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Energy Procedia 4 (2011) 3379–3385
Energy Procedia
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GHGT-10

In Salah CO_2 storage JIP: Carbon dioxide plume extension around KB-502 well - New insights into reservoir behaviour at the In Salah storage site

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Abstract

Surface uplift has been detected over all three of the In Salah CO_2 injection wells with corresponding subsidence also observed over the gas production area. In particular, it has been noted that the surface uplift over KB-502 displays two distinctive lobes aligned along the direction of the maximum principal stress in the region, originating from the heel and the toe of the horizontal wellbore respectively. As part of the work programme within the EU funded CO2ReMoVe project, Imperial College has carried out short-term reservoir simulations of CO_2 injection into the aquifer portion of the C10.2 sandstone formation, initially focusing on history match of injection well pressure at KB-502 and CO_2 breakthrough at the nearby KB-5 observation well (now fully decommissioned) along the heel-side lobe. In view of the satellite monitoring data of the surface deformation at the Krechba gas field and published findings of the inversion modelling work, the reservoir model is further improved to account for the pressure distribution inferred from the surface uplift data, as well as the reservoir-based field data. Specifically, the permeability pattern inverted from the surface uplift data has been used to further constrain the reservoir model to improve prediction of the CO_2 plume migration around KB-502, so that it is consistent with the surface monitoring data, as well as reservoir-based observations (injection pressures and CO_2 breakthrough at KB-5).

Keywords: In Salah CO_2 storage; InSAR surface monitoring; reservoir simulation

1. Introduction

Since the start of In Salah CO_2 storage project in 2004, around one million tonnes of CO_2 per year have been separated from the produced gas streams in the In Salah gas fields and about 70% of this re-injected back to the subsurface into the aquifer-leg of the Carboniferous sandstone reservoir. The main CO_2 storage aquifer (C10.2) is approximately 20-25 metres thick at about 1,880 m below the surface. The C10.2 formation is overlain by a tight sandstone and siltstone formation (C10.3) of about 20 m in thickness, which is in turned overlain by a thick formation of Carboniferous Viséan mudstone interbedded with thin dolomite and siltstone layers, Figure 1a [1]. The C10 formation, together with the lower cap rock (C20.1 – C20.3), form what is called the CO_2 storage complex at Krechba. Figure 1b shows the Krechba field layout [2]. The three CO_2 injection wells (KB-501, KB-502 and KB-503), as well as the gas production wells, are drilled across principal open fracture set (maximum horizontal stress direction).

Shortly after the start of CO_2 injection at Krechba, surface uplift was detected using satellite-based interferometry (InSAR) technology over all three horizontal CO_2 injection wells with corresponding subsidence also observed over the gas production area [3, 4]. CO_2 injection into a formation at ~1,900 m over a period of over four years has apparently caused a surface uplift up to ~2cm over the injection wells. In particular, it has been noted that the surface uplift over KB-502 displays two distinctive lobes aligned along the direction of the maximum principal stress in the region, originating from the heel and the toe of the horizontal wellbore respectively, Figure 2 [5].

The observed surface uplift/subsidence is primarily due to the expansion/compaction of the reservoir formation caused by the CO_2 injection and gas production. Therefore the surface deformation measurements provide useful information on the subsurface

