Available online at www.sciencedirect.com

SciVerse ScienceDirect

Energy Procedia 37 (2013) 3554 – 3564

Energy Procedia

GHGT-11

Assessing field pressure and plume migration in CO_2 storages: application of case-specific workflows at In Salah and Sleipner.

J.-P. Deflandre[a,*], A. Estublier[a], A. Baroni[a], A. Fornel[a], V. Clochard[a] and N. Delépine[a]

[a] *IFP Energies nouvelles, 1-4 avenue de Bois-Préau, 92852 Rueil-Malmaison, France*

Abstract

Performance assessment of CO_2 geological storage aims at applying a specific workflow adapted to the site to be considered, using iterations between modeling tools and methods together with monitoring techniques. In the frame of the CO_2ReMoVe European project site specific innovative workflows have been applied at In Salah (Krechba reservoir) and Sleipner (Utsira sand formation reservoir) to predict the reservoir pressure field and the associated CO_2 plume migration. The workflows we applied benefit from appropriate site monitoring techniques: respectively InSAR satellite imaging for the Krechba reservoir and 4D Seismics for the Utsira sand formation storage. Indeed, simulation of the reservoir pressure and the plume migration are the two major modeling issues to deal with when considering storage efficiency and safety -together with public awareness when addressing the public acceptance issue.

Keywords: Carbon geological storage; performance assessment; modeling; monitoring feedbacks; Sleipner; In Salah

Introduction

Assuming a site has been identified, characterized and finally validated for CO_2 storage, the next step when assessing site performance is to demonstrate that prediction is reliable and storage safe at short-term in order to make predictions credible at long-term after site abandonment.

In the frame of the CO_2ReMoVe European research project, partners aimed at developing tools and methods for site performance assessment and monitoring of CO_2 geological storage. They benefited from a series of pilot sites to develop and apply the techniques investigated while making their validation possible (*i.e.* assessment and verification) [1]. In this context IFP Energies nouvelles (IFPEN) focused on

* Corresponding author.
E-mail address: jean-pierre.deflandre@ifpen.fr

doi:10.1016/j.egypro.2013.06.248

assessing the short-term field reservoir pressure and the associated CO_2 plume to make long-term prediction the most reliable as possible. Applied methodologies consist in iterative approaches where modeling and comparison with data observed on fields alternate until converging to a reliable simulation of the site behavior. In addition to technical benefits such as understanding the storage behavior and increasing the confidence in the predictions, these methodologies are also very important for public acceptance as they demonstrate the efficiency and the strength of integrated approaches to substitute to a lack of direct measurements. Indeed, predicting the reservoir pressure and the associated CO_2 plume migration in 3D is compulsory to make risk management possible but it also allows to honor a constructive dialog between operators, authorities and the public.

Considering risk assessment and risk management, the reservoir overpressure footprint remains the key parameter to model, since it is the driving force of the system. If too important, the pressure may significantly modify the *in situ* effective stress equilibrium with the risk of:

- hydraulic fracturing the caprock (mainly in the injection area) or,
- reactivating a fault (or a fracture network) into but also out of the reservoir -or out of the assumed storage complex itself.

Both scenarios deal with hydro-poro-mechanics since underground mechanical instabilities may occur, inducing some micro-seismicity/seismicity. For the second scenario, it does not mean that the injected fluid systematically migrates up to the mechanically active zone. Most of the time, it just corresponds to an *in situ* effective stress redistribution on a fault plane more or less distant from the injection area itself. This is quite common and it has already been observed when storing natural gas underground [2].
The hydraulic fracturing risk is in principle easier to anticipate and at least to manage. On the contrary, the risk of reactivating a fault is more difficult to anticipate as the fault mechanical equilibrium is unknown and since such phenomenon can result from a relative low modification of the effective stresses applied on the fault plane.

