Project no.:
608608

Project acronym:
MiReCOL

Project title:
Mitigation and remediation of leakage from geological storage

Collaborative Project

Start date of project: 2014-03-01
Duration: 3 years

D5.3

Remediation of leakage by diversion of CO_2 to nearby reservoir compartments

Revision: 2

Organisation name of lead contractor for this deliverable:
TNO

Project co-funded by the European Commission within the Seventh Framework Programme		
Dissemination Level		
PU	Public	X
PP	Restricted to other programme participants (including the Commission Services)	
RE	Restricted to a group specified by the consortium (including the Commission Services)	
CO	Confidential , only for members of the consortium (including the Commission Services)	

MiReCOL Mitigation and Remediation of CO_2 Leakage

Deliverable number:	D5.3
Deliverable name:	Remediation of leakage by diversion of CO_2 to nearby reservoir compartments
Work package:	WP 5: Remediation linked to transport properties of faults and fracture networks
Lead contractor:	TNO

Status of deliverable		
Action	**By**	**Date**
Submitted (Author(s))	B. Orlic	31.10.2016.
	D. Loeve	05.08.2016
	E. Peters	05.08.2016.
Verified (WP-leader)	B. Orlic	31.10.2016.
Approved (SP-leader)	M. Fleury	31.10.2016

Author(s)		
Name	**Organisation**	**E-mail**
B. Orlic	TNO	bogdan.orlic@tno.nl
D. Loeve	TNO	daniel.loeve@tno.nl
E. Peters	TNO	lies.peters@tno.nl

Public abstract

The MiReCOL project investigates existing and new techniques for remediation and mitigation of leakage from geological CO_2 storage. Assessment of potential leakage through faults and fractured caprocks is of primary concern for geological CO_2 storage sites. Faults and fracture networks can act either as permeability barriers or preferential pathways for fluid flow, depending on the infill and the stresses acting on them. Hence, faults and fractures can be open and conductive at some time and closed and non-conductive at other times.

This study describes mitigation of leakage by diverting CO_2 from the storage compartment to nearby reservoir compartments through fractures. Study results are published in an Energy Procedia paper presented at the 13th International Conference on Greenhouse Gas Control Technologies (GHGT-13) held in Lausanne in 2016 (*Loeve et al., 2016, Diversion of CO_2 to nearby reservoir compartments for remediation of unwanted CO_2 migration)*. The mitigation method requires creating a pathway for fluid migration between the injected, leaky compartment and neighbouring compartments, as the injected and neighbouring compartments are originally not connected. Compartmentalized gas reservoirs or aquifers represent geological settings potentially suitable for remediation by flow diversion. Such structural settings are quite common in the Dutch and the North Sea reservoirs; for example, the depleted P18-4 gas reservoir, planned to be used for CO_2 storage in the Rotterdam Capture and Storage Demonstration Project (ROAD), is separated by a sealing fault from the neighbouring P15 depleted gas field. Another example relevant for CO_2 storage in both depleted gas fields and aquifers, are the Rotliegendes reservoir rocks, which are compartmentalized throughout the North-western Europe.

Our study demonstrates that in the event of significant irregularities and leakage from a CO_2

storage site, pressure relief can be achieved by diverting the CO_2 from the storage compartment to non-connected parts of the reservoir, or to adjacent reservoirs and aquifers. Fluid migration between the two originally non-connected reservoirs could be enabled by hydraulic fracturing across a sealing fault that separates adjacent compartments, or by drilling a well or laterals. The effects of flow diversion as a remediation option are evaluated through numerical simulations of idealized synthetic case and a real field case from the North Sea. The results show that flow diversion is a possible remediation option for a specific setup of depleted gas fields or saline aquifers, which is common in the Dutch and the North Sea portfolio of reservoirs. The key factors controlling the efficiency of flow diversion are the conductivity of the created pathways between the two reservoirs, the pressure difference between the reservoirs and the permeability of the receiving reservoir. In the case of CO_2 diversion into an undepleted saline aquifer, the remediation is relatively slow, compared to diversion into an adjacent depleted gas field, due to the small pressure difference between the two compartments. The simulations of the real case show that the diversion strategy needs to be optimized for the specific conditions and structural setting of the storage site. For the conditions evaluated in the real case, the remediation using a well is much more effective than remediation using hydraulic fractures.

TABLE OF CONTENTS

SUMMARY

The MiReCOL project investigates existing and new techniques for remediation and mitigation of leakage from geological CO_2 storage sites. WP5 of this project is concerned with remediation options linked to transport properties of faults and fracture networks. This report is the third deliverable of WP5 (D5.3). The report investigates mitigation of leakage by diverting CO_2 from the storage compartment to nearby reservoir compartments through fractures. Deliverable D5.3 is published as an Energy Procedia paper presented at the 13th International Conference on Greenhouse Gas Control Technologies (GHGT-13) held in Lausanne in 2016 (*Loeve et al., 2016, Diversion of CO_2 to nearby reservoir compartments for remediation of unwanted CO_2 migration).*

13th International Conference on Greenhouse Gas Control Technologies, GHGT-13, 14-18 November 2016, Lausanne, Switzerland

Diversion of CO_2 to nearby reservoir compartments for remediation of unwanted CO_2 migration

D. Loeve, E. Peters, M.P.D. Pluymaekers, F. Jedari-Eyvazi, F. Neele, B. Orlic

Abstract

In the event of significant irregularities and leakage from a CO_2 storage site, pressure relief can be achieved by diverting the CO_2 from the storage compartment to unconnected parts of the reservoir or to adjacent reservoirs and aquifers. Fluid migration between the two originally unconnected reservoirs could be enabled by hydraulic fracturing across a sealing fault that separates adjacent compartments or by drilling a well or laterals. The effects of flow diversion as a remediation option are evaluated through numerical simulations of an idealized synthetic case and a real field case from the North Sea. The results show that flow diversion is a possible remediation option for a specific setup of depleted gas fields or saline aquifers, which is common in the Dutch and the North Sea portfolio of reservoirs. The key factors controlling the efficiency of flow diversion are the conductivity of the created pathways between the two reservoirs, the pressure difference between the reservoirs and the permeability of the receiving reservoir. In the case of CO_2 diversion into an undepleted saline aquifer, the remediation is relatively slow, compared to diversion into an adjacent depleted gas field, due to the small pressure difference between the two compartments. The simulations of the real case show that the diversion strategy needs to be optimized for the specific conditions and structural setting of the storage site. For the conditions evaluated in the real case, the remediation using a well is much more effective than remediation using hydraulic fractures.

