallow aquifer as desired.

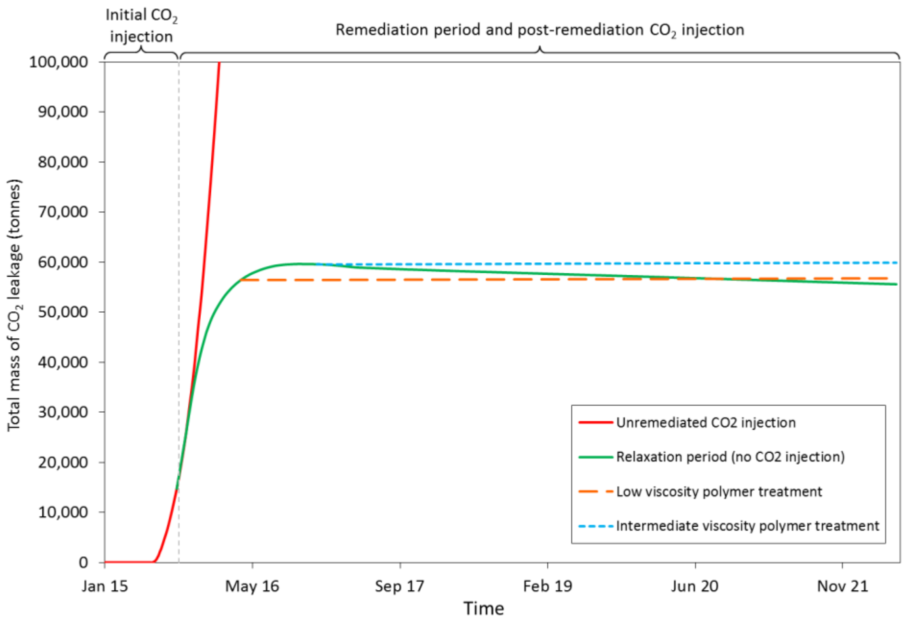


Figure 23 The results of CO_2 leakage remediation for cases of unremediated leakage, low and intermediate viscosity polymer-gel treatments.

4 COST ESTIMATION FOR THE POLYMER-GEL REMEDIATION CASES CONSIDERED

Depending on the type of polymer and crosslinker, different factors should be taken into account, depending on whether the polymer considered is present in emulsion or powder form. For instance, the AN1506 polymer used for the experimental studies in the project conducted at Imperial, its cost in powder form is estimated to be 3.2 €/kg. If a polymer solution with a concentration of 1,000ppm AN1506 is considered, and for every metre cube of solution prepared, 1 kilogram of powder AN1506 is required.

For the crosslinker, the cost of Tyzor 217 (with 5.6% Zr^+ concentration) manufactured by Dorf Ketal, is estimated to be €40 per gallon (equivalent to 10,000 €/m^3). Based on a 50ppm Zr+ concentration in the final solution, for every metre cube of polymer solution to be injected, 0.001 m^3 (1L) of Tyzor 217 is required.

In order to estimate the total cost of polymer-gel remediation, other components should be taken into account, such as the cost of drilling a new well (if required) and its orientation (vertical or horizontal), the cost of polymer solution preparation, transport, and equipment. In addition, depending on the zone (offshore or onshore), the constraints (ATEX area), the type of formation (permeability, salinity, pressure, temperature), and the pumping rates, the cost of remediation can be different. Table 7 provides a summary of the operational parameters assumed for the cost estimation polymer-gel treatment. Tables 8 and 9 present summary of cost estimations for polymer-gel treatment cases considered for flow diversion option and caprock leakage remediation option, respectively.

Table 7 Summary of the operational parameters assumed.

Polymer injection	Offshore cases
Depth of the sea water	120 m
Area for seismic (3D streamer)	16 km^2
Number of seismic surveys required*	2
Number of injection well	1
Number of pressure relief wells	1
Length of horizontal well	1600 m

** Assuming 2 seismic are required after the polymer injection.*

Table 8 Summary of the cost estimation for polymer-gel treatment cases considered for flow diversion option.

Case number	1	2	3	4
Time period of injection (days)	30	95	60	185
Amount and Time period of injection, (Mt) days	0.29	0.34	0.59	0.63
Depth at which polymer is injected (m)	1750	1750	1800	1800
Cost of polymer (M€)	0.92	1.08	1.88	2
Cost of crosslinker (M€)	3.09	3.63	6.29	6.72
Injection well: drilling new wells (M€)	20.40	20.40	20.45	20.45
Relief well: Re-use of abandoned wells (M€)	5.75	5.75	5.75	5.75
Injection well and relief well operation cost (M€)	0.05	0.16	0.10	0.31
Well plugging after the injection (M€)	2.90	2.90	2.90	2.90
Cost of seismic monitoring (M€)	1.28	1.28	1.28	1.28
SUM (M€)	34.39	35.20	38.65	39.41

Table 9 Summary of the cost estimation for polymer-gel treatment cases considered for caprock fracture remediation.

Case number	5	6	7	8	9	10
Time period of injection (days)	20	30	360	210	400	500
Amount and Time period of injection, (Mt) days	0.15	0.24	0.27	2	0.4	3.2
Depth at which polymer is injected (m)	1500	1550	1550	1600	1600	1800
Cost of polymer (M€)	0.48	0.76	0.86	6.36	1.27	10.18
Cost of crosslinker (M€)	1.6	2.55	2.88	21.33	4.27	34.14
Injection well: drilling new wells (M€)	20.19	20.22	20.22	20.26	20.26	5.75
Relief well: Re-use of abandoned wells (M€)	5.75	5.75	5.75	5.75	5.75	5.75
Injection well and relief well operation cost (M€)	0.03	0.05	0.60	0.35	0.66	0.29
Well plugging after the injection (M€)	2.90	2.90	2.90	2.90	2.90	2.90
Cost of seismic monitoring (M€)	1.28	1.28	1.28	1.28	1.28	1.28
SUM (M€)	32.24	33.51	34.49	58.23	36.40	60.29

SECTION II

SEALANT DELIVERY USING HYDRAULICALLY CREATED FRACTURES

5 INTRODUCTION

In MiReCOl project, new methods to remediate CO_2 leakage using sealant and faults have been studied. In particular, it was evaluated to establish if it is possible to use hydraulically created fractures to transport sealant gel (or foams) to a leaky faults or, more in general, to a leaky areas or to create an impermeable horizontal barrier. In the literature, it is possible to find many publications that describe methods of intervention on leaking wells, like wellhead repair, patching casing and more, because leaking wells are probably to most common situation that leads to CO_2 migration to the surface. Figure 24 presents different leakage mechanisms in CO_2 storage (Tongwa et al., 2013).

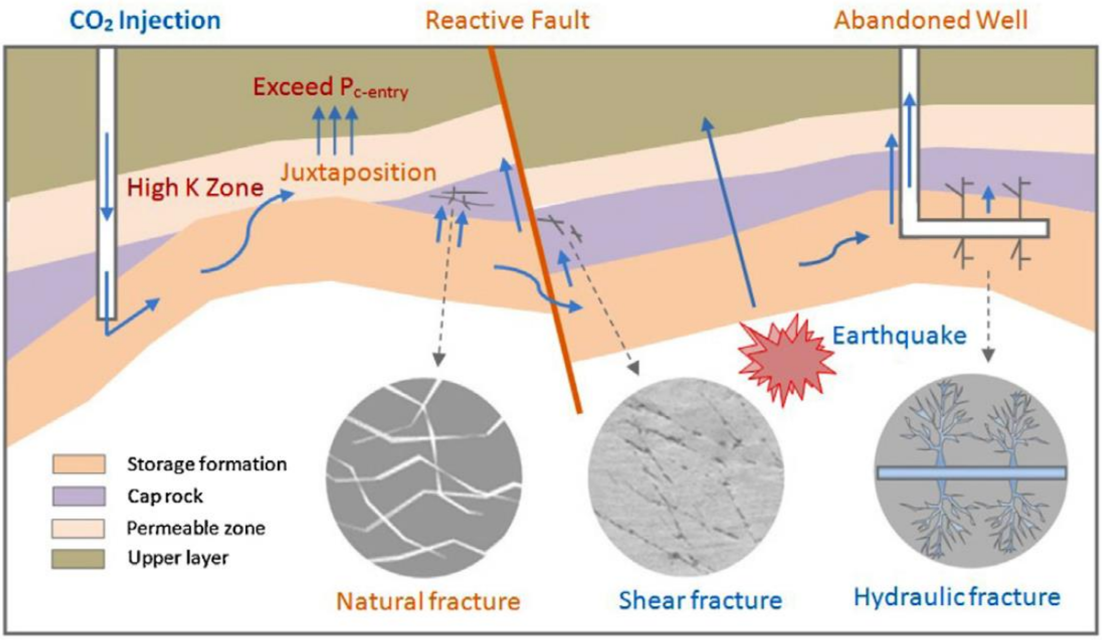


Figure 24 Possible CO_2 leakage mechanisms: through naturally occurring high permeability zones, through natural conduits and wells (after Tongwa et al., 2013).