In both cases, there is a risk of CO_2 leakage. For the hydraulic fracturing scenario, this risk is of course higher but it could be pondered by the caprock thickness. For the fault reactivation scenario, the risk is maximum in presence of CO_2 in the vicinity of a fault. To reduce uncertainty while stating on the risk of leakage itself, predicting and mapping the CO_2 plume extent is mandatory. Indeed, short-term injection simulation results can suggest to stop or manage differently the injection or in the worst case to renounce storing CO_2 in the selected reservoir. Also, to anticipate and manage such risks or for possible remediation purposes, the site operator has to run modeling tools while integrating short-term monitoring feedbacks to make early performance scenarios becoming relevant predictions. In other words, mimicking the short term observations is thus crucial to calibrate the models.

The modeling and monitoring of the site behavior has to be adapted for each site to benefit from the most efficient and relevant monitoring feedbacks. When developing the risk assessment, but also when integrating public acceptance purposes, the approach has to be exhaustive at the beginning to become more 'effective-risk' driven over time. Different tools can be used to identify and prioritize these different risks while designing a large-spectrum series of site evolution *scenarios* [3]. In addition, sensitivity studies based on different design plans are compulsory to state on and reduce uncertainties. At least, when considering the whole problematic of site performance assessment (PA), the combination of tools and methods would help verifying site behavior prediction at long-term while applying an appropriate monitoring strategy (which will have to be elaborated in agreement with risk assessment and public awareness requirements). The corresponding workflow is illustrated in Figure 1; it assumes communication between project stakeholders to start at the early beginning of the project when framing the problem. The preliminary steps are fundamental especially the site characterization and the baseline monitoring as reference information will nevermore be accessible after CO_2 injection starts. This assumes an exhaustive screening of risk factors. On the basis of this information, site operator and partners develop the risk analysis and the associated PA workflow in parallel with site monitoring to make verification possible -such as remediation if necessary.