1 INTRODUCTION

Geological CO_2 storage in depleted gas fields and saline aquifers is considered one of the most promising technologies for a low-carbon energy future. The goal of geological

CO_2 storage is permanent and safe storage of substantial quantities of CO_2 in the subsurface formations. In the event of undesired migration of CO_2 within or out of the storage reservoir, corrective measures need to be taken to mitigate the unwanted migration and reduce the possible consequences of a leak. The feasibility of existing and new techniques that are potentially relevant to remediation and mitigation of leakage from geological CO_2 storage sites has been investigated in the MiReCOL (*Mitigation and Remediation of CO_2 Leakage*) project (2014-2017; http://www.mirecol-co2.eu/). The aim of this project is to develop a handbook of corrective measures that can be considered in the event of undesired migration of CO_2 in deep subsurface reservoirs

In this study we investigate one possible corrective measure, which is diversion of the injected CO_2 from a leaky storage compartment to an adjacent compartment to achieve pressure relief in the storage formation. Although different remediation methods were considered in several earlier publications (e.g. [1-5]), flow diversion as a remediation option has to the best of our knowledge not been studied so far. A suitable structural setting for flow diversion comprises two reservoir compartments separated by a sealing fault (Fig. 1a). Flow diversion requires creating a pathway for fluid migration between the two originally unconnected reservoirs, which can be achieved, for example, by hydraulic fracturing across the fault or by drilling a well or lateral(s) (Fig. 1b). The creation of a pathway will cause pressure equilibration between the two compartments. In our analysis, we assume that the pressure reduction in the leaking compartment will be sufficient to stop unwanted migration of CO_2.

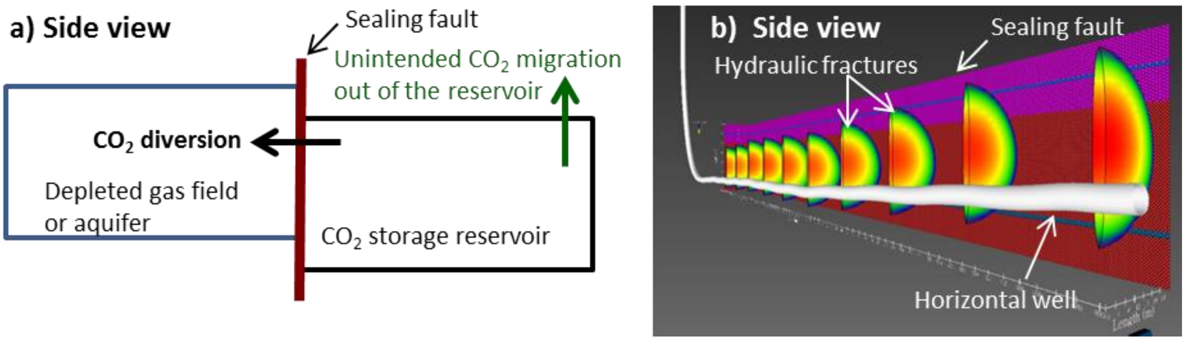

Fig. 1. (a) Schematic representation of the structural setting possibly suitable for flow diversion. The CO_2 storage reservoir and the depleted reservoir are separated by a sealing fault (side view). (b) Breaching of a fault seal by multi-stage hydraulic fracturing will enable flow diversion, i.e. lateral migration of fluids between the two adjacent reservoir compartments through fractures.

Remediation by flow diversion can be relevant for CO_2 storage in a depleted gas field, which is adjacent to other depleted gas fields. Structural settings where several depleted gas reservoirs or compartments are transected or separated by sealing faults are common for Dutch onshore fields, North Sea fields and many other petroleum provinces. Remediation by flow diversion can also be relevant for storage in aquifers with undetected sealing faults, which becomes apparent during the injection phase. In both cases, creating a flow conduit across the fault/barrier that separates the adjacent compartments will allow CO_2 and/or water to flow out of the storage compartment and therefore will lower the pressure.

In this paper, remediation by flow diversion is first analyzed using a synthetic test case and then applied to a real field case. The findings inferred from these cases are discussed. Finally, more general conclusions are drawn on the use of flow diversion as a remediation measure in the context of geological CO_2 storage.

2 MODEL SETUP AND PARAMETERS

Initial tests were performed on synthetic models. Then, the effectiveness of remediation by flow diversion is investigated on a real field case from the North Sea. This section provides description of the flow models, model parameters and simulation scenarios. Simulations of the synthetic case were conducted with ECLIPSE, while simulations of the real case were done with Shell's in-house reservoir simulator MoReS.

2.1 Synthetic case

The synthetic case comprises an idealized representation of two depleted, adjacent reservoir compartments separated by a sealing fault. CO_2 is injected into one of the compartments. At some point during injection, CO_2 starts leaking from the storage reservoir due to, for example, the presence of fractures within the caprock or leaky wells. After leak detection, it is decided to divert CO_2 into the adjacent compartment with a lower pressure, which has sufficient capacity to store the diverted CO_2. A long horizontal well is drilled parallel to the sealing fault, which separates the two reservoirs (Fig. 1b and Fig. 2a). Then, multi-stage hydraulic fracturing is performed to create pathways for fluid migration across the fault from the storage compartment to the receiving neighboring compartment. We assume that it is possible to create hydraulic fractures across the fault interface. As all the fractures in the synthetic model are identical and equidistant, the model can be reduced to a single slice with only one fracture (Fig. 2b).

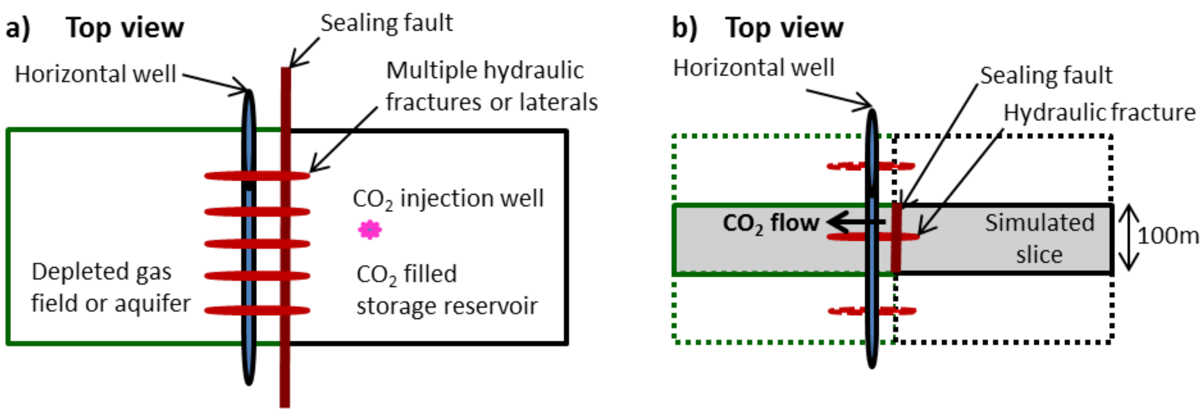

Fig. 2. (a) Schematic representation of the synthetic model with two adjacent reservoir compartments and a sealing fault intersected by multiple hydraulic fractures (top view). (b) Due to symmetry, the model can be reduced to a single slice with one fracture. The model is delineated by no flow boundaries (solid lines).