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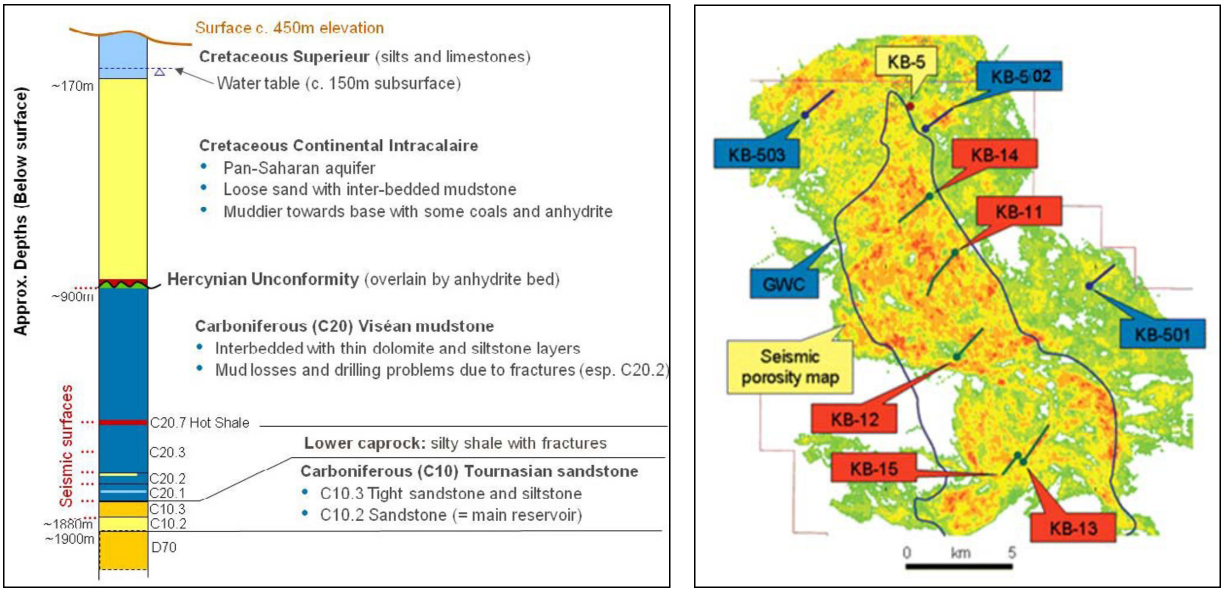
doi:10.1016/j.egypro.2011.02.260

CO_2 flow behaviour and can be used to assess whether the induced volume changes are confined to the target storage complex or not. Rutqvist et al. [6] reported a coupled fluid flow and geomechanical modelling study of CO_2 injection into a single well under In Salah storage conditions, using the available rock mechanical properties of the Krechba reservoir and overburden formations. They reported that the C10.2 reservoir layer itself could not generate the level of surface uplift (~2 cm) observed over KB-501. They argued that the surface uplift would be increased (from ~1.2cm to ~2 cm) by allowing upwards pressure propagation into the overlying tight sandstone layer (C10.3) and the lower caprock (C20.1), with increased pressure up to 50m above the top of C10.2.



(a) (b)

Figure 1. (a) Krechba stratigraphic summary [1]; (b) Krechba field layout showing the locations of the three CO_2 injection wells (KB501, KB502 and KB503) and the five production wells (KB-11, KB-12, KB-13, KB-14 and KB-15) [2].

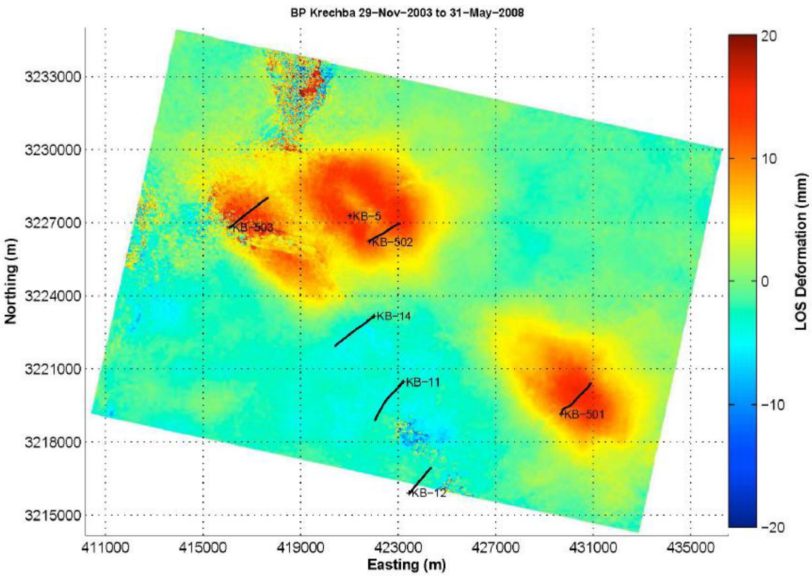


Figure 2. Surface deformation detected over the CO_2 injection and production wells at Krechba using PSInSAR technique [5].

