Available online at www.sciencedirect.com
ScienceDirect
Energy Procedia 63 (2014) 5707 – 5714
Energy Procedia

GHGT-12

Experimental and numerical investigations into CO_2 interactions with well infrastructure and its impact on long term well integrity

Amer Syed, Ji-Quan Shi, Sevket Durucan*, Anna Korre and Graham Nash

Department of Earth Science and Engineering, Royal School of Mines, Imperial College London, London, SW7 2BP, UK

Abstract

Research presented in this paper investigated the sealing behaviour of the microannulus at cement-casing interface under simulated subsurface reservoir pressure and temperature conditions and used the experimental findings to develop a methodology to assess the overall integrity of the wellbore region during CO_2 storage. A full scale wellbore experimental test set up was constructed for use under elevated pressure and temperature conditions encountered in typical CO_2 storage sites. Three test cases representing different reservoir depth, temperature and brine salinities were analysed through long term experiments with continuous flow of CO_2 through the microannulus. Relationships for the reduction in permeability of the microannulus with time were derived from the experimental data for use in reservoir simulations on a realistic reservoir model for all three scenarios to assess the impact of leakage from the wellbore casing and cement interface on integrity of CO_2 storage.

Peer-review under responsibility of the Organizing Committee of GHGT-12

Keywords: CO_2 storage; well integrity; casing cement interface; microannulus.

1. Introduction

The long term integrity of geologically stored CO_2 would depend on an impermeable caprock and absence of leakage pathways that could potentially result in the release of stored CO_2 into the atmosphere. Wellbore integrity is of paramount importance in this context as improperly executed well completions or failure of cement/casing is likely to trigger potential leakage of the stored CO_2 [1].

* Corresponding author. Tel.: +44-20-7594-7354; fax: +44-20-7594-7444.
E-mail address: s.durucan@imperial.ac.uk

Peer-review under responsibility of the Organizing Committee of GHGT-12
doi:10.1016/j.egypro.2014.11.603

Observations from oilfield operations indicate that the pressure reversals within the wellbore during production and injection of fluids could result in expansion and contraction of steel casing and impose cyclic displacement on the casing and the cement sheath, which may result in the formation of microannulus at the cement and casing interface [2]. Cement shrinkage can also result in circumferential crack propagation along these interfaces [3]

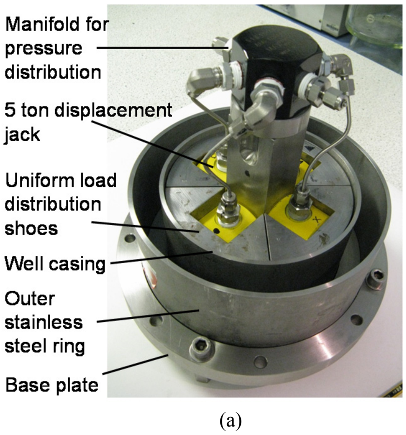
Early research has suggested that the casing-cement interface is more likely to be the primary path for potential CO_2 leakage as compared to the slow diffusion through the cement matrix [4, 5, 6]. The sealing characteristics of a conductive microannulus have first been studied for its structural integrity using a full-scale annular geometry by Boukhelifa *et al.* [7]. It was noted that the structural response of the cement to the mechanical deformation applied depends on the type of cement used. Carey *et al.* [8] reported the geochemical interpretation of cement-carbon steel interface for continuous flow of CO_2 under representative CO_2 geological storage conditions. Observations from scanning electron microscopy of the sample indicated evidence of chemical reactions between cement, steel, brine and CO_2.

The research reported here is aimed at describing the mechanisms in the near wellbore region with an emphasis on utilising the laboratory observations to assess wellbore integrity for CO_2 storage sites. Therefore, the main objective was to investigate the sealing behaviour of the rock-cement-casing interfaces under simulated downhole conditions subject to CO_2 fluxes. Experimental studies were carried out on a full scale wellbore model and the results obtained were used as input to numerical models of reservoirs with representative geological settings.