2.2 Synthetic model and simulation scenarios

The synthetic model setup is shown in Fig. 3. The model size is 100 m x 2000 m x 180 m with a grid block size of 10 m x 5 m x 5 m. The initial pressure in the storage compartment is 300 bar and 20 bar in the receiving (depleted) compartment, which are typical initial- and depleted pressures of gas reservoir in the Netherlands. The storage compartment has a dip of 5°, and the receiving compartment is horizontal. The juxtaposition of reservoir blocks across the fault is 30%. In the reservoir, two zones are identified: a 60m-thick top zone with good reservoir properties (permeability, k=100 mD, porosity, φ=0.12) and a 120m-thick bottom zone with poor reservoir properties (k=5 mD, φ=0.05). Vertical permeability is equal to horizontal permeability and the net-to-gross (NTG) ratio is 1. Both compartments are initialized with CO_2 and no gas-water contact is present. The storage capacity of the depleted compartment is about 0.5 million tonnes (Mt) of CO_2 for re-pressurization from the initial pressure of 20 bar to the pre-depletion pressure of 300 bar. For comparison, the estimated storage capacity of the real reservoir considered in the next section 2.3 is about 8 Mt, which implies that 16 synthetic symmetry elements (i.e. single slices) would be needed to store the same mass of CO_2. The hydraulic fracture is represented by a single column of 5m-wide grid blocks with a transmissibility of 1,000 mD*m (400 D * 2.5 mm). Thus, the permeability of the 5m-wide grid block representing the fracture is 200 mD.

The unintended CO_2 migration is defined at 10,000 sm^3/d and stops when pressure (P) is lower than 200 bar. The reason that the leakage stops due to a pressure reduction in the reservoir (at an arbitrary threshold of 200 bar) is, for example, the stress-sensitive fluid flow in a fracture or fracture network in the caprock leading to unwanted migration of CO_2 out of the storage complex. Because fracture permeability is sensitive to the effective stress and therefore also to the pore pressure changes, pressure reduction will cause closure of open fractures in the caprock making them non-conductive. The CO_2 leakage rate of 10,000 sm^3/d corresponds to a pressure reduction of 100 bar in 27 years (3.7 bar/yr). This is significantly higher than a pressure reduction of 0.03 to 0.9 bar/yr observed in the Bečej natural CO_2 field due to the leak caused by the uncontrolled migration of CO_2 through the caprock damaged by a blown-out well in 1968 [6]. The leakage rates used in our simulations are more in line with the rates used in [2]: 200-10,000 t/yr (~300-15,000 sm^3/d).

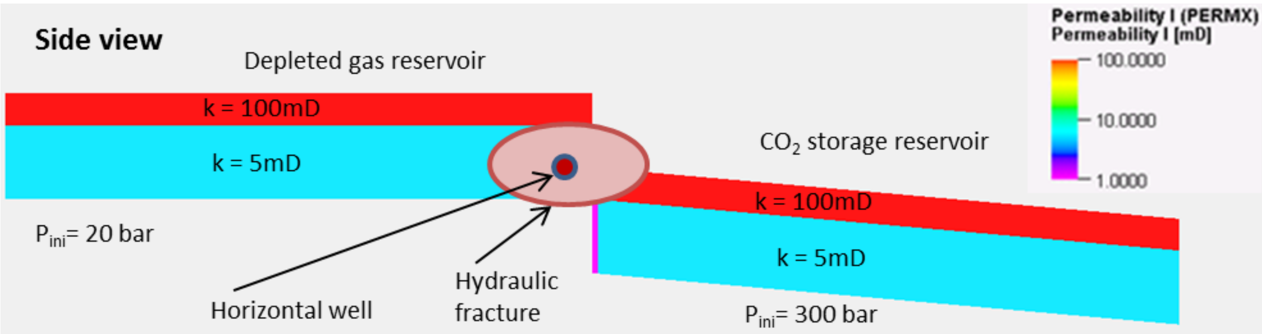

Fig. 3. Synthetic model with the base case parameters (side view).

A number of sensitivities was modelled to investigate the effect of important controlling factors on the efficiency of flow diversion (Table 1). In the geological scenarios 1-7 we varied the juxtaposition of the reservoir compartments across the fault (scenarios 1 and 2), the dip of the storage compartment (scenarios 3 and 4), the permeability of the lower part of the reservoirs (scenarios 5 and 6) and pore volume of the receiving compartment (scenario 7).

The sensitivity of the results with respect to the setup of the remediation is investigated in scenarios 8-12. The sensitivities considered variation in fracture permeability (scenarios 8 and 9) and the initial pressure in the receiving compartment (scenario 10).

In scenario 11, a pathway is created across the fault using a lateral well instead of a hydraulic fracture. In this case a radial well is considered [7]. In this type of well, small-diameter laterals are jetted from the main well bore using hydraulic jetting. For the radial wells, the same modelling approach is used and only one slice consisting of one radial well is modelled. The created well is 100 m long and has a diameter of 2 inch (5 cm). Pressure drop in the well is not simulated.

In scenario 12, the receiving compartment is not a depleted gas filed, but an aquifer. The pressure in both compartments is changed to be more representative of CO_2 storage in aquifers. The pressure in the aquifer is assumed to be hydrostatic; in the storage compartment, the pressure is 110% of hydrostatic. The unintended migration of CO_2 from the storage compartment stops when the pressure in the storage compartment is reduced to 105% of hydrostatic. It is assumed that the receiving compartment is very large to avoid rapid pressure build-up in that compartment.

Table 1. Simulation scenarios of the synthetic test case.

No.	Name	Description
Geological scenarios		
	Base case	The juxtaposition across the fault is 30% The dip of the storage compartment is 5° The permeability of the lower zone is 5 mD Fracture permeability is 400 D Initial pressure in the receiving compartment is 20 bar The receiving compartment is a depleted gas field
1	Juxtaposition = 10%	The juxtaposition across the fault is 10%
2	Juxtaposition = 50%	The juxtaposition across the fault is 50%
3	Dip = 0	The dip of the storage compartment is 0°
4	Dip = 10	The dip of the storage compartment is 10°
5	k = 0.1 mD	The permeability of the lower zone is 0.1 mD
6	k = 100 mD	The permeability of the lower zone is 100 mD
7	Pore volume x 2	Pore volume of the receiving compartment is multiplied by 2
Remediation scenarios		
8	Frac perm x 0.1	Fracture permeability is 40 D
9	Frac perm x 0.01	Fracture permeability is 4 D
10	P_INI = 80 bar	Initial pressure in the receiving compartment is 80 bar
11	P_INI = 80 bar + Well	Initial pressure in the receiving compartment is 80 bar and a lateral instead of a fracture is used as remediation
12	Aquifer	The receiving compartment is an aquifer instead of a depleted gas field

2.3 Real case

In the second part of the study, flow diversion is studied in a model representing the structure and the dynamics of a real reservoir, namely the depleted P18-4 gas field located in the North Sea about 20 km off the coast of Rotterdam. The model represents two adjacent, single-compartment gas fields formed in fault-bounded horst structures at a depth of about 3500 m. The southern compartment (P18-4) is considered for future CO_2 storage (Fig. 4a). The estimated storage capacity of the P18-4 reservoir is about 8 Mt of CO_2. The northern compartment (P15-9) also contained gas initially and has been depleted. The volume of the P15-9 reservoir is about 2.2 times larger than that of the P18-4 reservoir. A fault towards the north separates the P18-4 gas field from the adjacent P15-9 gas field (Fig. 4b). The reservoir thickness of about 200 m is approximately equal to the vertical fault throw; therefore, permeable reservoir facies are not juxtaposed across the fault. The fault appears to be sealing on a production time scale [8].