Vasco et al. [3] reported an inverse modelling effort to estimate the volume and associated pressure changes at the injection level (C10.2) around KB-502. Using a simplified reservoir model of the storage aquifer, which ignored formation topography at the injection level and also assumed homogeneous reservoir properties, Vasco et al. found that a continuous pressure distribution showing two lobes could not be produced by limiting pressure increase in the 20 m thick formation alone, but that a greater pressurised volume was required, extending between 100 m and 200 m above C10.2. From the inferred pressure distribution, Vasco et al. were able to estimate the permeability distribution, normalised against the model base reservoir permeability, which features two distinctive lobes with elevated permeabilities of up to 300 times as the model base permeability.

As part of the EU 6th Framework project CO2ReMoVe, co-funded by Industry partners, short-term reservoir simulations have been carried out at Imperial College, aiming to gain a better understanding of the reservoir behaviour at Krechba during CO_2 injection. This has been an iterative process, with the reservoir model being updated as and when new information/data became available. In this paper, we report the progress made up to the submission of the abstract in December 2009, where we have incorporated the findings from the inverse modelling work by Vasco et al. [3] and the available reservoir-based field injection data, in the short-term reservoir simulation and history matching of CO_2 injection at Krechba.

2. Reservoir simulation and history matching at Krechba

The reservoir/overburden models used at Imperial College are based upon the static (complex) earth model made available to CO_2ReMove project team by the Joint Industry Project (JIP- BP, Statoil, Sonatrach). The static earth model of the Krechba gas field has 6 stratigraphical units, which are subdivided into 135 layers, 3 of which are in the C10.2 reservoir sandstone. The grid blocks have dimensions of roughly 400 m by 400 m.

There is evidence from well image logs, mud loss during drilling and core inspection which indicate that both KB-14 (a production well) and Kb-502 (a CO_2 injection well) have encountered fractures, at different vertical intervals [4]. A dual-permeability reservoir model was subsequently constructed, incorporating the fracture characterisation work by Schlumberger in the reservoir model. In implementing the fracture permeability in the dual-permeability reservoir model, two scenarios were considered regarding the extent of fractures in the reservoir during the simulations: 1) a localised fracture network around KB-502, based upon the FMI image interpretation by Schlumberger; and 2) a reservoir-wide fracture network, assuming that the fractures are distributed across the whole reservoir. The fracture permeabilities generated ranged from 150 to 350 mD. This compares with matrix permeabilities, mostly within the range 0-10 mD, in the C10.2 reservoir in the Statoil earth model.

Reservoir simulation has been carried out to history match the reservoir-based injection data: first the injection wells pressure and then the observed CO_2 breakthrough at the KB-5 observation well, about 1.3 km to the NW of injection well KB-502. The simulation effort was initially focused on the C10.2 sandstone reservoir, assuming that there is no pressure communication between C10.2 and the overlying C10.3 formation. This was achieved by assigning a nominal permeability value of $1e^{-10}$ mD to the C10.3 tight sandstone layer. Thus only the C10.2 Carboniferous formation was considered as active in the reservoir/overburden model.