2. Design and construction of the wellbore model for laboratory experiments

A full scale laboratory test set up was designed to simulate the in-situ infrastructure and stress distribution around the CO_2 injection wellbore. The experimental set up was intended to address the following aspects: a) creation of a controlled microannulus between the wellbore casing and cement b) facilitate the application of stress on the casing in order to simulate subsurface stresses and control the width of the microannulus between cement and casing c) facilitate the flow of pore fluids through the microannulus between casing and cement d) simulate appropriate reservoir stresses acting on the cement. As shown in Fig.1, the wellbore test cell is essentially an assembly of a number of key components:

The central loading mechanism (CLM) consists of four case hardened shoes and can impart uniform radial load onto the well casing. The radial movement of the shoes is powered through the synchronised movement of four precision Enerpac jacks controlled hydraulically. Calibration routines were carried out to relate the hydraulic loading imparted by the jacks and the resulting displacement of the stainless steel casing (Fig. 1a).



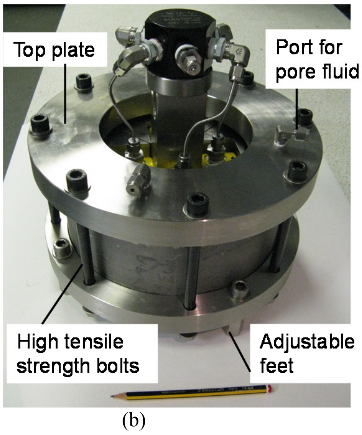


Fig. 1. Details of experimental set up for the wellbore cell: (a) central loading mechanism, casing, outer stainless steel cylinder and annular space for cement; (b) wellbore cell assembly.

The wellbore cell consists of two concentric *stainless steel cylinders* (Fig. 1a), with the inner one representing a well casing of 168.3 mm in diameter. The outer stainless steel cylinder is intended to simulate the stiffness provided by the reservoir rock to the displacement applied at the wellbore. Assuming an isotropic formation and plane strain conditions for the stress distribution around the injection wellbore, the relationship between the dimensions of the outer steel cylinder and the shear modulus of the formation it simulates has been obtained by equating the strain in the stainless steel ring and the rock [9]. For the current experimental programme, a cylinder of diameter 219.8 mm and thickness of 3.76 mm was chosen to represent relatively weak geological formation of shear modulus 3.4 GPa.

The wellbore cell is supported by 25.4 mm thick 316 stainless steel plates (Fig. 1b) to ensure the flow of fluids through the cement-steel casing interface. The stainless steel plates are equipped with ports for fluid flow and provision for pressure transducers. The bottom plate has four equally spaced adjustable legs along the circumference (Fig. 1b) to enable the cell to remain in horizontal position. The top and bottom plates are held in place using eight (8) high tensile bolts (Fig. 1b) which also ensure that the assembly remains gas tight.

Pressure is monitored at three locations using PDCR type pressure transducers supplied by Druck GE UK Ltd. The range of pressures that can be measured using these transducers is 0 - 13.78 MPa (0 - 2,000 psi). However, for high pressure and high temperature measurements UNIK 5000 specialist pressure transducers, supplied by GE Measurement and Control, capable of measuring pressures up to 41.36 MPa (6,000 psi) at 105 ^{o}C were used. In addition to the pressure transducers, a mass flow controller supplied by Agilent Technologies, USA, was used to control the volume of CO_2 injected into the wellbore cell.

A schematic of the experimental setup with the wellbore cell and ancillary equipment is shown in Fig. 2. An Ergotech hydraulic pump was used to control the displacement of the cement casing through the hydraulic jacks of the CLM. The test setup is enclosed in a laboratory oven, which acts both as temperature control and safety enclosure. The pore fluid is supplied either directly from a gas cylinder or from two ISCO syringe pumps, which ensure injection at a constant rate. Pure CO_2 or CO_2 saturated brine, as pore fluid, can be supplied thorough the syringe pump and accumulator at constant pressure or constant flow rate. The operational pore pressure and flow rates are applied to ensure that the flow remained laminar.