This report does not address CO_2 leakage through wells, but other problematic cases: for example through caprock failings or leaking faults and fractures or high permeability areas. The most common solution adopted in these situations is perhaps to relieve the pressure in the CO_2 storage formation. Decreasing the pressure in the formation by dissolving CO_2 or stopping the injection of CO_2, can be a successful technique to reduce the leakage or avoid that the CO_2 reaches potentially dangerous area, like faults or highly permeable layers. In some cases this system might not be enough to prevent leakage, and other approaches, such as drilling new injection wells may be necessary. Research carried out under this part of the project investigated the possibility of transporting sealing material, such as gel-based polymers or foam, through hydraulically created fractures to the leaking location. Polymers and foam have been already used to seal leaking wells, but the plume penetrates the matrix only for few inches because of the low applied pressures. Geopolymers have the capability to resist to corrosion and the chemical resistance to CO_2 over a long period of time. For this reason, these polymers are already a valid option to substitute the conventional cements in CO_2 sequestration wells. Several potential fracture sealing materials have been already texted. In particular in Tongwa et al. (2013) the focus was on materials that can seal or at least reduce the permeability of faults and fractures. In their paper they have shown that paraffin wax, silica- and polymer-based gel and micro-cement have the capability to significantly reduce the fracture permeability. They conclude that for fractures larger than 0.5 mm, the micro-cement would be the material of choice to seal CO_2 leakage pathways, despite this cement might not be chemically stable because of carbonation. In case of smaller cracks, with width smaller than 0.25 mm, polymer gels with a polymer concentration between 4,000 and 8,500 ppm are efficient sealants and chemically stable when in contact with CO_2. In this project a model was built using the commercial software MFRAC to study how well one can distribute the sealant and how far one can take it by creating a hydrofracture, implementing the mechanical properties of the polymer gel or the micro-cement. The performance of different kind of sealing materials, in combination or not with a proppant, was investigated to determine the ones that better deliver this new technique.

5.1 The p18 field

5.2 Geology

As already mentioned in the introduction, the P18 field is located offshore, around 20 km off the coast of the Netherlands, in proximity of the port of Rotterdam. This field is contained into sandstones from the Triassic age, below impermeable layers of clay. This field is divided into 3 main blocks, bounded by a system of NW-SE oriented normal faults. The top of these 3 blocks is in between 3175 and 3455 m depth below sea level. The area that comprehend the P18 field is very faulted and consist on fault bounded compartments. Production data indicate that most of the faults between the various compartments are sealing, at least on production time scale. The cap rock (primary seal) of the P18 is 150 meters thick and it directly covers the reservoir's blocks. In the overburden, directly above the primary seal, it is present a secondary seal, the Altena group, which is roughly 500 meters thick. The remaining of the overburden is constituted by different geological formations, some of which also have sealing properties. In figure 25 and 26, taken from (Arts et al. 2012) it is presented the geology and a 3D view of the P18 gas field.

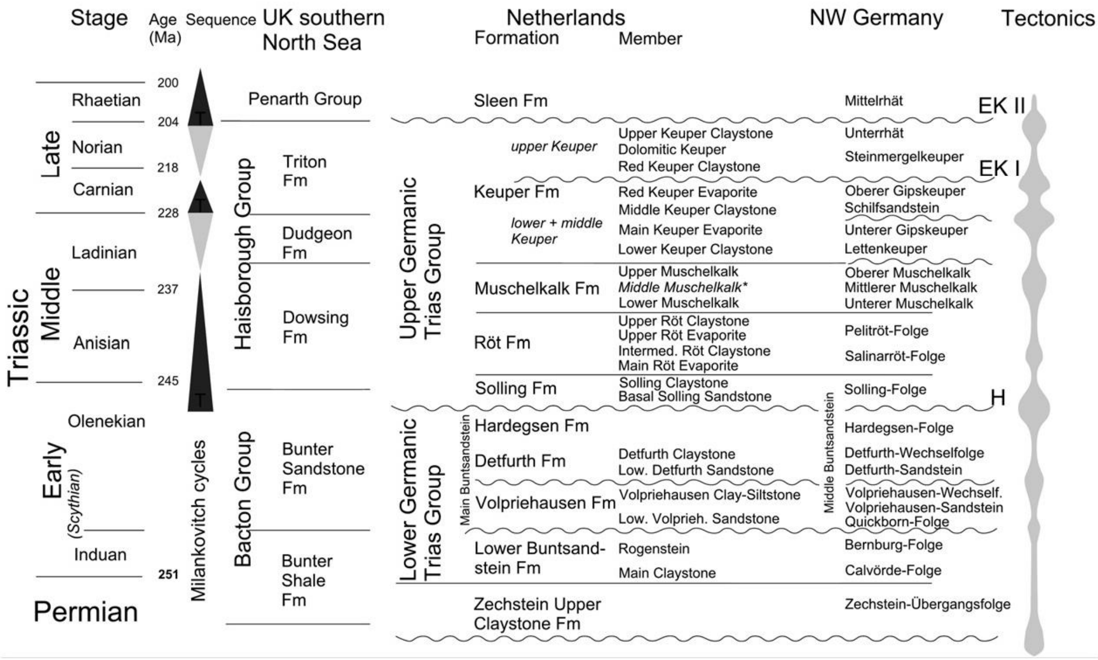


Figure 25 Overview of group and formation names and stages and sequences.

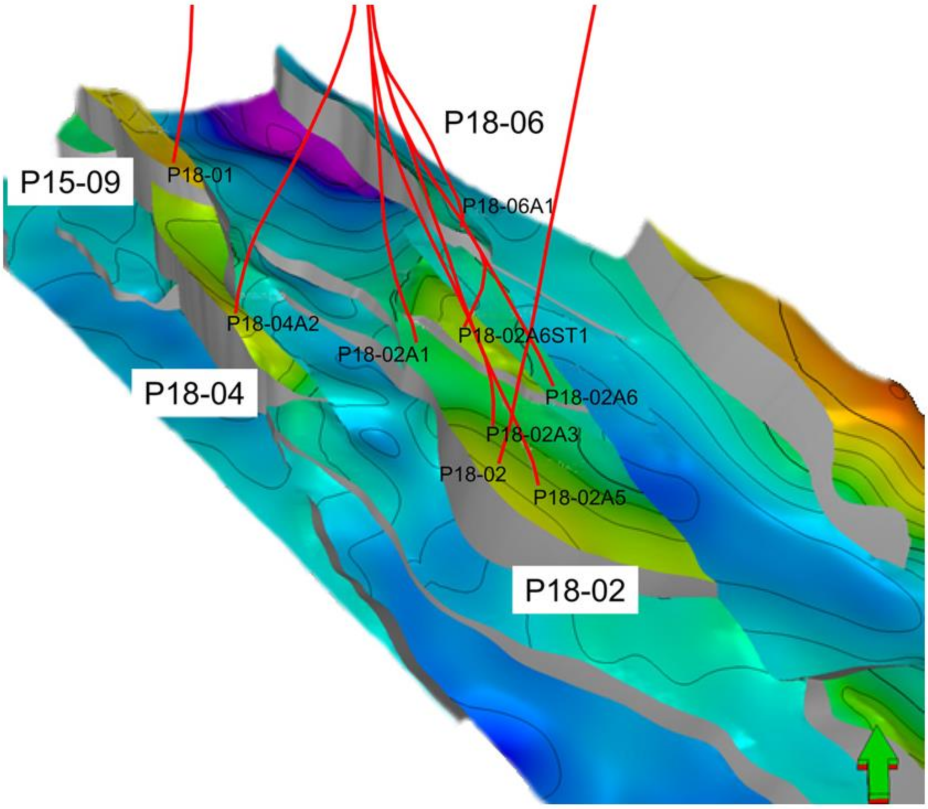


Figure 26 3D view of the top of the P18 fields. Faults are shown in grey, well traces are shown in red.