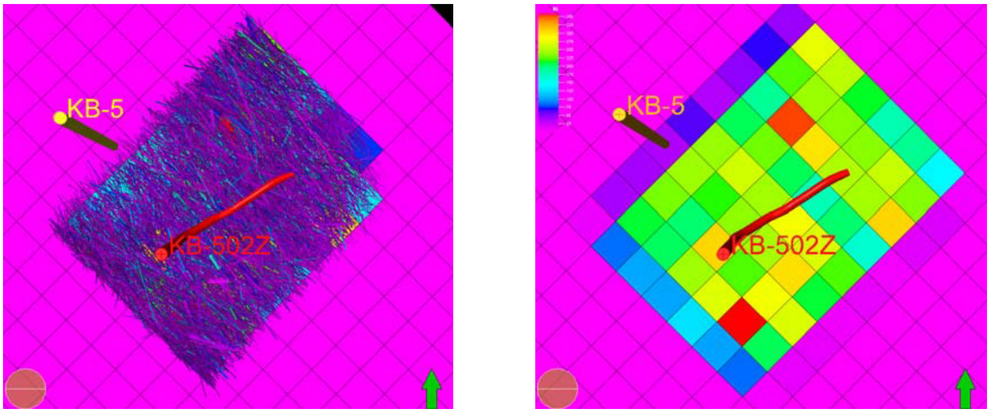
The results of this history matching effort are presented in this section. The published satellite surface deformation data, and especially the findings of the inversion modelling by Vasco et al. [3], enabled us to adopt an integrated simulation approach, which seeks to incorporate the permeability pattern inverted from the surface uplift data into the reservoir simulation. The simulation results of the new approach will be presented in the next section.

2.1. History matching of field injection pressure

The bottomhole pressures (BHP) of the injection wells were not available for history matching. However, the wellhead pressures (WHP) at the three injection wells and also production wells are known. In the absence of BHP measurements, the likely range of the BHP was initially estimated by adding the WHP data with the hydrostatic pressure of a ~1,900 m CO_2 column, the latter was assumed to lie between 0.4 and 0.7 of that of a static water column. Later on a more accurate estimation made by Schlumberger, taking into account the temporal variations in the CO_2 injection rate and temperature changes along the injection wellbore, was used in history matching.

CO_2 injection at Krechba (KB-501 and KB-503) started in August 2004. Injection at KB-502 followed 8 months later (April 2005). Reservoir simulations of CO_2 injection, using the field hydrocarbon production and CO_2 injection rates as input, were initially run up to December 2007. To start with, a single-permeability reservoir/overburden model (with only the matrix permeability) was used. It was found that the field injection rates at all three wells could not be sustained with the matrix permeability given in the earth model during the injection period, as the simulated BHP were much higher than the upper bound of BHP estimates. In particular, the simulated BHP at KB-502 reached ~650 bars, more than double the upper bound of the estimated field WHP pressure. Therefore, the simulation results supported the field observations that the reservoir is likely to be fractured around KB-502 and, these fractures are contributing to the overall well injectivity.

The implementation of a local fracture network around KB-502 in the reservoir model (Figure 3) resulted in a BHP curve well within the estimated range of the field pressure data (not shown here). However, the simulation results with the reservoir-wide dual-permeability model indicated that the local fracture network derived from the FMI image at KB-502 could not be simply extended to the whole reservoir. In an attempt to match the field pressure at the two other injection wells (KB-501 and KB-503), it was found that the fracture permeability needs to be reduced by roughly two orders of magnitude to bring the model BHP to within the upper bound of the field data. In other words, the level of the fracture permeability around KB-501 and KB-503 that is required to sustain the field injection rates is roughly of the same magnitude (mD) as the matrix permeability.