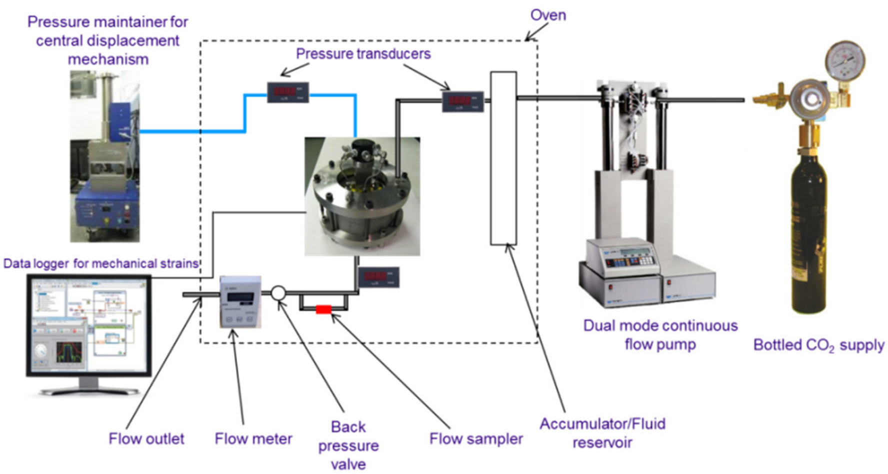


Fig. 2. Schematic representation of the experimental layout.

Before assembling the wellbore model, calibration routines were carried out to establish that both uniformity in radial loading applied by the CLM and uniformity in radial deformation of the stainless steel casing achieved.

In preparation for setting the cement between the two stainless steel cylinders, a pressure of 4 MPa was applied on the well casing to displace the stainless steel casing by 12 µm. In a clean laboratory vessel, Portland cement was mixed with deionised water to prepare API RP 10B Grade G cement mix. Keeping the well casing under stress, freshly prepared cement slurry was poured into the annulus between the stainless steel well casing and outer stainless steel cylinder. The cement was allowed to set for one day and the load was removed by retracting the well casing through depressurising the CLM and thus imposing tensile stress on the cement casing interface resulting in the creation of a microannulus. The cement was then cured for 28 days in water at ambient temperature.

3. Flow characteristics of microannulus at the cement casing interface

The sealing behaviour of microannulus to a flux of CO_2 flow at the cement casing interface was assessed for three sets of pressure and temperature conditions representing CO_2 storage in subsurface reservoirs (Table 1).

Table 1. Test conditions for three sets of experiments (salinities adapted from Michael *et al.* [9])

	Temperature (°C)	Salinity (% Vol)	Average reservoir pressure (MPa)	Flow rate (ml/min)	N_2 permeability (mD)	Brine permeability (mD)	
Scenario 1	40	3.5	10.0	70-100	320	290	Sleipner type*
Scenario 2	34	25.0	7.3	70-100	570	525	Ketzin type*
Scenario 3	92	12.5	35.0	300	410	385	North Sea deep reservoir type

* Here, the temperature and pressure values were taken as the main reference, rather than the exact depths of the injection wells at the field sites referred to.

After being cured for 28 days, the experimental wellbore cell was removed out of water and fitted with the auxiliary equipment and maintained at experimental temperature. Prior to CO_2 flow experiments, measurements were carried out to establish the flow characteristics of microannulus for non-reactive transport. Firstly, the permeability of the microannulus was measured using nitrogen as pore fluid. The experimental set up was then saturated with brine of appropriate salinity and continuous flow of brine at 1 ml/min was allowed through the microannulus at the cement-casing interface. The pressure drop across the wellbore cell was measured. The initial permeability of the microannulus (without any load on the CLM) was measured for all three experimental scenarios using nitrogen and brine as the pore fluid (Table 1).

As the test pressure and temperatures of scenarios 1 and 2 are nearly the same and test conditions vary only in salinity of the reservoir fluids, these two experiments were considered to quantify the effect of brine salinity and its impact on the sealing behaviour of the well casing and cement interface. Dry CO_2 was flowed through microannuli at a constant rate of 70-100ml/min, to simulate leakage of CO_2 from the well due to failure at the casing-cement interface. Initially, experiment started with CO_2 flow at 100 ml/min but has to be reduced to 70 ml/min at later stages to limit the increase in pore pressure. A pressure of 10 and 7 MPa, respectively, was applied to the central loading mechanism for the two scenarios to represent *in-situ* well pressure on the steel casing, which in turn controls the aperture of the microannuli. The flow rate was maintained so as to ensure the flow is capillary driven (capillary number ~ 10^{-12}) and that gravity effects are minimal.