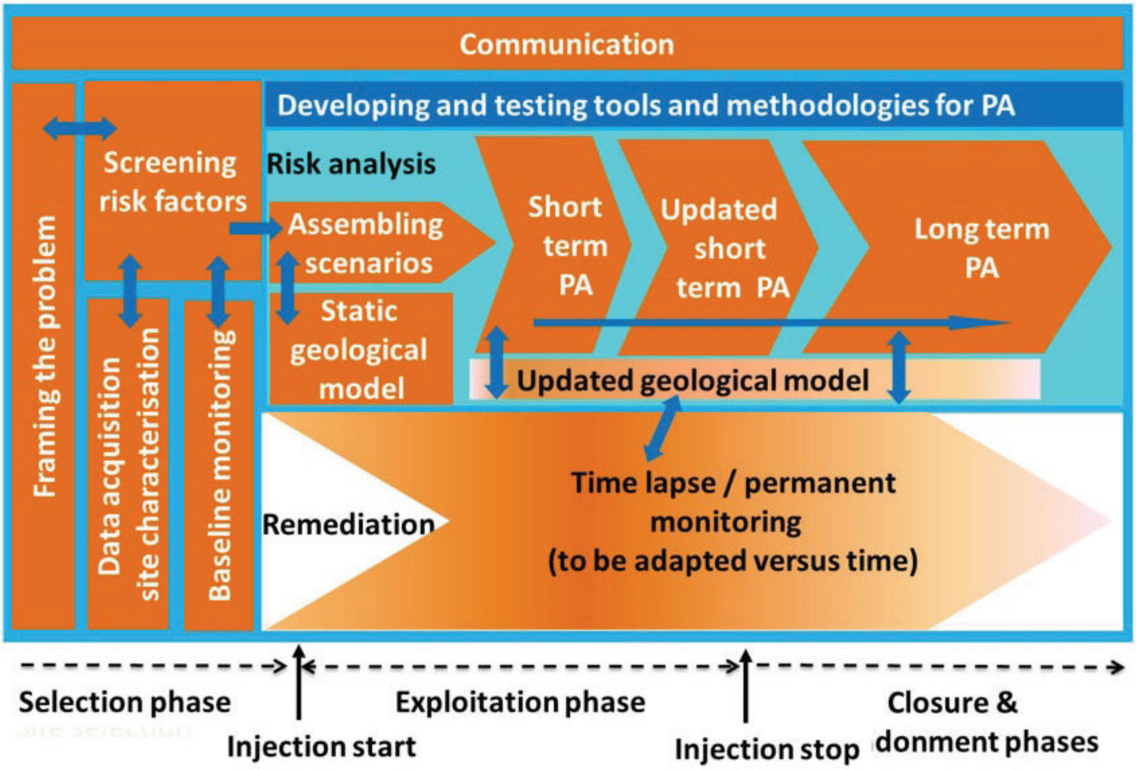


Fig. 1. Site performance assessment workflow in the frame of CO_2 geological storage (source IFPEN).

We do not discuss monitoring strategies in this paper, we are just reporting on the use of relevant techniques and methodologies that allow to verify and improve early PA prediction. In practice, after presenting the 3D fluid flow modeling workflow, we comment on two specific cases:

- CO_2 re-injection into the Krechba gas reservoir aquifer (In Salah project - On-shore Algeria),
- CO_2 storage into the Utsira formation (Sleipner project - North Sea, Off-shore Norway).

In both cases, we use 3D fluid flow modeling to compute the reservoir field pressure and the CO_2 plume migration. Major challenges deal with a multi-scales and multi-physics problem that has been simplified for short-term PA evaluation by not considering reactive transport. In practice, we just model fluid transport considering thermodynamics and phase transfers. Of course, for long term prediction, geochemical effects would have to be considered as they can play an important role in the sealing evolution of the well completion or on rock intrinsic mechanical and petrophysical properties at long term.

Modeling efficiency requires early scenarios to be verified and improved by monitoring feedbacks in order to deliver reliable predictions for the long term. The elaboration of the static reservoir model and the way it is improved over time are crucial.

3D Fluid flow reservoir modeling workflow

Reservoir pressure is the key parameter to model when assessing both site performances and risks. Indeed, in any geological / petrophysical context, the reservoir pressure:

- drives fluid migrations and especially in our scope the CO_2-saturated brine and the free CO_2 at supercritical state or as a dense fluid (often abusively named as the gas phase);
- modifies the *in situ* state of the effective stresses (at wellbore but also in the whole storage complex as explained above);
- acts on thermo-dynamical and geochemical reactions when considering, fluids, rocks, cements and casings.

When dealing with reservoir pressure and risk assessment, it is thus important to pay attention to important pressure levels around the injector wells -that may induce hydraulic fracturing of the formation and its caprock. We have also to consider possible *in situ* effective stress modifications within the whole storage complex that might allow an existing fault to be mechanically solicited. This could be mainly the case when injecting too fast and/or too close to a fault, or in a compartmentalized reservoir or when operating at a location where tectonics is "active". Major consequence to be expected is the triggering of an earthquake of more or less energy. In this context, monitoring deals essentially with pressure monitoring completed with micro-seismic monitoring. It is more reliable to record the pressure downhole at the reservoir level than at wellhead and it is very informative to also record upper aquifers pressure (if any) for hydro-mechanical model calibration. In the same way downhole micro-seismic survey is better as it makes it possible to record low energy events while in addition reducing location uncertainties.
Theoretically, thermal effects should also be considered especially when the temperature of the injected CO_2 significantly differs from the one of the reservoir or when the reservoir thickness is important enough to have temperature variations (assuming a significant vertical temperature gradient). In some particular conditions, long-term injection may induce thermal fracturing. To state on such a case, temperature measurements can be easily achieved by deploying optical fiber technologies into the well (for example a Distributed Temperature Sensor that will give the well temperature profile).

The second major target to model is the CO_2 plume migration itself while considering the different CO_2 trapping mechanisms, the risk of leakage being related to the presence of CO_2.