The P18 gas reservoirs belong to the Main Buntsandstein Subgroups. The oldest Volpriehausen Formation has low porosities (~5%) and permeabilities (~1 mD). The Volpriehausen is overlain by the Detfurth Formation, which is composed of the Lower and Upper Detfurth Sandstone Members. The youngest reservoir formation is the Hardegsen Formation. Parts of the Detfurth and the Hardegsen Formation (with porosities of 9-12% and permeabilities of 100-200 mD) contribute the most to gas production.

The model of the depleted P18-4 gas field used in previous studies for storage- and injectivity capacity estimations was extended and modified as described below to suit the analysis of potential remediation options. In the remainder of this paper, we will refer to the modified version of the P18-P15 model as the real case model. The structure, reservoir properties and gas properties for the real case model are taken from the P18-P15 gas fields.

2.4 Real case model and simulation scenarios

The thickness of the northern compartment is increased by adding an additional zone to the bottom of the original reservoir model. This zone, which is composed mostly of shale, is now juxtaposed against the upper, permeable part of the southern compartment (Fig. 4b). Permeability of the newly created zone is 0.01 mD in the horizontal direction and 0.0001 mD in the vertical direction. Porosity and NTG are 0.07 and 0.1, respectively. Similar to the synthetic case, the reservoir properties (permeability and porosity) in both reservoirs decrease with depth and the fault between the adjacent compartments is fully sealing (Fig. 4b).

The southern depleted compartment is filled with CO_2 to a pressure of approximately 350 bar over 5 years (from 1-1-2010 to 1-1-2015), which was the initial plan of the Rotterdam Capture and Storage Demonstration Project (ROAD) [8]. The northern compartment is depleted to approximately 20 bar and is still partially filled with the original hydrocarbon gas. In the simulation model, the northern depleted compartment was initialised at 20 bar without simulation of gas production, while the gas production from the southern compartment, and the subsequent CO_2 injection, were fully simulated.

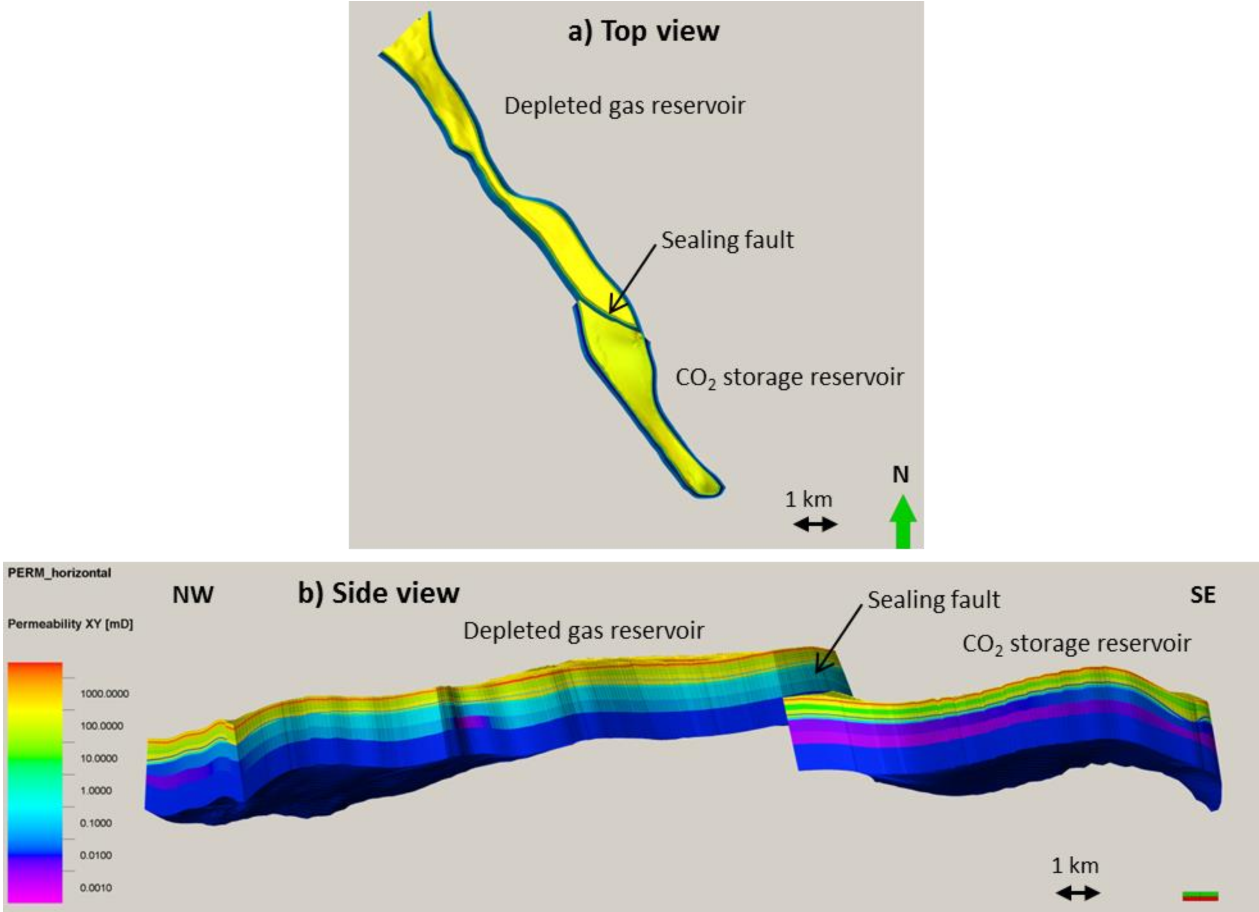

Fig. 4. (a) Top view and (b) side view of the real case model.

The remediation case setup for the real case is similar to the synthetic case: a horizontal well is drilled parallel to the fault in the low-permeability zone which is juxtaposed to the CO_2-filled reservoir and hydraulic fracturing is performed to create the pathways for fluid migration across the fault (Fig. 5). We assume that hydraulic fractures can propagate in the direction approximately perpendicular to the strike of the fault. In reality, hydraulic fracture will propagate in the direction of the present-day maximum stress, which is NW-SE in the Netherlands. Further, we assume that it is possible to create a few-hundred-meters-long hydraulic fracture using an appropriate treatment plan, as shown for the similar geological setting in [9]. We also assume that the hydraulic fractures, when propagating from a low permeable and more rigid layer towards a high permeable, less rigid layer will break the fault interface as shown in [10, 11]. The remediation starts directly after the end of the CO_2 injection period, on 1-1-2015.

In the base case scenario, we use two hydraulic fractures instead of multiple fractures to reduce the computational effort. The characteristics of these fractures (Table 2) are chosen to be optimal for remediation, but the same effects could be achieved using multiple fractures with lower permeabilities, as in the case of synthetic model (section 2.2). The fractures are not simulated explicitly in the reservoir model, but as non-neighboring connections. The permeability of the shale zone in which the fractures are created is 0.01 mD in the horizontal direction and 0.0001 mD in the vertical direction. NTG of the zone is 0.1 (this only affects the horizontal permeability).

Table 2. Characteristics of the hydraulic fractures in the base case scenario.