For a more detailed description of the geology, the available data and the studies about the P18 field that already have been made, refer to (Arts et al., 2012 and Brouwer et al., 2011).

5.3 Leakage scenarios

Several CO_2 migration scenarios have already studied in the *Feasibility study P18 (final report)* (Brouwer et al., 2011) (in Chapter 8), to determine the risk of migration of CO_2 through the overburden. In particular 3 migration paths had been taken into account: through the aquifer spill reservoir, through an induced fracture into the primary seal with a migration of CO_2 into the sandstone and through a wellbore shortcut. For these migration analysis it has been built and used a Petrel model of the overburden. In this study it has been concluded that the most plausible migration pathway of the stored CO_2 to the surface is via leaking wells and that the CO_2 would reach directly the atmosphere through the wells and not via pathway that developed within the overburden. Despite the conclusion of the *Feasibility study P18* (Brouwer et al., 2011), we believe that the structure and geology of the P18 reservoir is optimal to simulate as well the case of CO_2 leakage through existing faults. Case that is ideal to test the method, use hydro-fractures to transport the sealant to a leaking location that we want to apply.

5.4 Methodology

There are already many different mitigation and remediation technologies to apply in case of unwanted migration of CO_2 from CO_2 geological storage units. Some of them have already been used in real cases, while others only in laboratory tests. An interesting overview of these different techniques can be found in (Manceau et al., 2014). The characteristics, the viscous, mechanical and chemical properties of polymer gels match perfectly the needs of a method to mitigate leakages. Our idea is to create and use hydro-fractures to transport the sealant gel to the leaky fault to mitigate or remediate the CO_2 leakage. Another interesting option would be to stimulate a horizontal hydro-fracture to create a sort of blanket that act like an impermeable barrier (see Figure 27). This would be possible only for shallower reservoir than the P18 field because at the depth of the P18 reservoir the vertical stresses would be too high to create a horizontal fracture.

We will perform the numerical simulations with the software MFRAC. After creating the 1D geomechanical model of a section of the P18 field, we will import the 1D model into the software and we will try different kind of injection rates and replace the proppant by polymer based gels. Playing with different viscosity, mechanical and chemical properties of the gel and with different injection rate of the fluid, we want to study how far, how well and how accurate we can transport the sealant to a leaky location. We do not want to constrain the results of our study only to the P18 gas field, but to define which parameters control the effectiveness of the 2 methods that we proposed, to allow operators to use these solutions also for other fields.

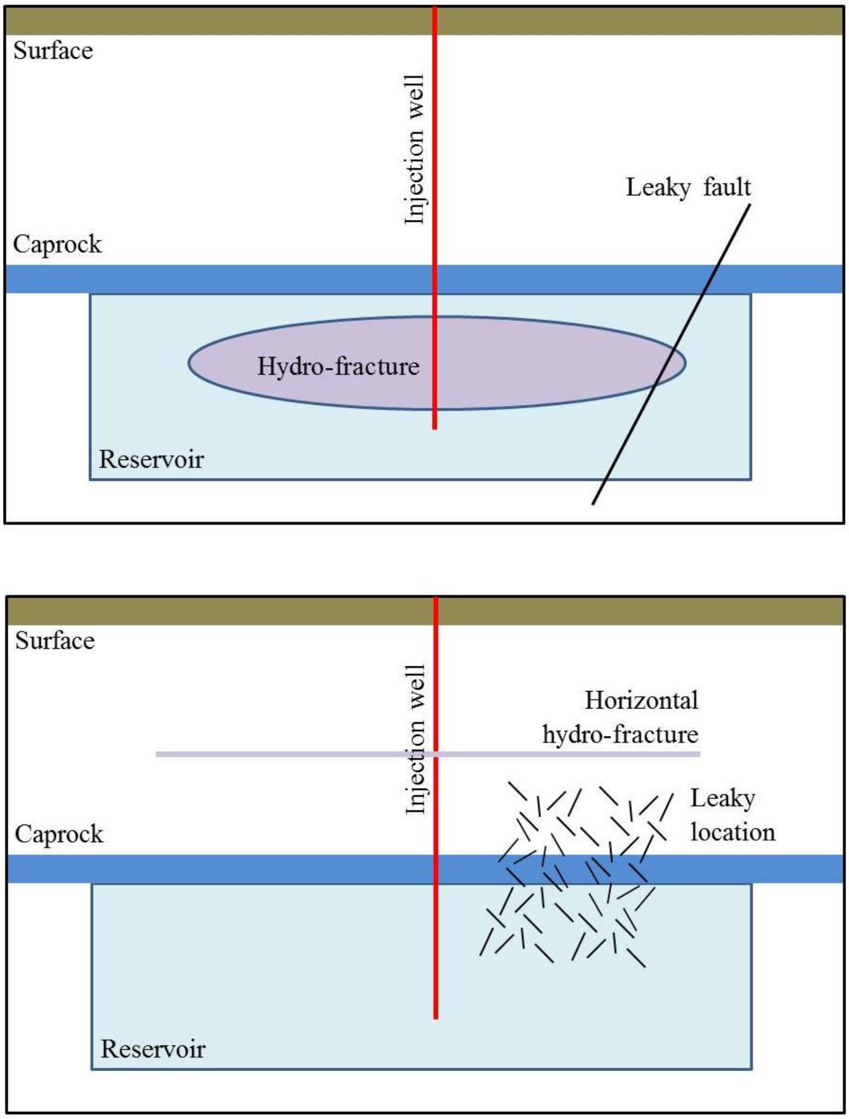


Figure 27 Schematic representation of the methods.

5.5 SELECTION OF THE MODEL

We decided to proceed with the first model that has been presented in the previous section (inducing a hydrofracture to transport the sealant to the leaky location). Before beginning to develop such a model, we analysed the advantages and disadvantages of this approach.

We want to reach a leaking fault (or fracture) in the reservoir and spread as more sealant as we can on a surface as wide as possible. Faults and fractures are surrounded by a damaged zone with permeability much higher than the reservoir (up to 10 times higher) and we can use this higher permeability to spread the sealant polymer on a wider surface.

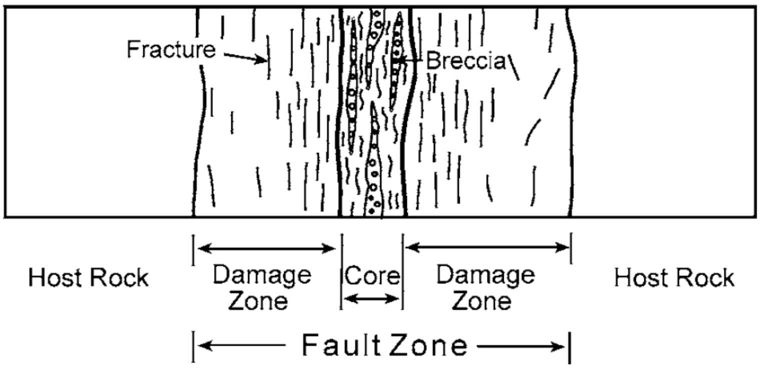


Figure 28 The fault zone is composed of 2 main mechanical units: a core and a damaged zone. (Gudmundson, 2003).

The first important choice we needed to take it was about the orientation of the well: vertical or horizontal.