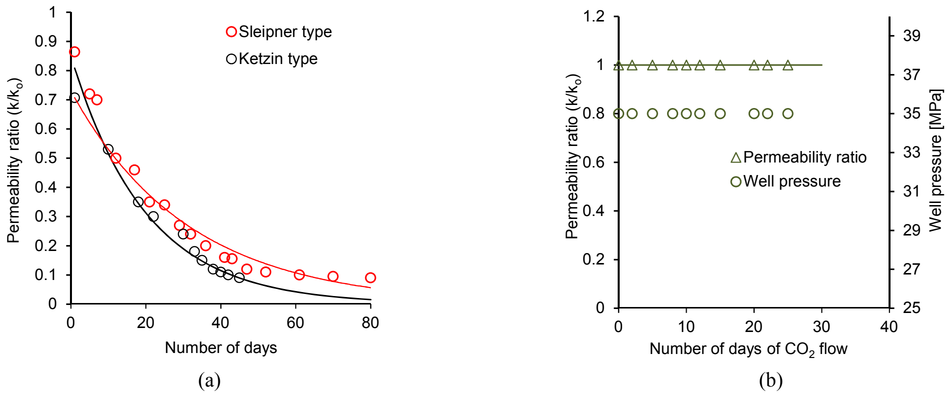


Fig. 3. Evolution of well permeability ratio over time for (a) Sleipner and Ketzin type and (b) the deep North Sea type wellbore during flow of CO_2 through the microannulus.

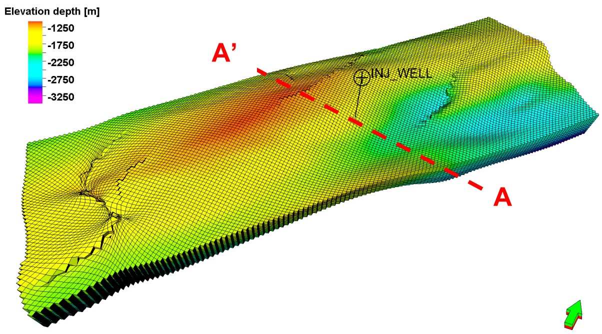
For the Sleipner type test conditions, a significant and noticeable change in permeability was observed within the first 60 days of the commencement of the experiments, after which the permeability remained nearly constant for the next 20 days of the experiment (Fig.3a). The reduction in permeability represents self-sealing behaviour of the cement under constant flux of CO_2. The reason for this decay is attributed to the reactive transport of CO_2 in the presence of brine and cement, resulting in the carbonation of cement and precipitation of calcite within the microannuli, acting as a barrier to flow of CO_2. Also, the layer formed by carbonation prevents CO_2 from flowing into the cement matrix as observed by Crow *et al* [6]. Analysing the flow rate over time, it was noted that the initial permeability of the Ketzin type scenario decreased faster than that for the Sleipner type scenario (Fig. 3a). This accelerated decrease in permeability was due to the accelerated carbonation rates as a result of higher salinity of the brine. The rate of reduction in permeability was further increased by the deposition of salt from the brine, an observation that was visually confirmed when the experimental test rig was dismantled.

In the case of deep North Sea type reservoir conditions, the CO_2 flow-through experiments were carried out at high temperature and CLM pressure at a constant CO_2 flow rate of 300 ml/min. The pressure on CLM was set at 35 MPa and the experimental set up was maintained at 92 ^oC. No change in permeability was observed with CO_2 flow, a possible reason being that the cement is dehydrated at such a high temperature and, hence, carbonation reactions are minimal or absent (Fig.3b).

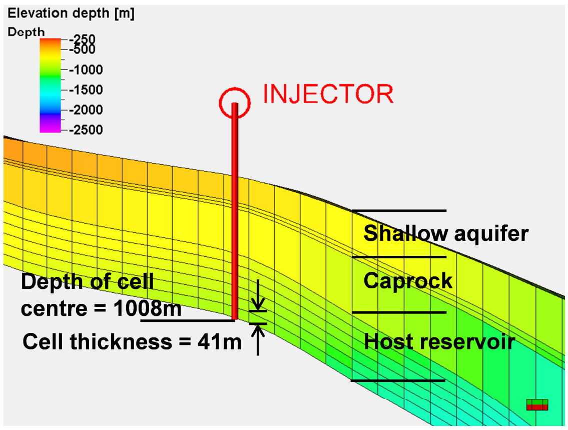
4. Numerical simulations to evaluate long term processes at wellbore

The objective of numerical modelling was to simulate the long term processes at the wellbore to evaluate the potential for leakage through and/or along the wellbore during the post-closure period. Near wellbore processes such as self-sealing behaviour of the cement casing interface and convective diffusion of CO_2 into the reservoir brine were incorporated in the model.