Property	Value
Half length	350 m
Total height	100 m
Permeability	1000 D
Width	0.025 m

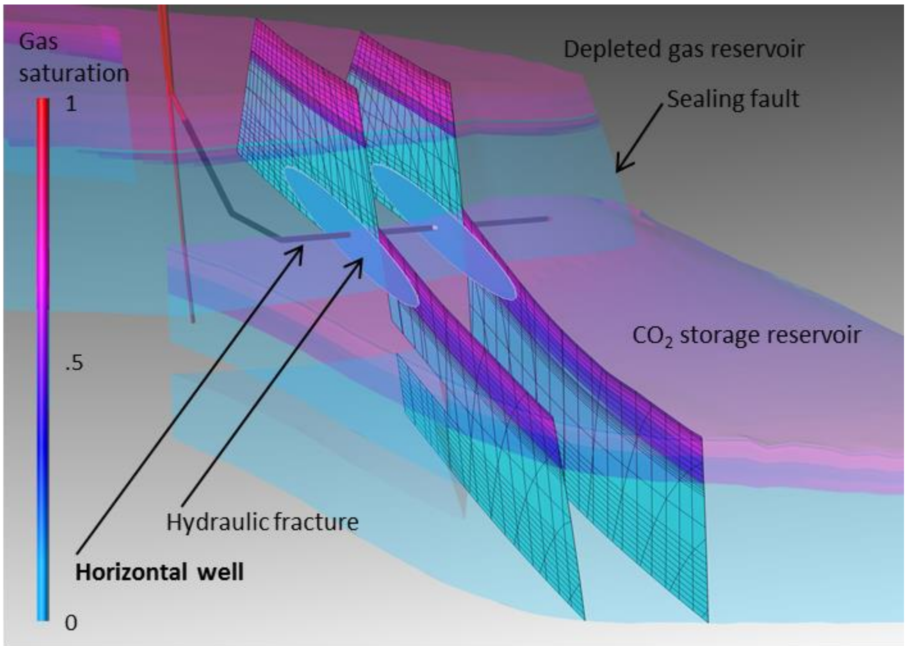

Fig. 5. Remediation with two fractures in the real case model.

In the sensitivity analysis we investigated the effect of different geological factors and remediation characteristics on the efficiency of flow diversion (Table 3). The focus of geological scenarios 1-4 is on the permeability of the receiving compartment, because this is the main limiting factor for efficient remediation. The sensitivity of the results with respect to the setup of the remediation is investigated in scenarios 5-8. All the remediation scenarios with fractures (scenarios 5-7) have been run with the increased permeability in the shale zone. In scenario 8, a deviated well instead of fractures is used to divert the CO_2 (Fig. 6). The well is perforated in both reservoir sections, and cross-flow in the well is allowed. The well diameter is 12 inches (0.30 m) and no tubing is assumed. Pressure drop in the well is not simulated.

Table 3. Simulation scenarios of the real field case.

No.	Name	Description
Geological scenarios		
1	2 fracs	Base case remediation with 2 fractures
2	2 fracs, kxy low zone x 100	Horizontal permeability in the shale zone multiplied by 100
3	2 fracs, kxyz low zone x 100	Horizontal and vertical permeability in the shale zone multiplied by 100
4	2 fracs, kxyz low zone x 1000	Horizontal and vertical permeability in the shale zone multiplied by 1000
Remediation scenarios		
5	3 fracs, kxyz low zone x 100	Remediation with 3 fractures Horizontal and vertical permeability in the shale zone multiplied by 100
6	High well, 2 fracs, kxyz low zone x 100	The horizontal well is located 40 m higher than in the base case Horizontal and vertical permeability in the shale zone multiplied by 100
7	High well, 2 fracs high, kxyz low zone x 100	The horizontal well is located 40 m higher than in the base case The two fractures are 200 m high and have a half-length of 250 m Horizontal and vertical permeability in the shale zone is multiplied by 100
8	Deviated well	Diversion of CO_2 is done by means of a deviated well (Fig. 6)

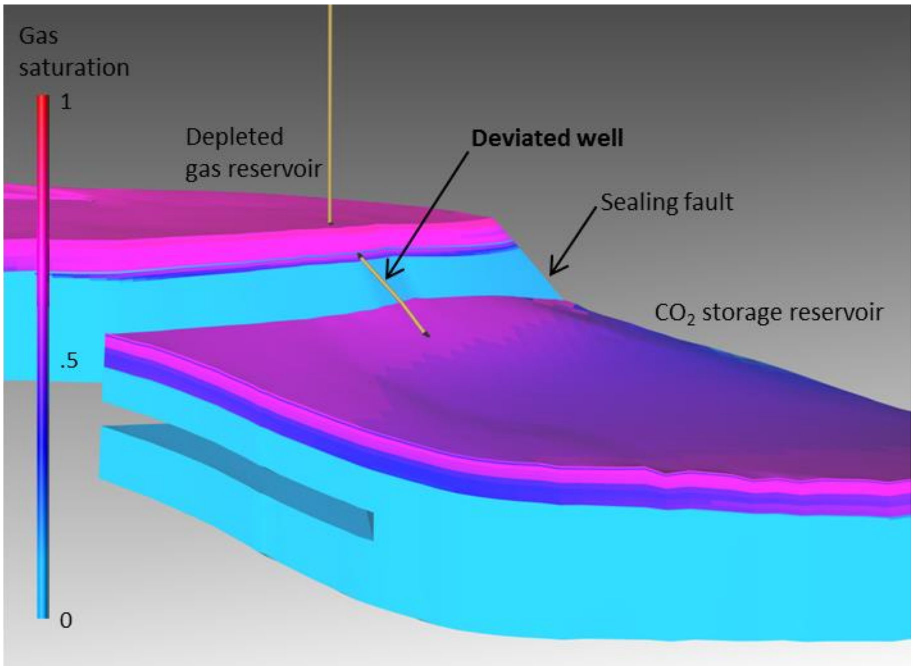

Fig. 6. Remediation with a deviated well used to divert the flow of CO_2 from the storage compartment to the neighboring compartment.

3 RESULTS

3.1 Synthetic case

Fig. 7 shows the evolution of leakage rate and pressure with time for the synthetic case without remediation. As expected, the pressure in the storage compartment decreases slowly due to continuous leakage. After approximately 27 years, the pressure has dropped to 200 bar, i.e. the assumed threshold at which the leak stops. In case of remediation with the simulation parameters corresponding to the base case scenario from Table 1, pressure in the storage compartment decreases much faster. After 40 days the pressure has dropped sufficiently to stop the leakage (Fig. 8). The pressure in the storage compartment and the receiving compartment equilibrate in about half a year.