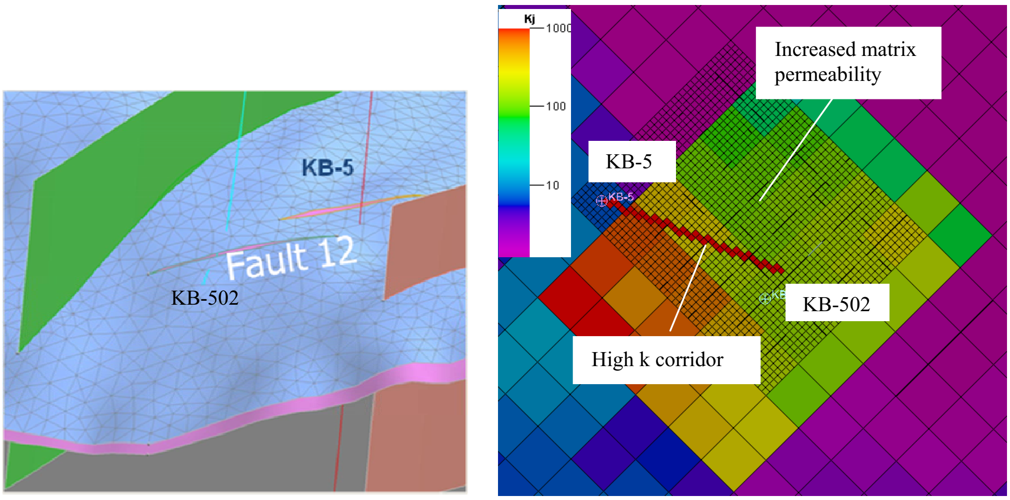
(a) (b)

Figure 3. Implementation of a local fracture network around KB-502 in the reservoir model: (a) a local fracture network based upon the interpretation of the FMI logs by Schlumberger; (b) upscaling to a fracture grid with permeability ~200 mD.

2.2. History matching of CO_2 breakthrough at KB-5

Breakthrough of CO_2 at Kb-5, which produced a whistle at the wellhead, was detected on 28 June 2007 [7]. Given that no CO_2 was observed at the wellhead during the inspection on 25 August 2006, this places the CO_2 breakthrough at KB-5 at sometime between these two dates. KB-5 was drilled in 1980 and crosses the aquifer in the C10.2 formation. Subsequent tracer tests carried out by BP confirm that the CO_2 found at KB-5 is from KB-502. Upon detection of the CO_2, an additional valve was immediately put on wellhead and the CO_2 flow was stopped (the well has now been fully decommissioned) [7].

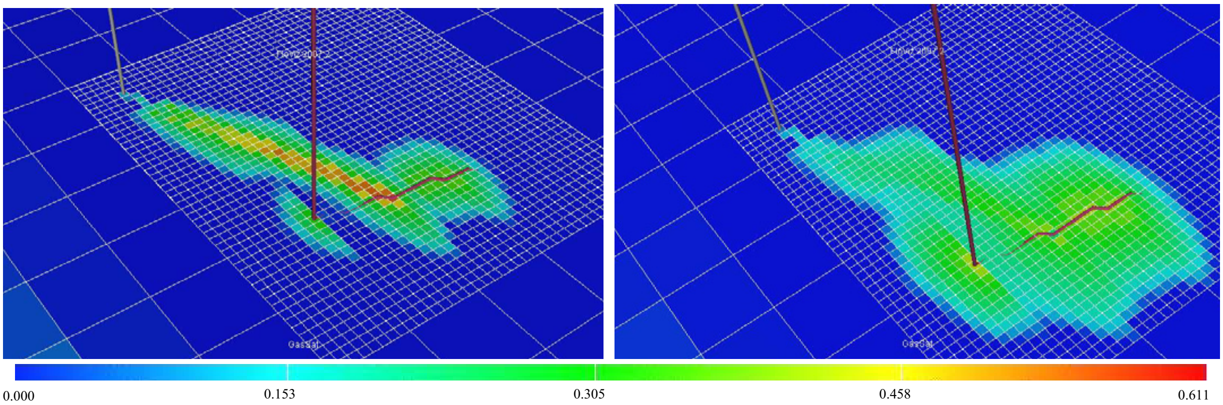
Although the dual-permeability model yielded improved match of the BHP pressure at KB-502, it failed to predict CO_2 breakthrough at KB-5 within the two-year injection period. Fault analysis carried out by the In Salah project team suggests the presence of a NW-trending fault/fracture cutting across KB-502 (Fault 12, Figure 4a) prior to the start of CO_2 injection. Furthermore the fault/fracture is likely to be conductive as it is aligned with the (present-day) maximum horizontal/principal stress (regional strike-slip stress regime) [7]. However, the exact vertical extent of the fracture/fault (above/below the storage unit) is not well constrained, due to the relatively poor quality of the original 1997 3D seismic survey in the overburden.