In accordance with the reservoir setting tested experimentally in the laboratory, numerical simulations for subsurface CO_2 behaviour were carried out for identical settings (pressure, temperature and brine salinity) on a realistic reservoir stratigraphy and reservoir properties representative of the sites modelled [5, 11]. The geometry of the model was taken as a template and the earth model was created by changing the model depth to respective reference depths. Petrel® was used to create the earth model and Eclipse 300 was used for all reservoir simulations. The extent of the field in two mutually perpendicular axes is approximately 32 × 13 km. The reservoir model consisted of three zones: A host reservoir with an impermeable caprock and an overlying shallow aquifer. Fig. 4 depicts the horizons for Sleipner type reservoir setting. The average thicknesses of the host reservoir, caprock and shallow aquifer were 235 m, 262 m and 209 m respectively. The grid dimensions in the 3D model were 200 m × 200 m. The shallow aquifer was further divided into three layers whose thicknesses were set a ratio of 8:1:1 so as to enable observation of CO_2 saturations at various depths within the shallow aquifer.



(a)



(b)

Fig. 4. (a) The 3D grid model for the Sleipner type reservoir and the location of CO_2 injection well; (b) Cross section along AA' showing the injection well (2× vertical exaggeration).

In the near wellbore region, grid refinement was implemented at three levels as shown in Table 2. The wellbore block in coarse grid is divided into 10,000 grid blocks, each with a dimension 2 × 2 m. In the second level of grid refinement, 10 grid blocks on either side of the original grid blocks were divided into 100 blocks, each with dimensions of 20 × 20 m. For the third level of grid refinement 1,000 m of a domain on either sides of the well from 1,100 m was divided into 4 blocks of dimensions 100 ×100 m. Fig. 5 presents the near wellbore region and localised grid refinement in this region. This local grid refinement was carried out for the reservoir models generated for the scenarios 1-3.

Table 2. Grid refinement details in near wellbore region.

	Distance from injection well (m)	Net spatial width (m)	Size of grid block (m)
Level 1 Well block	100 m on either side	200	2
Level 2	1,100 m to 2,100 m on either side	1,000 m and 1,000 m	20
Level 3	2,100 m to 3,100 m on either side	1,000 m and 1,000 m	100

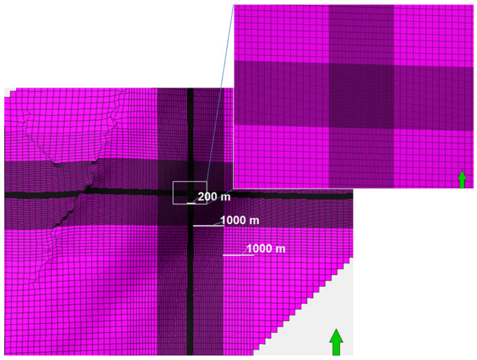


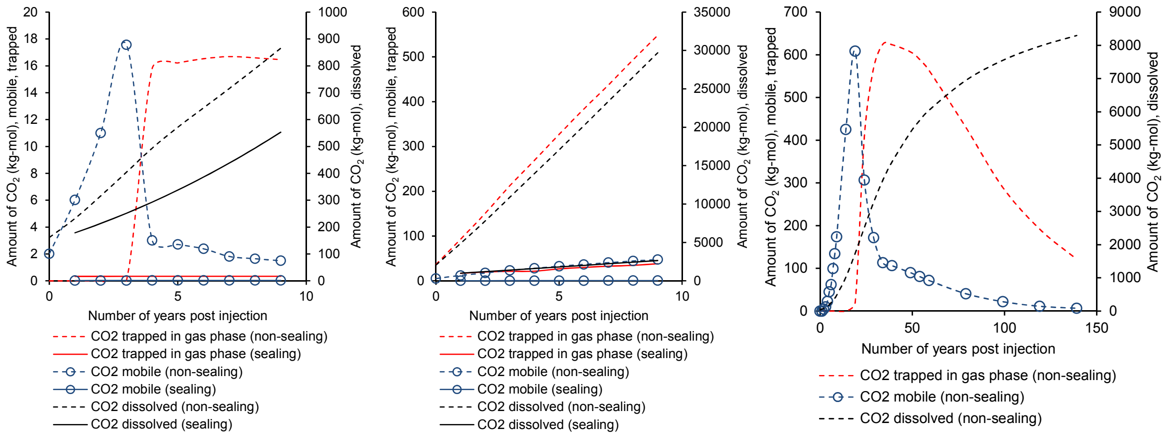
Figure 5. Local grid refinement for flow simulation.