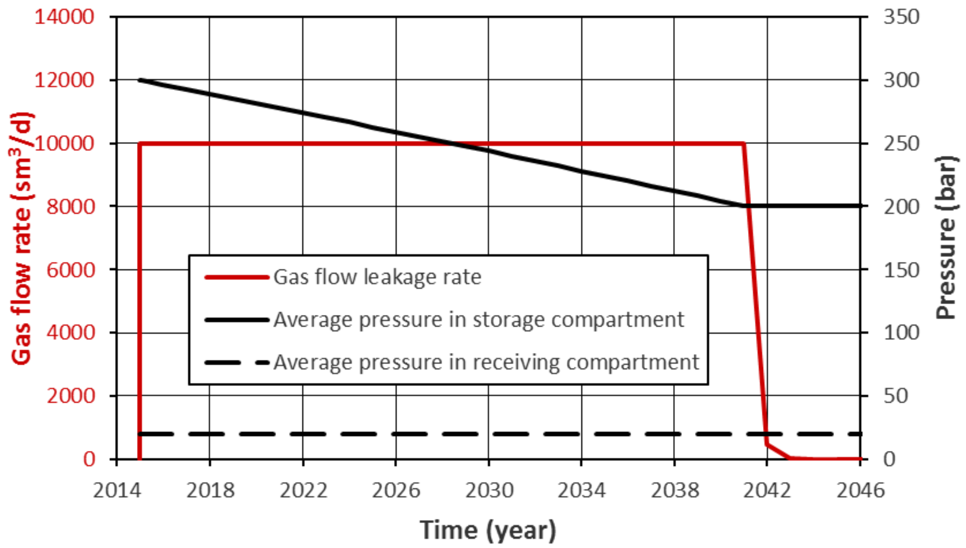

Fig. 7. Evolution of leakage rate and pressure in the synthetic model without remediation.

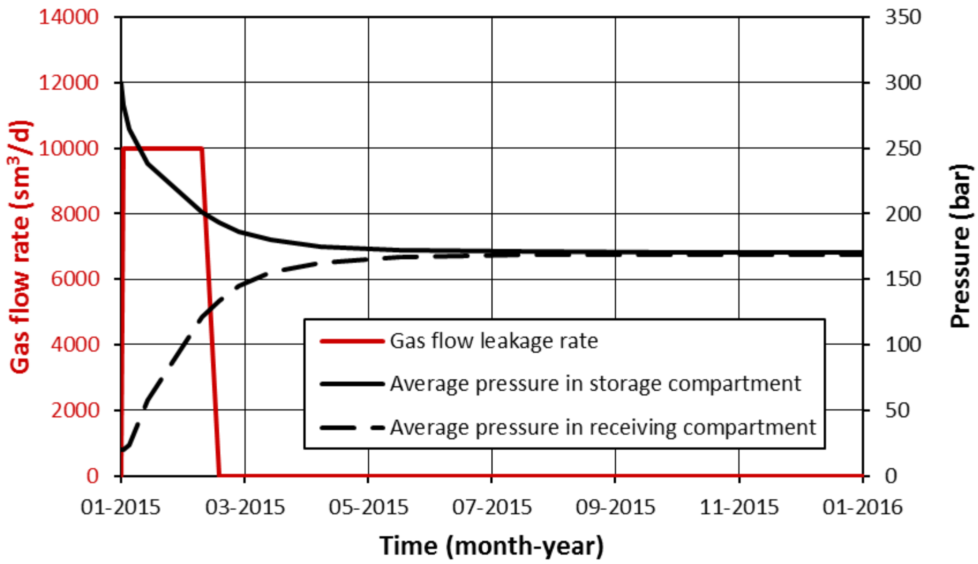

Fig. 8. Evolution of leakage rate and pressure in the synthetic model for the base case remediation scenario.

Fig. 9 compares the duration of remediation in the synthetic model for different scenarios. The time period until the unintended migration stops varies from 1 to 16 months for the range of input parameter values considered in the sensitivity study. For scenarios 1-10 with a hydraulic fracture, the duration of remediation depends primarily on the following key parameters: permeability of the adjacent reservoir sections connected by the created fracture (scenarios 5 and 6), the conductivity of the created fracture (scenarios 8 and 9) and the pressure difference between the two compartments (scenario 10). The higher the permeability of the connected reservoirs, the conductivity of hydraulic fractures and the pressure difference between the compartments, the shorter the duration of remediation.

The juxtaposition of more permeable parts of the reservoir across the fault is an important factor controlling possible connectivity of the reservoirs by a hydraulic fracture (scenarios 1 and 2). The longest duration of remediation that exceeds 500 days is obtained when a part of the storage reservoir with higher permeability is juxtaposed against a part of the receiving compartment with a very low permeability (~0.1 mD in scenario 5 instead of 5 mD in the base case). The sensitivity of the synthetic model to the considered variations in the inclination of the storage compartment appears to be low (scenarios 3 and 4).

In scenario 11, a 2-inch diameter lateral well is used to create a conduit between the two compartments. The duration of remediation with a lateral well of 130 days is almost twice as long compared to the similar scenario (10) with a fracture, where it amounts to 70 days. The time to stop leakage in scenario 11 is somewhat overestimated because the pressure drop in the well has not been taken into account in simulations. In a real case, a larger diameter for lateral wells may be feasible.

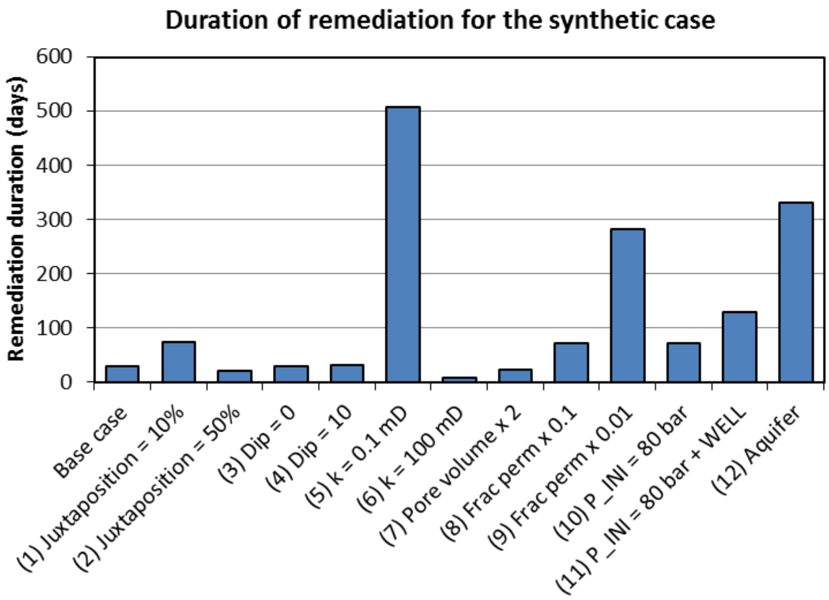

Fig. 9. Duration of remediation in the synthetic model for different scenarios (see Table 1 for scenario description).

For the aquifer scenario 12, it takes much longer (~330 days) for the unintended migration to stop. The pressure difference between the two compartments is here much smaller compared to other scenarios that assume a depleted receiving compartment. Also, the CO_2 moves slower into the receiving compartment as the effective permeability for gas is lower, due to the presence of water in the receiving compartment. After one year, lateral movement of water from the receiving aquifer compartment into the storage compartment is observed, due to the density difference between the CO_2 and brine (Fig. 10). As a consequence, more CO_2 will flow into the receiving compartment.