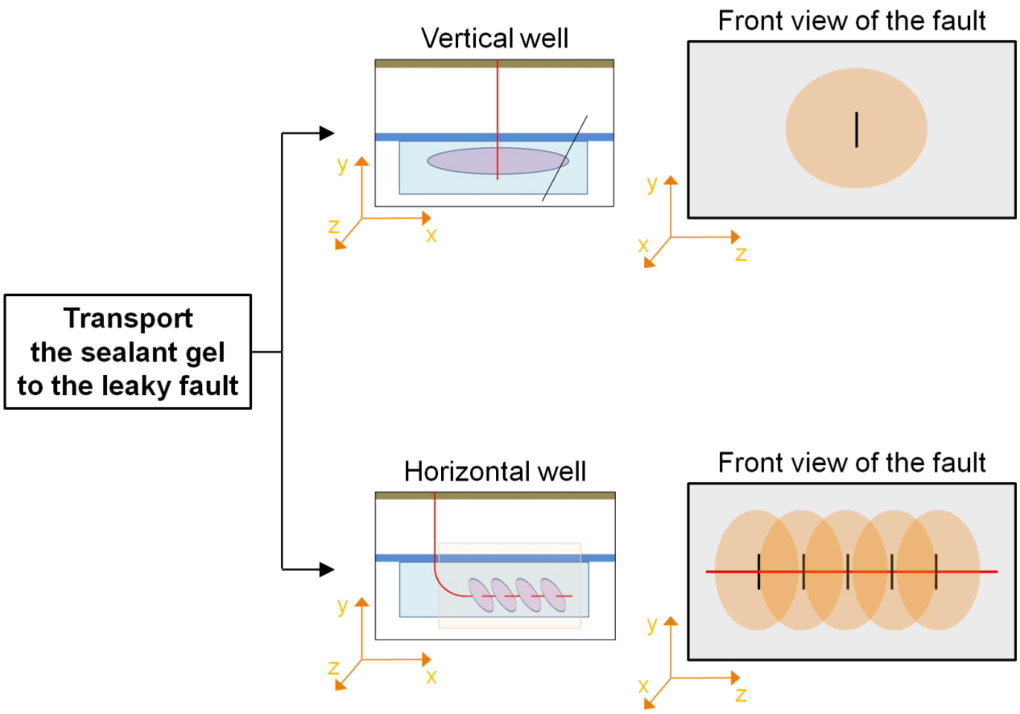


Figure 29 Hydraulic fracturing via vertical or horizontal well.

If we hydrofracture the reservoir using a vertical well, we can induce one hydrofracture at the time. Because of that we need to locate the leaking area with good precision to be able to transport the sealant where it is needed. With an horizontal well it is possible to create several hydrofractures simultaneously. In this case we can potentially cover a much wider area of the fault's surface with the sealant. On the other hand, because of the high permeable damaged zone around the fault's surface, a single hydrofracture might also be enough to reach the degree of mitigation that we desire. Unfortunately in out model it was not possible to incorporate the higher permeability of the damaged zone. Therefore we can only speculate about the influence that the enhanced permeability of the damaged zone has on the surface of the fault that it is covered by the sealant. As final remark, it is important to keep in mind that to drill an horizontal well it is much more expensive than a vertical one and that, at least in the case of the P18-4, the vertical well is already in place without the need of any extra costs.

The second choice was related to the location of the hydrofracture: above or inside the reservoir. This choice is strictly correlated with the weight of the sealant polymer that it is used to create the hydrofracture.

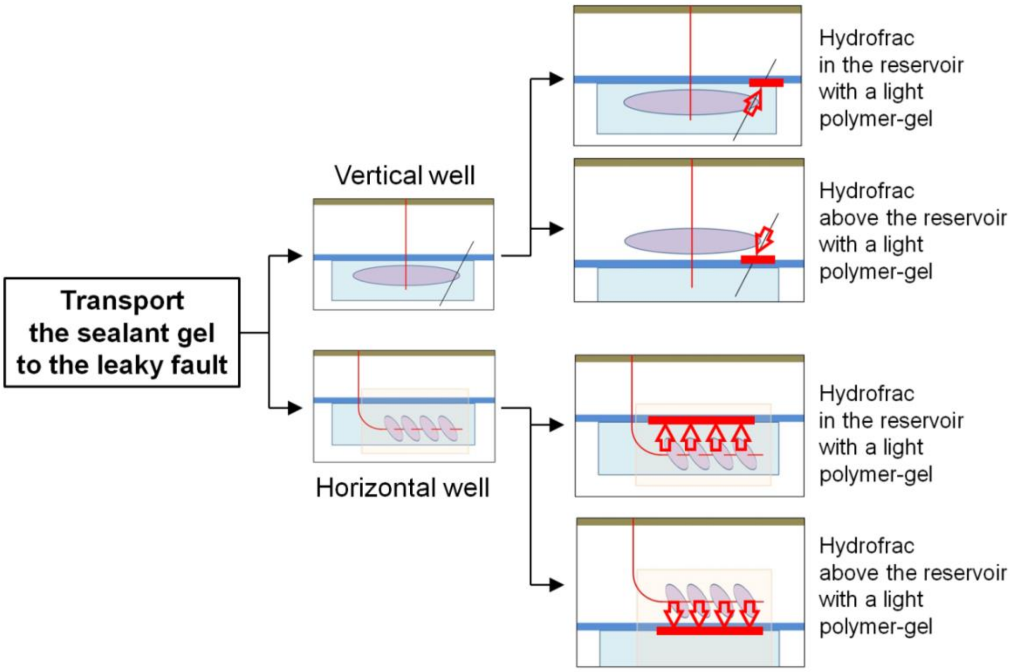


Figure 30 Hydraulic fracturing above (with heavy polymer-gel) or within (with light polymer-gel) the reservoir.

If we provoke an hydrofracture within the reservoir, we have to be careful to not damage the caprock. We have to take in some way under control the vertical propagation of the hydrofracture. If we hydrofracture above the reservoir we would not risk to damage the cap rock. Another advantage of hydrofracturing above the caprock is related to the rock permeability: within the reservoir the permeability is much higher than above the caprock and it is much more complicated to hydrofrac a rock with high permeability than a rock with low permeability (because of the leak off). For the P18-4 case, for example, above the caprock the permeability of the rock matrix is in the range of the 0.1 mD and within the reservoir is in the range of 150 mD. In case we would induce an hydrofrac within the reservoir, we would choose a light polymer as sealant (to have a flow in the direction of the surface) while for the other case, fracturing above the caprock, we would need a heavy polymer, to have a flow in opposite direction and to reach the leaking fault from the top.

Considering the physical advantages and disadvantages together with the financial considerations and with the fact that probably no institution would allow to hydrofrac above the caprock, especially it is already leaking, we decided to model the case with the vertical well and to hydrofrac within the reservoir using a light polymer gel.

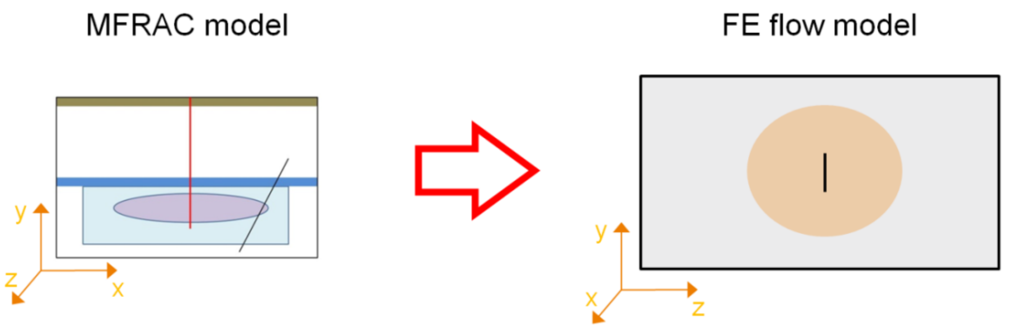


Figure 31 Modelled scenario: vertical well and hydrofracture inside the reservoir.

5.6 RESULTS

The P18-4 well has been modelled using the commercial software MFRAC.