(a) (b)

Figure 4. (a) Several faults have been identified around Kb-502 and KB-5, among which Fault 12 cuts across well KB-502 [7]; (b) A single-medium model with enhanced local matrix permeability around KB-502, and a high permeability corridor connecting KB-502 and KB-5.

In an attempt to explore the possibility of such a fault/fracture providing an enhanced pathway from the KB-502 injector towards KB-502, a simple scenario involving the placement of a high permeability corridor that connects KB-502 and KB-5 in the reservoir model (Figure 4b) was considered. Note that in Figure 4b, local grid refinement (LGR) is implemented to improve the grid resolution around the two wells. Another advantage of LGR is that the fault can now be represented by much smaller cells of 50 m, rather than 400 m. In view of the full field dual-permeability model simulation results, it was decided to revert to the simpler single-permeability reservoir model. To account for the presence of fractures around KB-502, permeability multipliers were applied to the matrix permeability of the region of interest in the model. Multipliers of 5 and 100 were applied in the x- and y- directions respectively, to represent facture permeability anisotropy.



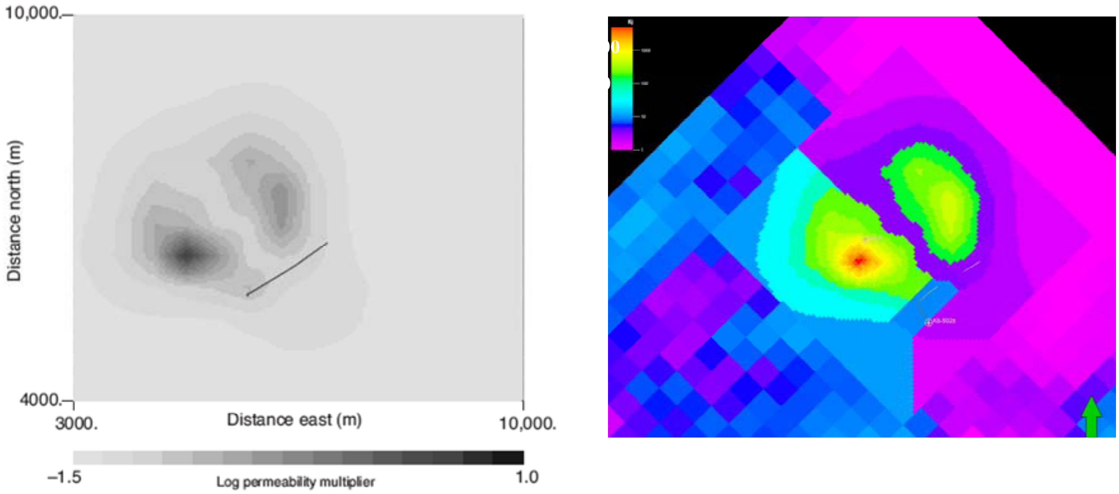
(a) (b)

Figure 5. Simulated CO_2 plume development at the time of Kb-5 CO_2 breakthrough for two different scenarios: (a) 1.9 D corridor – breakthrough would occur in August 2006; (b) 1.0 D corridor - breakthrough would occur in June 2007.

The simulation results showed that a 50 m-wide corridor with a permeability of 1.9 Darcy was required for CO_2 breakthrough to occur at KB-5 in August 2006 (Figure 5a), and a lower permeability of 1 D for breakthrough in June 2007 (Figure 5b). This range of the permeability for the corridor (1- 1.9 D) is also consistent with the work of Ringrose et al. [7]. It was also observed that while the permeability level of the corridor has a significant bearing on the CO_2 breakthrough timing, its impact on the overall well injectivity appears to be rather limited.