The relative permeability characteristics for CO_2 brine systems for both drainage and imbibition for Sleipner and North Sea type were adapted from Viking sandstone data reported by Bennion and Bachu [5] and for the Ketzin type reservoir model adapted from Kempka and Kuhn [11].

During the simulations, CO_2 was injected at a rate of 1 Mt/year for 10 years; wellbore leakage of CO_2 was assumed to occur at the start of post-injection period. Wellbore leakage was simulated by introducing a permeable grid block (containing the injection well) in the caprock through its thickness, assigned with a permeability value same as that of the microannulus measured in the laboratory. The self-sealing behaviour was implemented by changing permeability of the grid blocks with time, following the relationship derived from the experimental studies (Figs. 3a and 3b).

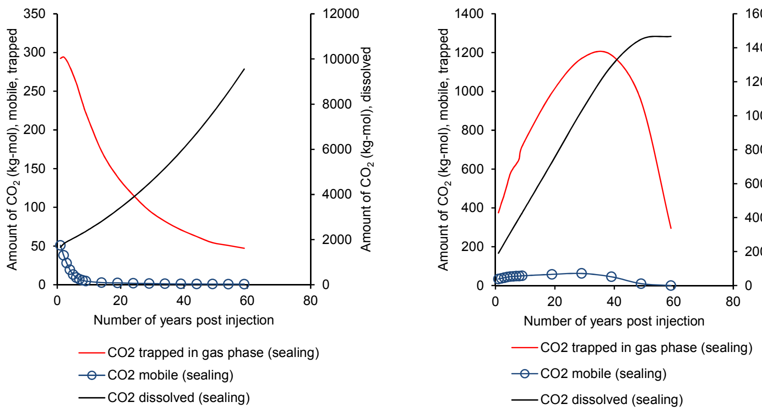
The amount of CO_2 leaked into the shallow aquifer over a period of 10 years with and without self-sealing effects of the microannulus for Sleipner and Ketzin type of reservoir settings is shown in Figs. 6a and 6b. It can be seen that the amount of CO_2 in all phases (dissolved, trapped and mobile), particularly the last two, within the shallow aquifer would be significantly reduced with the implementation of the sealing effects in the model, illustrating the positive impact of self-sealing behaviour of the microannulus in limiting the leakage of CO_2. Moreover a subsequent decrease in the amount of mobile CO_2 for the scenario without the self-sealing effects indicates diminished risk of CO_2 transport further from its source. The experimental results for deep North Sea reservoir type setting indicated the absence of self-sealing behaviour. Numerical simulations carried out for this reservoir setting (Fig. 6c) indicate a sharp increase in the mobile CO_2 during the early stages, suggesting that the wellbore needs to be remediated to contain the leakage. However, the mobile CO_2 leaked into the shallow reservoir would become largely immobile after around 100 years.

Simulations carried out for further 50 years (60 years after the CO_2 injection is terminated) for both Ketzin and Sleipner type reservoirs, without self-sealing effects, indicate that the mobile CO_2 within the shallow aquifer is progressively reduced to zero, within 20 years post injection for Sleipner type reservoir and 60 years for Ketzin type reservoir. (Figs. 7a and 7b). The increase in the amount of dissolved CO_2 indicates that the amount of CO_2 leaked is safely dissolved in the brine in the shallow aquifer.



(a) (b) (c)

Fig. 6. Mobile, trapped and dissolved CO_2 in the shallow aquifer for sealing and non-sealing cases, (a) Sleipner type (permeability of leakage pathway = 6 mD); (b) Ketzin type reservoir settings (permeability of leakage pathway = 10 mD) and (c) deep North Sea reservoir type (permeability of leakage pathway = 2.5 mD).



(a) (b)

Fig. 7. Mobile, trapped and dissolved CO_2 in the shallow aquifer of a) Sleipner type and b) Ketzin type reservoirs 60 years after injection is terminated.