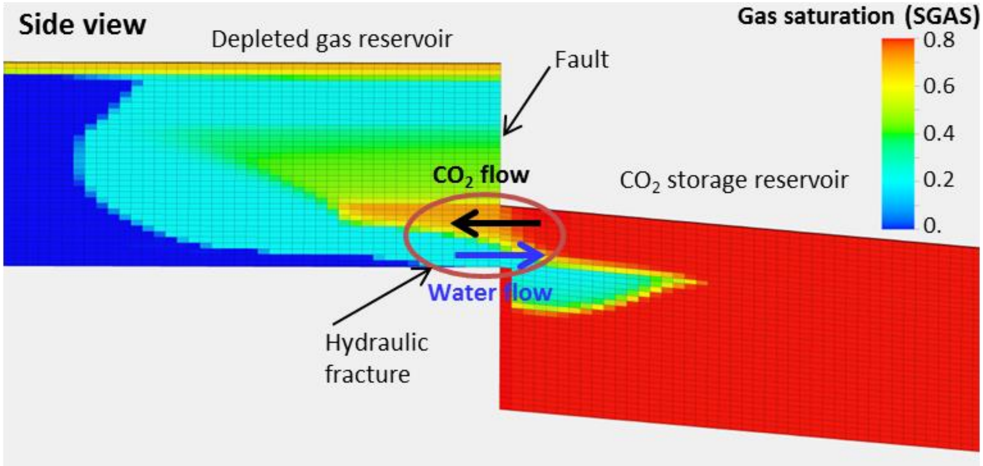

Fig. 10. Gas saturation in the synthetic model after 10 years of remediation in case when the receiving compartment is an aquifer (scenario 12 in Table 1).

3.2 Real case

The base case remediation scenario for the real case (scenario 1 in Table 3) has two hydraulic fractures, which connect the shale zone below the receiving reservoir with the storage reservoir (Fig. 4b). In Fig. 11, the results of the base case remediation scenario are compared to the case without remediation. The pressure drop in the storage compartment without remediation is due to pressure dissipation after termination of CO_2 injection. In the scenario with remediation, the amount of CO_2 diverted away from the storage compartment is very small: only 20 thousand tonnes of CO_2 in 5 years. The receiving compartment already contains some CO_2 because the original hydrocarbon gas also contained CO_2.The resulting additional pressure drop in the storage compartment at the injection well is less than 2 bar. The main reason for the poor effects of remediation is the low reservoir quality of the zone in the receiving compartment where the hydraulic fractures are created.

In the geological scenarios (Table 3), we investigated the effect of the horizontal and vertical permeabilities on the remediation efficiency by increasing the horizontal permeability only by a factor of 100 (scenario 2), the horizontal and vertical permeabilities by a factor of 100 (scenario 3), and the horizontal and vertical permeabilities by a factor of 1,000.

In Fig. 12 the pressure is shown over a period of 5 years for all geological scenarios. The impact of an increase in vertical permeability is much larger (a decline of 51 bar compared to no remediation) than in horizontal permeability (a decline of 9 bar compared to no remediation). Overall, the remediation using fractures is not very effective in this case: even when the permeability is increased by a factor of 1,000, the pressure drops only 92 bar over 5 years.

Weak effects of remediation in the real case compared to the synthetic case (with the remediation duration of 1 to 16 months) are largely due to a much smaller permeability and NTG in the real case. In the synthetic case, vertical permeability (*kz*) is equal to horizontal permeability (*kxy*) and NTG=1, while in the real case *kz* is 100 times smaller than *kxy* and NTG=0.1. This explains why the method is more effective in the synthetic case than in the real case.

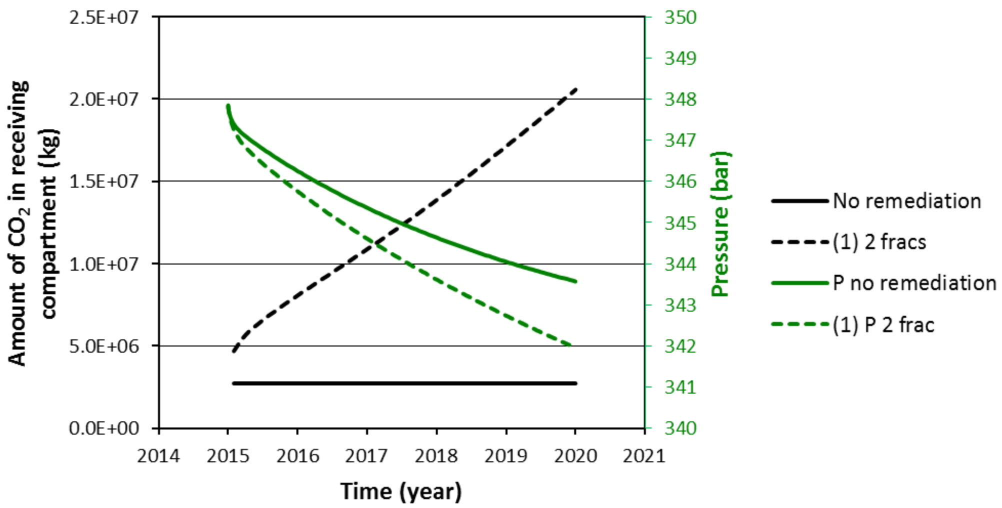

Fig. 11. The amount of CO_2 in the receiving compartment (black lines) and the pressure in the storage compartment (green lines) for the real case without remediation and the real case with remediation with 2 fractures (base case remediation scenario 1 in Table 3).

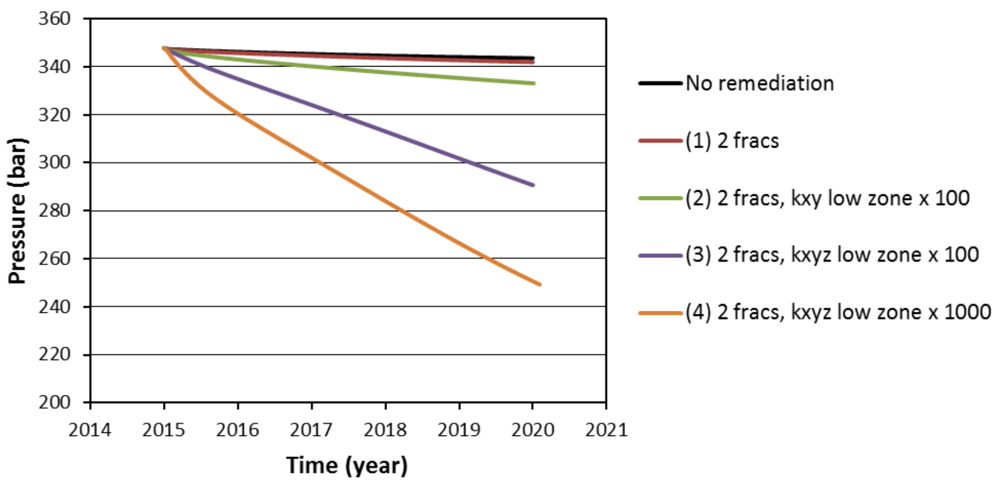

Fig. 12. Evolution of pressure in the storage compartment for different geological scenarios (the real case, scenarios 1-4 in Table 3).