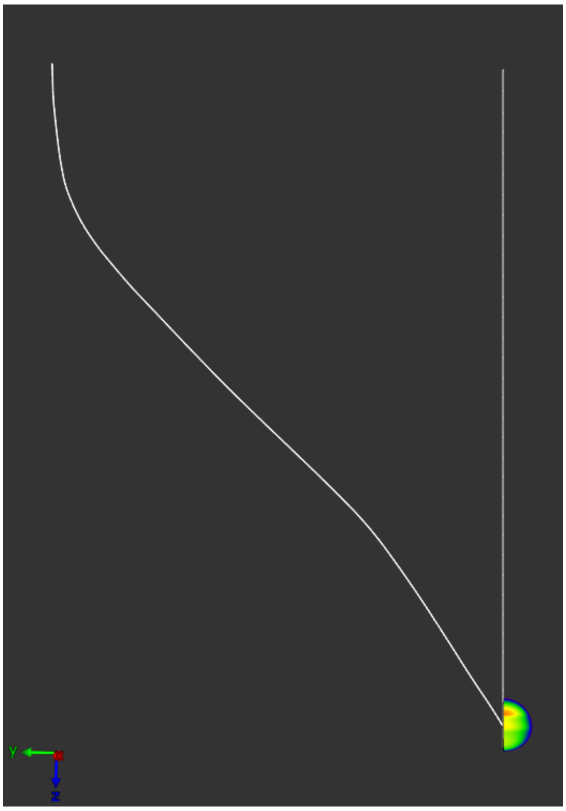


Figure 32 Side view of the well P18-4 in MFRAC with an hydraulically induced fracture.

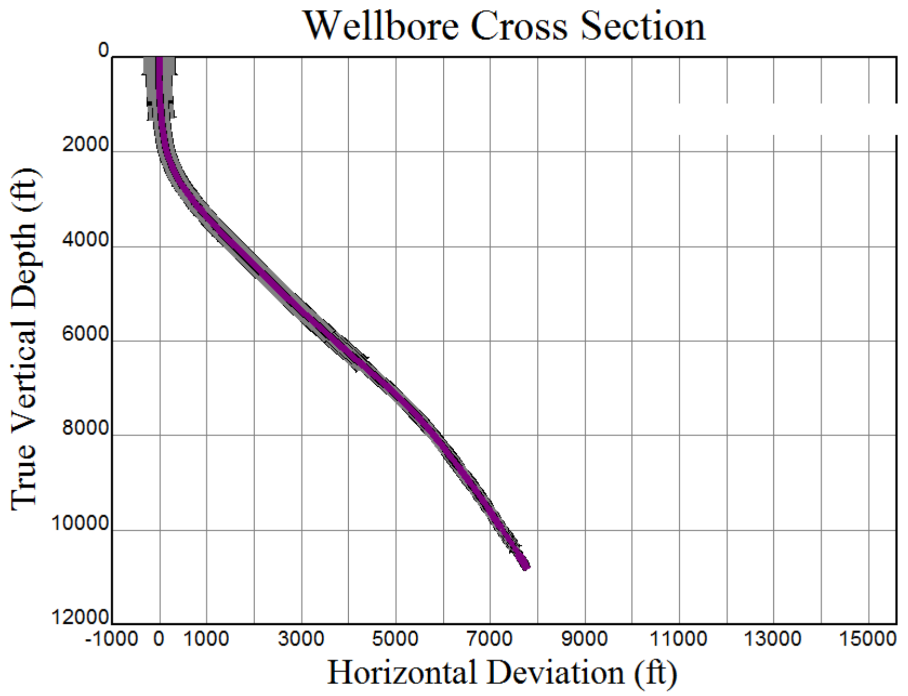


Figure 33 P18-4 wellbore cross section.

The mechanical properties adopted are shown in Figure 34.

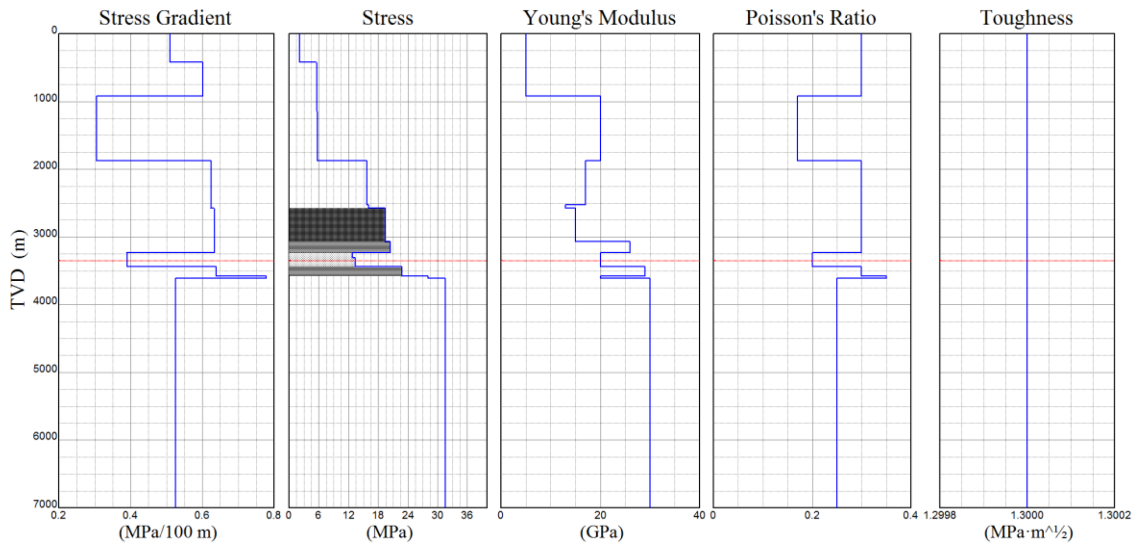


Figure 34 Mechanical properties. The red line indicates the perforations interval (3340-3355 m TVD).

For the reservoir has been considered a permeability of 100 mD.

To induce the hydrofracture, we considered 100 perforations of 0.39 inches of diameter between 4244 m and 4261 m MD (3340-3355 m TVD).

In Figure 35, 36 and 37 it is presented the treatment schedule that has been adopted to perform the crack job.

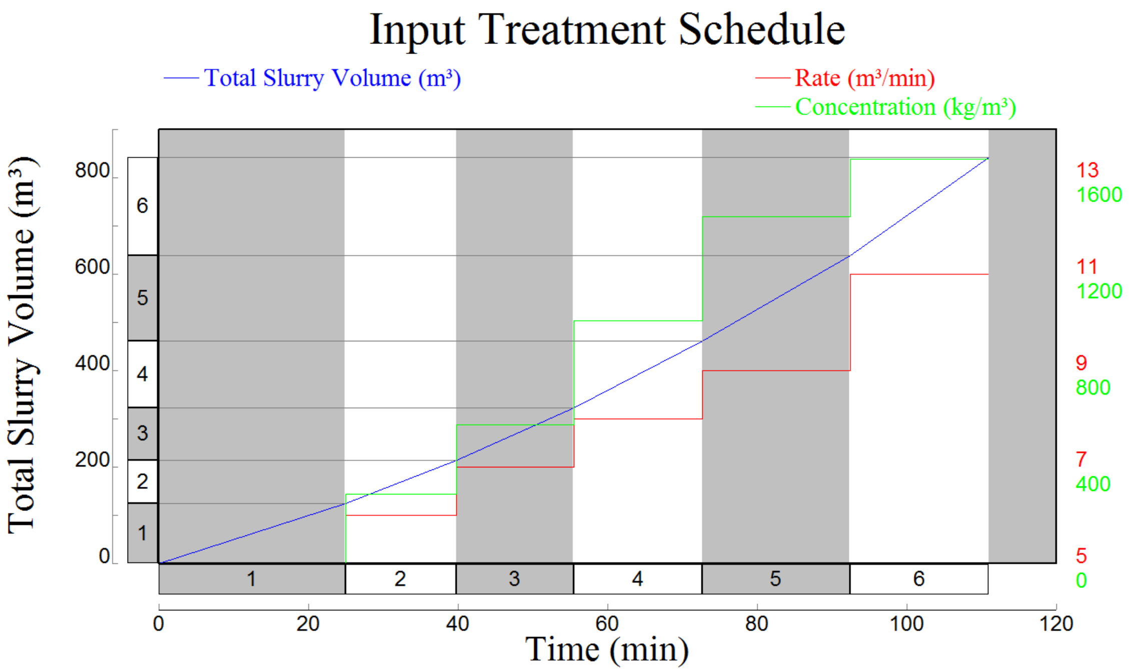


Figure 35 Input treatment schedule: tot al slurry volume, rate and concentration.