3. Integrated reservoir simulation approach

In the light of the satellite monitoring data of the surface deformation at the Krechba gas field, in particular the inverse modelling findings by Vasco et al. [3], and the recent geomechanical studies which provided additional information on the CO_2 injection processes at Krechba, the reservoir model clearly needs to be further updated to account for the pressure distribution inferred from the surface uplift data, as well as matching the injection pressure and CO_2 breakthrough (along the heel-side lobe).



a) b)

Figure 6. (a) Inverted permeability distribution [3]; (b) permeability distribution used in this study to history match CO_2 breakthrough at KB-5.

In the updated reservoir/caprock model, the enhanced permeability zone and the high permeability corridor in C10.2 used in earlier simulations were replaced by the inferred permeability (ratio) distribution (Figure 6a), featuring two high permeability lobes. The assumption of a sealing caprock (C10.3) to the aquifer (C10.2) was relaxed; and the lower cap rock (C20.1) was assigned a low permeability of 10^{-4} mD after Rutqvist et al. [6]. During the history matching, the initial permeability multiplier values were first multiplied by the mean matrix permeability (of the Statoil complex model) to yield the absolute permeability. They were subsequently adjusted to accommodate the reservoir heterogeneity and topography which were not considered by Vasco et al. [3], while their inferred permeability pattern was preserved. For example, it is noted that the horizontal section of KB-502 borehole dips by ~50 m between heel and toe, which is significant compared to the thickness of C10.2 (20 m).

An important aspect of history matching was to strike a balance between honouring the inferred pressure build up in the two lobes, while ensuring CO_2 breakthrough at KB-5 along the heel-side lobe with the two-year injection period. Once a desired balance between the permeability of the two lobes was achieved, the whole permeability distribution was then scaled up or down to match the BHP. The lobes were initially confined to C10.2 only. It was found that an improved match to the field pressure data was obtained if the high permeability lobes were extended to C10.3 to increase the injectivity and storage volume accessible by the injected CO_2.

The history-matched permeability distribution (Figure 6b) features a heel-side lobe with permeability up to 6 Darcys (scaled-up base matrix permeability ~10 mD) and a toe-side lobe with permeability up to 500 mD (scaled-up base matrix permeability ~1.5 mD). In addition, the matrix permeability outside the two-lobes was 50% higher than the original matrix permeability. With this permeability distribution, CO_2 breakthrough at KB-5 is predicted to occur in April 2007 (Figure 7).

Figure 8 shows the comparison between the simulated BHPs, with the BHP estimated by Schlumberger using PIPESIM software. Although an improved overall match is achieved by extending the high permeability lobes to C10.3, a marked divergence in the BHP trend is also observed after August 2006. Clearly further refinement to the reservoir/caprock model is required to resolve this discrepancy.

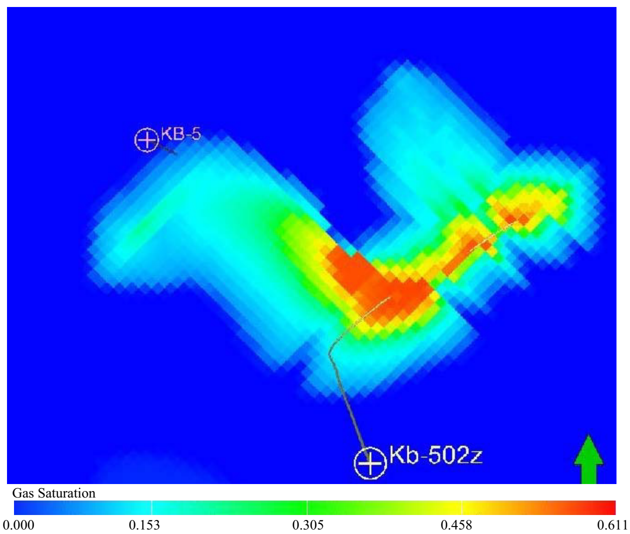


Figure 7. Simulated CO_2 plume development around KB-502 leading to CO_2 breakthrough at Kb-5 (April 2007), using the permeability distribution inverted from surface uplift measurements.