The results for the remediation scenarios 5-8 are summarized in Fig. 13. As can be seen, the remediation using a well (scenario 8) is much more effective than the remediation using hydraulic fractures (scenarios 5-7). The reason is that the well connects the CO_2-storage reservoir with a highly permeable upper part of the receiving reservoir rather than with the shale layers below the reservoir, which is the case for hydraulic fractures. In less than a year, sufficient CO_2 has been diverted through a deviated well to equilibrate the pressure in the two compartments. In reality, it would take somewhat longer, because the rates in the first month are unrealistically high (> 15 million sm^3/d). However, even assuming that the rates in this first month are half of the calculated rates, diversion of the CO_2 and equilibration would be fast.

For the scenarios with hydraulic fractures, Fig. 13 shows that adding additional fractures only marginally increases the efficiency of remediation (scenario 5). The efficiency improves when the fractures are created to connect to the upper, more permeable part of the storage reservoir because the reservoir permeability decreases with depth (scenario 7 with “high fracs” gives better effects than scenario 6).

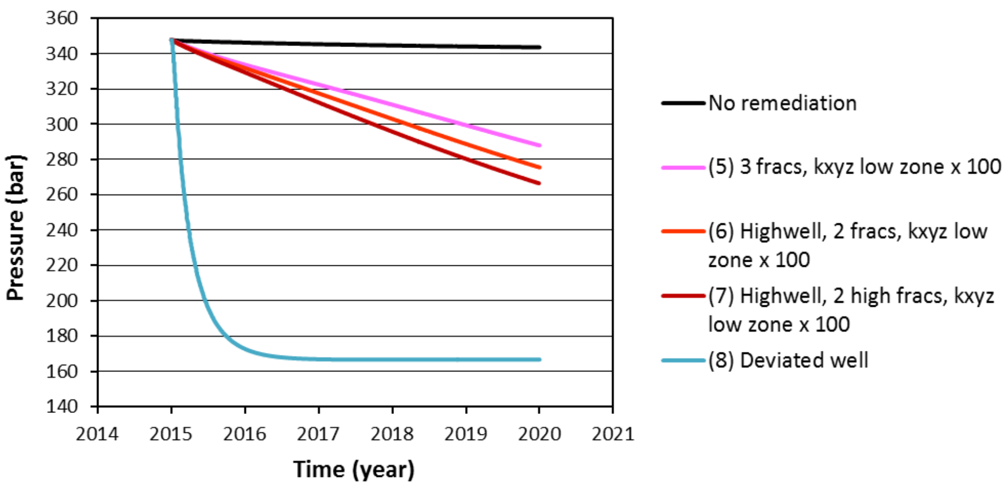

Fig. 13. Evolution of pressure in the storage compartment for different remediation scenarios (the real case, scenarios 5-8 in Table 3).

4 CONCLUSIONS

In the case of unwanted migration of CO_2 from the storage compartment, pressure relief in the storage formation can be achieved by diverting the CO_2 to unconnected parts of the reservoir, or to the adjacent reservoirs and aquifers. Flow diversion requires creating a pathway for fluid migration between the two originally unconnected reservoirs, which can be achieved by hydraulic fracturing across the fault or by drilling a well or laterals. This paper evaluates the effects of flow diversion as a remediation option through numerical simulations of an idealized synthetic case and a real field case from the North Sea, which was modified and then used to simulate hypothetical remediation scenarios.

From numerical modelling it is clear that the key factors controlling the efficiency of flow diversion are the conductivity of the created pathways between the two reservoirs, the pressure difference between the reservoirs and the permeability of the receiving reservoir. In the case of CO_2 diversion into an undepleted saline aquifer, the remediation is relatively slow due to the small pressure difference between the CO_2 storage compartment and the receiving aquifer.

The simulations of the real case showed that the diversion strategy needs to be optimized taking into account site-specific parameters and in-situ conditions. In particular, CO_2 needs to be diverted to a zone of the receiving compartment with sufficient permeability. For the conditions evaluated in the real case, the remediation using a well is much more effective than the remediation using hydraulic fractures.

ACKNOWLEDGEMENTS

The research leading to the results reported in this paper received funding from the European Community's Seventh Framework Programme (ENERGY.2013.5.2.1) under grant agreement n^o 608608 ("Mitigation and remediation of CO_2 leakage"). The project received additional funding from Statoil, ENGIE and Shell. The in-house simulator MoReS used in this study was kindly provided by Shell.

REFERENCES

[1] IEA Greenhouse Gas R&D Programme (IEA GHG), Remediation of Leakage from CO_2 Storage Reservoirs. 2007/11, September 2007.

[2] Esposito A, Benson SM. Optimization of remediation of possible leakage from geologic CO_2 storage reservoirs into groundwater aquifers. SPE Western regional meeting, Anaheim, California, 2010. SPE paper 133604.

[3] Rohmer JR, Le Guenan TLG, Réveillère AR, Vong CQV. Remediation of CO_2 leakage from deep saline aquifer storage based on reservoir and pollution engineering techniques. Second EAGE CO_2 Geological Storage Workshop, Berlin, Germany, 11-12 March 2010.

[4] Réveeillère, A, Rohmer J, Manceau J-C. Hydraulic barrier design and applicability for managing the risk of CO_2 leakage from deep saline aquifers. Int J Greenh Gas Con 2012;9:62-71.

[5] Manceau J-C, Hatzignatiou DG, Lary de L, Jensen DB, Réveillère A. Mitigation and remediation technologies and practices in case of undesired migration of CO2 from a geological storage unit – Current status. Int J Greenh Gas Con 2014;22:272-290.

[6] Karas D, Demić I, Kultysheva K, Antropov A, Blagojević M, Pluymaekers M, Orlić B. First field example of remediation of unwanted migration from a natural CO_2 reservoir: The Bečej Field, Serbia. The 8th Trondheim Conference on CO_2 Capture, Transport and Storage, Trondheim, Norway, June 16-18 2015.

[7] Ragab AMS. Improving well productivity in an Egyptian oil field using radial drilling technique. J Petrol Gas Eng 2013;4:103-117.

[8] Arts RJ, Vandeweijer VP, Hofstee C, Pluymaekers MPD, Loeve D, Kopp A, Plug WJ. The feasibility of CO_2 storage in the depleted P18-4 gas field offshore the Netherlands (the ROAD project). Int J Greenh Gas Con 2012;11S:S10-S20.

[9] Pizzocolo F, Hewson CW, Ter Heege JH. Polymer-gel remediation of CO_2 migration through faults and numerical simulations addressing feasibility of novel approaches. The 50th US Rock Mechanics / Geomechanics Symposium, Houston, Texas, USA, June 26-29 2016. ARMA paper 16-100.

[10] Warpinski NR, Teufel LW. Influence of geological discontinuities on hydraulic fracture propagation. J Petrol Technol 1987:209-220. SPE paper 13224.

[11] Wu H, Chudnovsky A, Dudley JW, Wong GK, 2004. A map of fracture behavior in the vicinity of an interface. Gulf Rocks 2004, Proceedings of the 6th North American Rock Mechanics Symposium, Houston, Texas, USA, June 5-9. ARMA/NARMS paper 04-620.