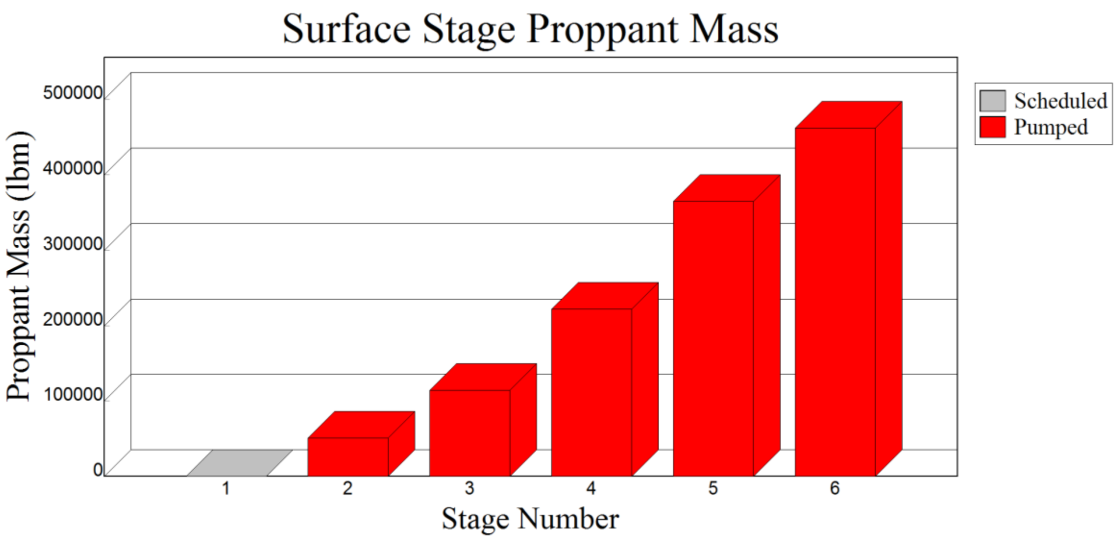


Figure 36 Input treatment schedule: surface stage proppant mass.

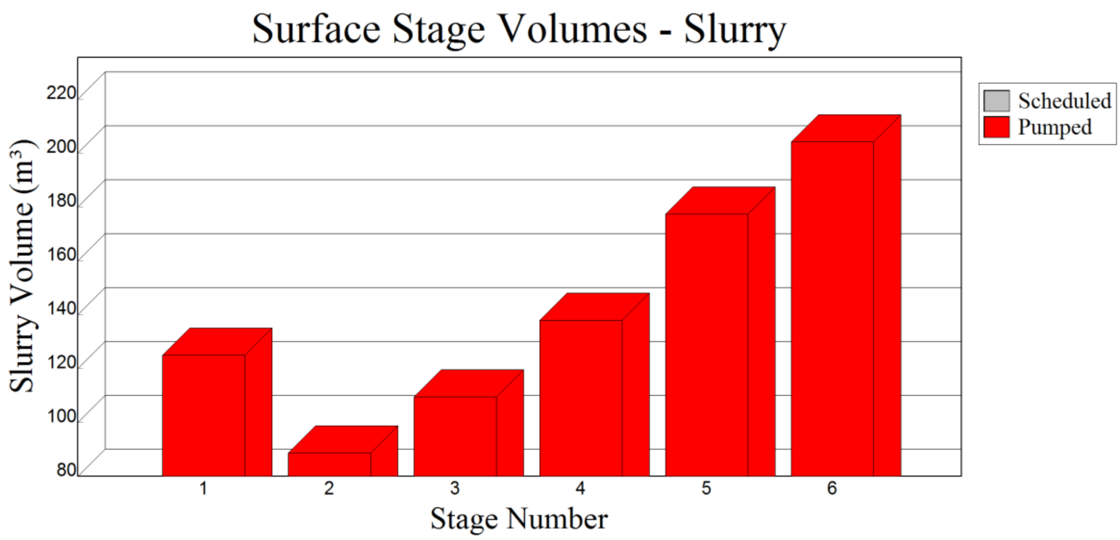


Figure 37 Input treatment schedule: surface stage volumes for the slurry.

As it has been mentioned earlier in this report, we are hydrofracking an exhausted reservoir that has high permeability. For this reason the leak off is high and therefore unfavourable to perform a crack job. The distance that we can reach with the sealant strongly depends on the leak off coefficient. For low leak off coefficient the crack develops along the border with the caprock. For higher values of the leak off, the crack does not risk to penetrate into the caprock.

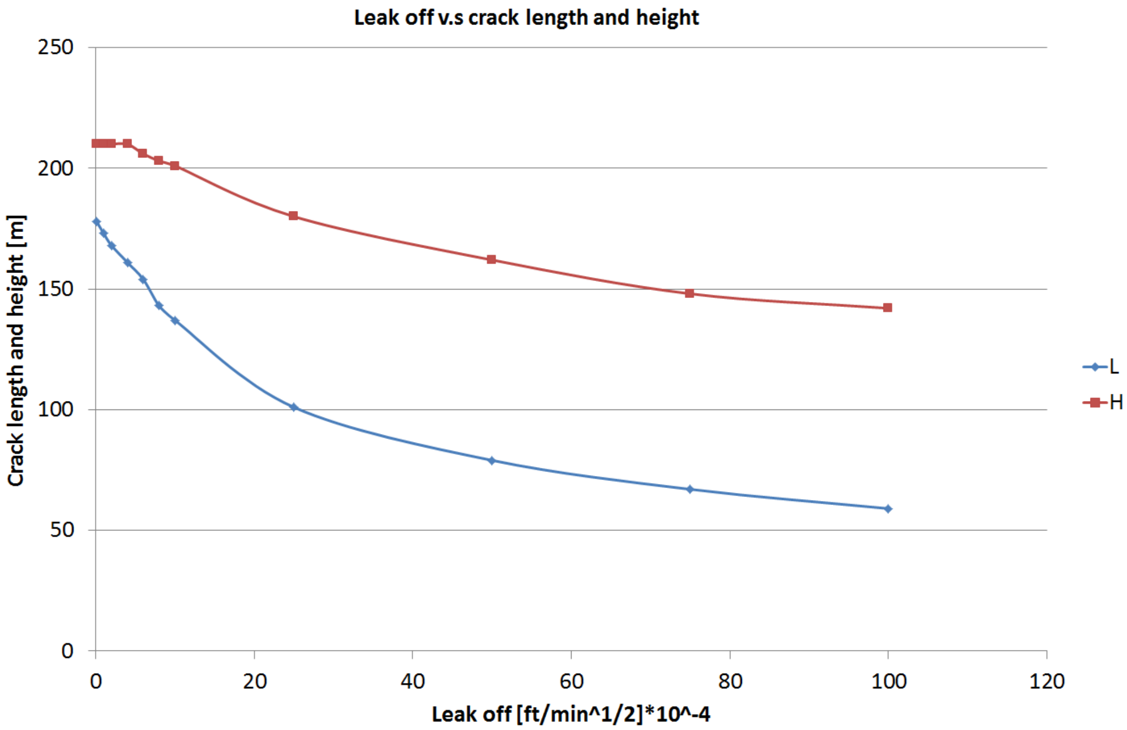


Figure 38 Leak off versus crack length and height.

As it is shown in Figure 38, in the geological configuration of the P18 field, the hydrofracture tends to develop more in the vertical direction than in the horizontal direction. In the figure below it is shown the shape of the hydrofrac related to the leakoff of 10^{-5} ft/min^$^{1/2}$.