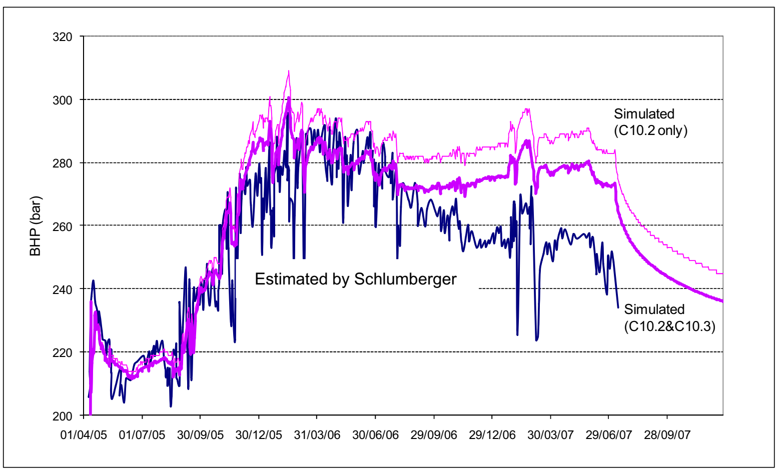


Figure 8. Simulated BHP compared to the estimated field BHP, showing deviation from August 2006.

4. Concluding remarks

Satellite-based interferometry (InSAR) technology has been recognised as a valuable surface monitoring tool for performance assessment of subsurface CO_2 storage at In Salah [7]. Unlike 4D seismic, which images the migration of the CO_2 plume, surface deformation pattern reflects volume change and its distribution at the reservoir level due to CO_2 injection. In this study, the permeability pattern inverted from the surface uplift data by Vasco et al. [3] has been used to further constrain the reservoir model to improve prediction of the CO_2 plume migration around KB-502, so that it is consistent with the surface monitoring data, as well as reservoir-based observations (injection pressures and CO_2 breakthrough at KB-5). The results have shown that the extent of CO_2 plume migration along the toe-side lobe appears to be not as far as the surface uplift data would suggest [7].

It needs to be pointed out that there are alternative interpretations for the observed two-lobed surface uplift pattern over KB-502. Indeed, it is known that opening of a tensile feature at depth can lead to such a response at the surface [8]. Using a 20-layer model of compressional and shear velocity for the region, Vasco et al. [9] showed that the observed two-lobed uplift pattern over KB-502 could be reproduced by the widening by 5 cm of an initially conductive NW-trending 4 km long fracture/fault, extending 40 m above and below the reservoir interval, together with the volumetric expansion within the 20 m thick reservoir layer. The latest effort at Imperial College involved the implementation in the model of a conductive fault, with a fixed aperture initially, but subject to change if tensile failure has taken place later on during injection. By tuning the fracture aperture after the onset of tensile failure, a consistently close match to the Schlumberger BHP curve was obtained. It was found that the BHP matched fracture/fault aperture (post tensile failure) displays dynamic behaviour (narrowing as well as widening), following closely the fluctuations in the CO_2 injection rate/pressure at KB-502.

Acknowledgements

Research reported in this paper was carried out within the framework of European Commission funded project CO2ReMoVe (SES6-2005-CT-518350). Further funding was provided by the EU Marie Curie Research Training Network GRASP (MRTN-CT-2006-035868). The authors wish to thank the EU, the In Salah Gas Joint Industry Project (BP, Statoil, Sonatrach) and CO2ReMoVe project partners for their support and contributions towards their research.

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