5. Conclusions

Experimental research into the sealing behaviour of the wellbore casing cement interface and the microannulus formed has suggested that self-sealing behaviour of cement under constant flux of CO_2 would reduce permeability progressively under shallow reservoir conditions. This self-sealing behaviour during the reactive transport of CO_2 is attributed to the carbonation reactions between cement, brine and CO_2. However, this self-sealing behaviour was absent at elevated temperatures (T = 92° C) which may be due to complete dehydration of the cement.

Numerical modelling studies were carried out on three distinct and realistic geological reservoir settings with the assumption that microannulus at the well casing cement interface results in a permeable pathway through which CO_2 injected into a host formation leaks into a shallow aquifer. Results from the numerical simulations indicated that the amount of CO_2 in all phases (dissolved, trapped and mobile) within the shallow aquifer would be significantly reduced with the implementation of the sealing effects in the model.. Furthermore reservoir simulations also indicated that, at the temperatures and pressures tested (T = 34 - 40 ^oC and P = 8 - 10 MPa) the CO_2 leaked into the shallow aquifer would be fully dissolved or trapped within 60 years after the end of injection for the cases considered.

This research suggests that, leakage from the microannulus between the well casing and cement of an injection well in a relatively shallow formation may not pose a risk to CO_2 containment in the long-term, as the self-sealing mechanism may eventually stop the leakage. But, if such leakage is to be observed in deep, high temperature and high pressure reservoirs, a contingency plan for remediation of the leakage must be put in place to secure the containment of CO_2.

Acknowledgements

Research reported in this paper was conducted with funding from the European Commission FP7 project CO2CARE, Grant Agreement No: 256625, and also co-financed by an industrial consortium consisting of Statoil, Shell, TOTAL, RWE, Vattenfall, and Veolia. The Petrel and ECLIPSE 300 software used in this study is kindly provided by Schlumberger.

References

[1] Metz B, Davidson O, de Conincj H, Loos M, Meyer L (Ed.). IPCC special report on Carbon dioxide Capture and Storage, Cambridge University Press; 2005.
[2] Thiercelin MJ, Dargaud B, Baret JF, Rodriquez WJ. Cement design based on cement mechanical response. SPE Drilling and Completion 1998; 266-73.
[3] Dusseault MB, Gray MN, Nawrocki PA. Why oilwells leak: Cement behaviour and long-term consequences. Proceedings of the International Oil and Gas Conference and Exhibition in China, 7-10 November, Beijing, China 2000; SPE 64733-M.
[4] Carey JW, Wigand M, Chipera SJ, WoldeGabriel G, Pawar R, Lichtner PC, Wehner SC, Raines MA. Analysis and performance of oil well cement with 30 years of CO_2 exposure from the SACROC Unit, West Texas, USA. International Journal of Greenhouse Gas Control 2006; 1: 75-85.
[5] Bachu S, Bennion DB. Experimental assessment of brine and/or CO_2 leakage through well cements at reservoir conditions. International Journal of Greenhouse Gas Control 2009; 3:494-501.
[6] Crow W, Williams DB, Carey JW, Celia M, Gasda S. Wellbore integrity analysis of a natural CO_2 producer. Energy Procedia 2009; 1: 3561-69.
[7] Boukhelifa L, Moroni N, James SG, Roy-Delage SL, Thiercelin MJ, Lemaire G. Evaluation of cement systems for oil- and gas-well zonal isolation in a full-scale annular geometry. IADC/SPE Drilling Conference, Dallas, Texas, 2004. SPE 87195.
[8] Carey JW, Svec R, Grigg R, Zhang J, Crow W. Experimental investigation of wellbore integrity and CO_2 brine flow along the casing cement microannulus. International Journal of Greenhouse Gas Control 2010; 4: 272-82.
[9] Baumgarte C, Thiercelin M, Klaus D. Case studies of expanding cement to prevent microannulus formation. SPE Annual Technical Conference and Exhibition, Houston, Texas, USA.1999. SPE 56535-MS.
[10] Michael K, Golab A, Shulakova V, Ennis-King J, Allinson G, Sharm, S, Aiken T. Geological storage of CO_2 in saline aquifers – A review of the experience from existing storage operations, International Journal of Greenhouse Gas Control 2010; 4: 659-667.
[11] Kempka T, Kühn M. Numerical simulations of CO_2 arrival times and reservoir pressure coincide with observations from the Ketzin pilot site, Germany. Environmental Earth Sciences 2013; 1-11.