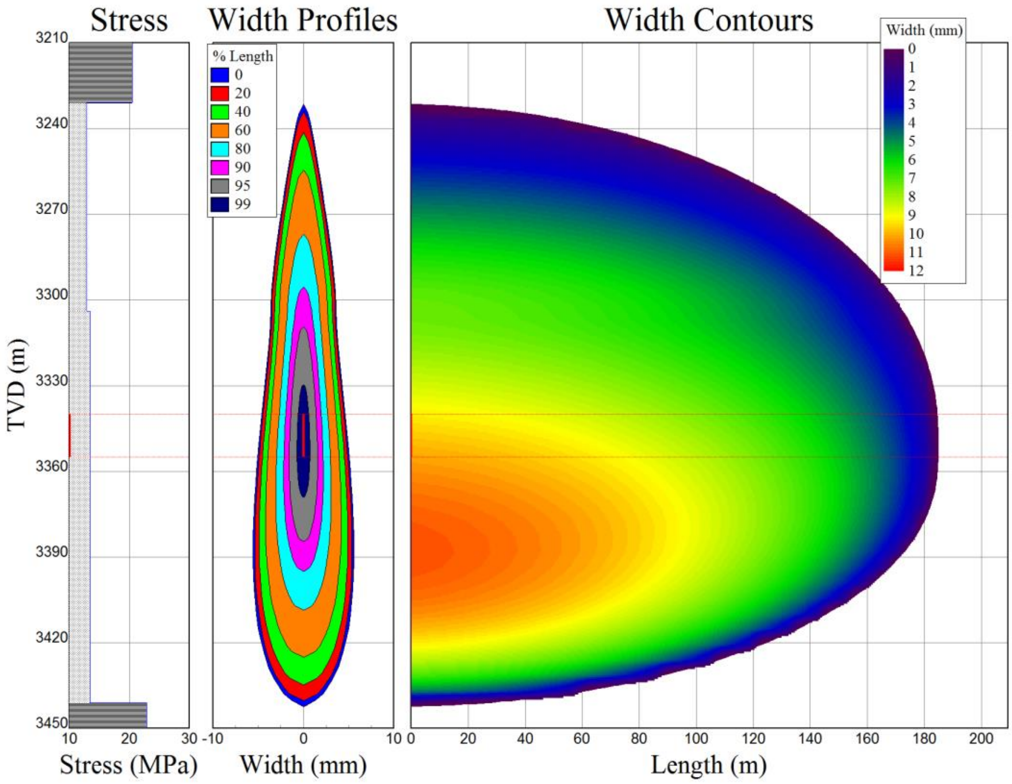


Figure 39 width and length of an hydrofracture (leak off 10^{-5} ft/min^$^{1/2}$).

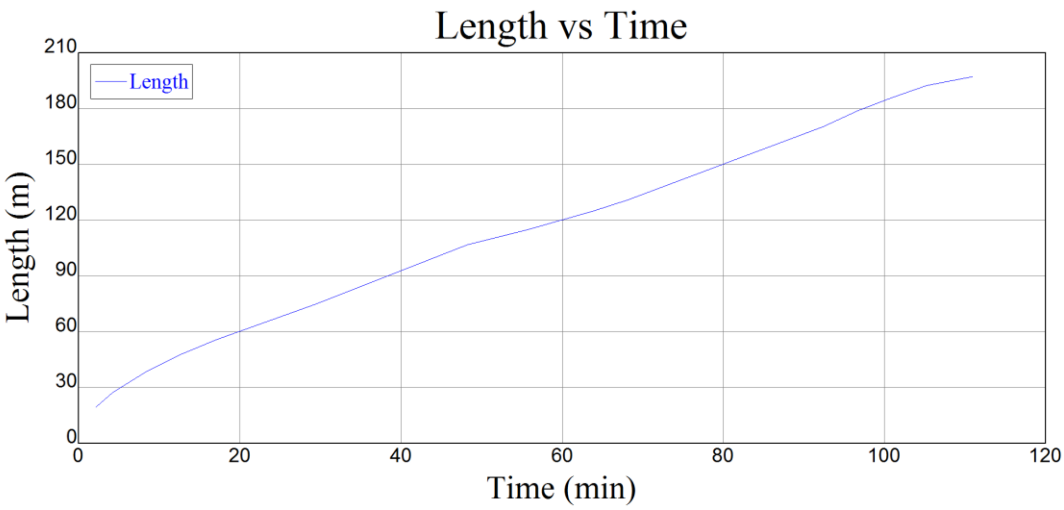


Figure 39 Fracture length versus time.

In this situation we created a fracture 185 meter long. Assuming, for example, to intersect the leaking fault after 140 meters, we would be able to cover 26500 m2 with the sealing polymer. The surface of the leaking fault that is covered by the sealing polymer obviously depends from the distance of the leaking fault from the injection well.

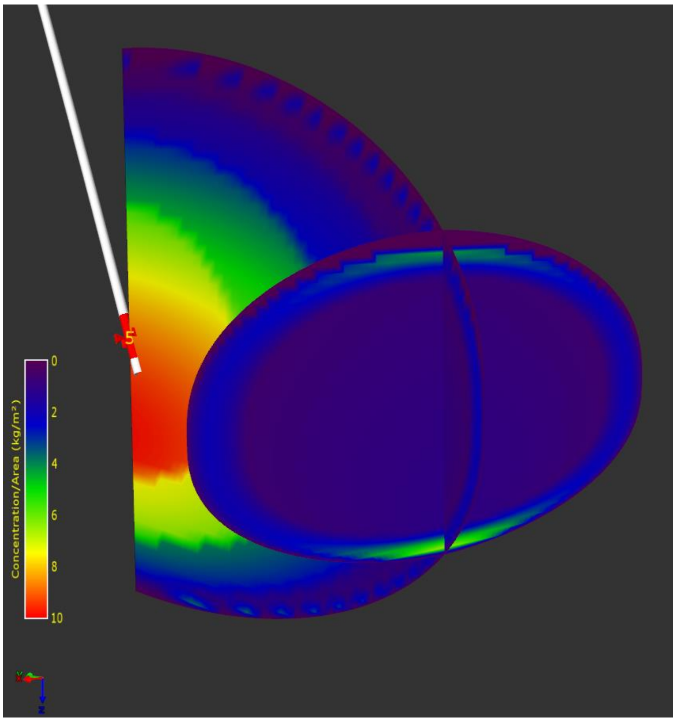


Figure 40 Area of the leaking fault covered by the sealing polymer.

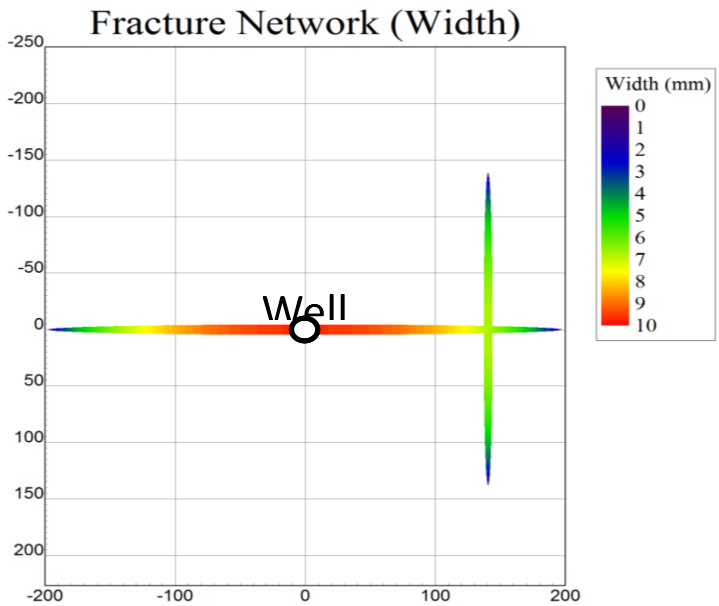


Figure 41 Top view of the fracture network (hydrofracture and leaking fault).

This method can result also successful if the well would be placed inside a block in the reservoir. In this case the sealant would also be transported in the lateral walls (faults) of the block. To analyse this case we adopted the treatment schedule shown in Figure 42.

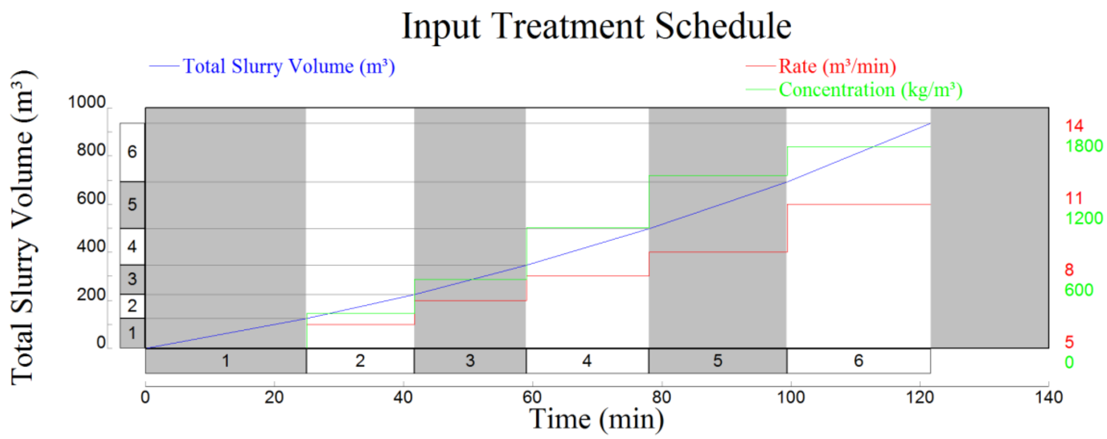


Figure 42 Input treatment schedule: tot al slurry volume, rate and concentration.

Under these circumstances we developed an hydrofracture 112 meters long that intersect a leaking fault after 78 meters. The fault surface cover with the sealing polymer will be of 20600 m^2.

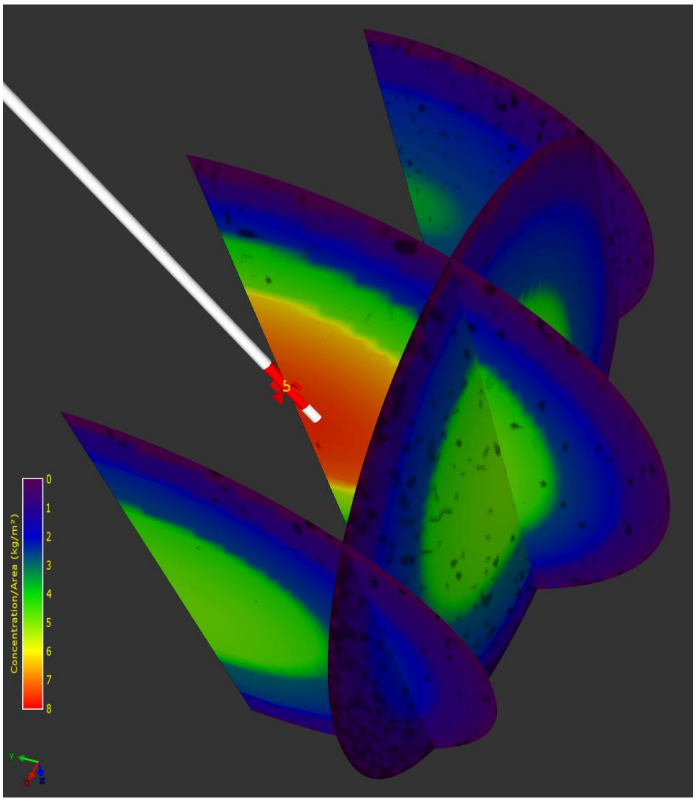


Figure 43 Area of the leaking fault covered by the sealing polymer.

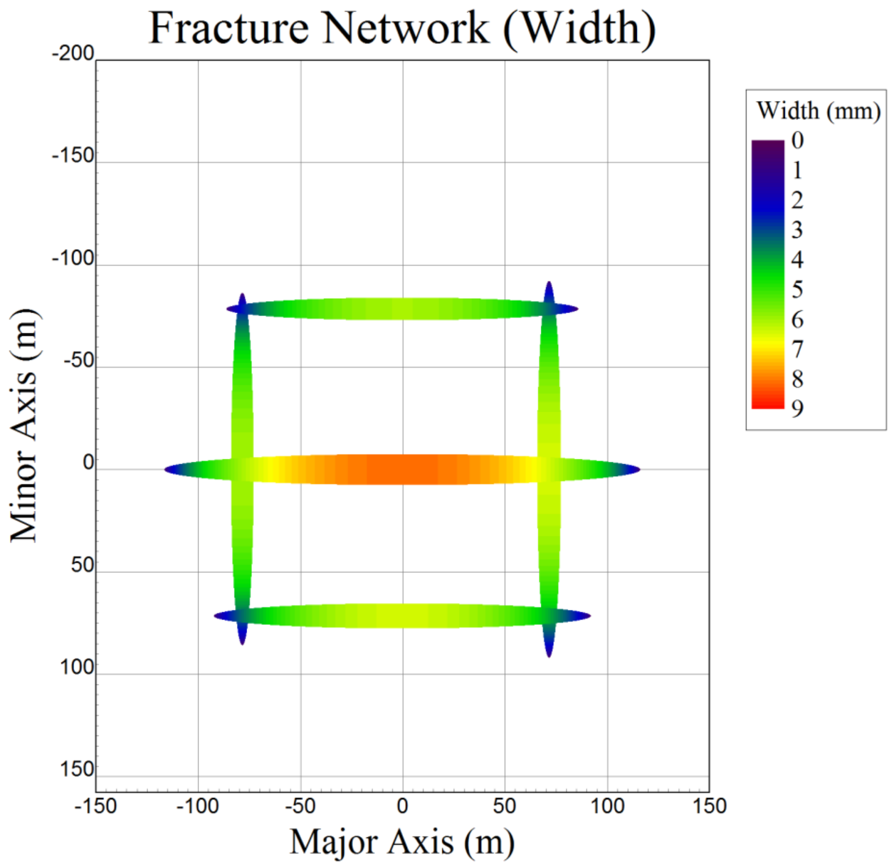


Figure 44 Top view of the fracture network (hydrofracture, leaking fault and lateral faults).

6 CONCLUSIONS

This report presented two different approaches to leakage remediation using sealants, namely the injection of sealants from wells and transport through porous structures and the use of hydraulically created fractures to deliver the sealants to leaky zones as the second alternative.

The results obtained from numerical simulations using the UTCHEM simulation software show that the area of influence increases with the decrease in crosslinker concentration for a given polymer concentration. This is mainly due to the decreased viscosity and slower gelation rate.

The results of polymer-gel injection using Eclipse (E300) show that polymer-gel injection (with delaying agents) from a horizontal well close to the leaky fault and directly above the caprock can effectively remediate the CO_2 leakage through a leaky sub-seismic fault in the caprock.

For the cases of flow diversion within the storage reservoir, the simulation results show that increasing the period of injection, potentially clogs the CO_2 injection well when the polymer is injected at the bottom of the reservoir. Therefore, polymer injection just below the caprock using the horizontal well configuration was found to be more suitable.

For the cases of polymer injection above the caprock, simulation results show that polymer injection from CO_2 injection well, which is at a distance of approximately 1k from the leaky fault, is the least favourable option as the duration of polymer gel treatment (500days) and volume of polymer solution required would increase the cost of operation significantly.

In conclusion, an appreciable reduction in CO_2 leakage was achieved depending on the permeability reduction caused by the polymer-gel treatment.

In the second section where hydraulically created fractures were tested to deliver the sealants to leaky zones the P18 field was used as a real case scenario and the methodology proposed was described. The advantages and disadvantages of this approach were discussed. The results have shown that this method (combined with a proper choice of a polymer gel) can be an option to mitigate CO_2 leakage of a leaking fault. This model has, of course, some limitations. For example, the work could only considered vertical faults and it was not possible to introduce the enhanced permeability of the damaged zone that surrounds a fault.

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