Early PA scenarios lay on the use of a preliminary static model which is elaborated by using conventional field data (seismics, well data such as logs and cores, reservoir outcrop analogues...) as commonly done in oil and gas production studies. Nevertheless, when considering CO_2 geological storage, improvement of the reservoir model description is more challenging as history matching on production data is not possible and because of a limited number of injection wells. At least, reservoir engineers can only use well(s) injection data and monitoring feedbacks as suggested in Figure 2 to mimic injection data and make injection *scenarios* with associated risks management studies. Such an approach is nevertheless helpful for injection forecasts.

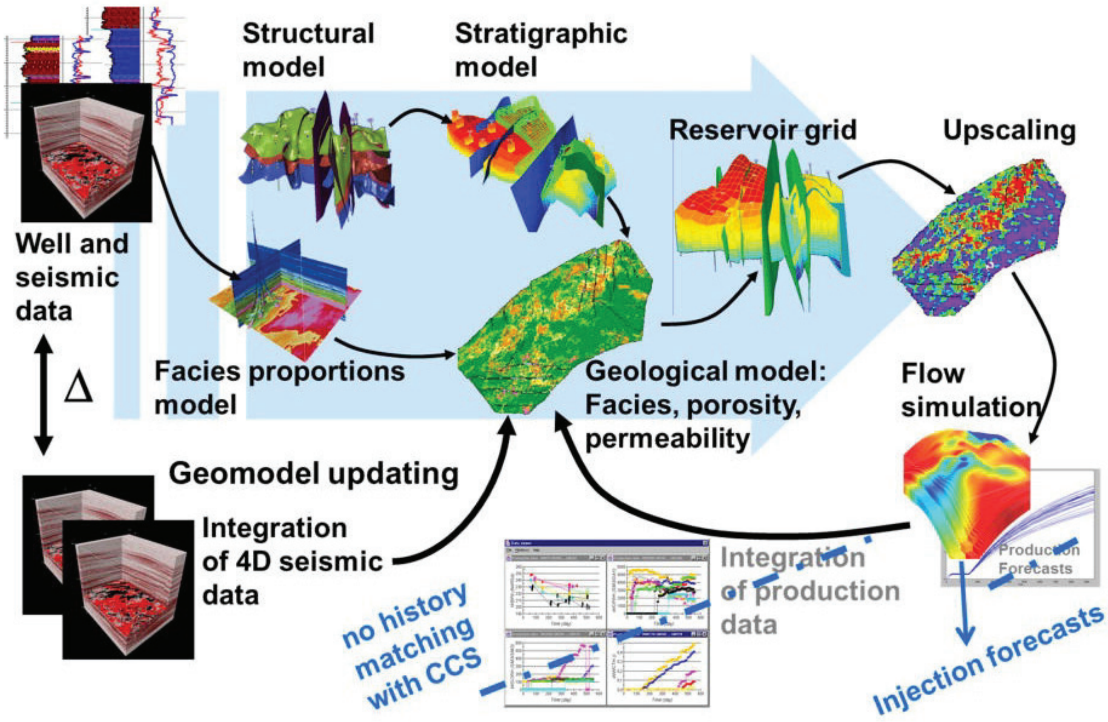


Fig. 2. Model reservoir elaboration and improvement workflow adapted to the context of CO_2 geological storage. In this case, 4D seismic monitoring is used to reduce model uncertainties. Other time-lapse techniques can be used depending on site specificities (source IFPEN).

Developing new methodologies and appropriate workflows to be used instead of production data to verify and constrain simulations and to reduce uncertainties is then of prime interest. The following sections present the results and conclusions of the methodologies applied by IFPEN in the framework of the CO_2ReMoVe project at In Salah and Sleipner. These methodologies are based on the use of appropriated field measurements, respectively surface ground deformation and 4D seismic monitoring, to verify 3D field reservoir pressure prediction or to constrain the associated plume migration -in the Sleipner case. In practice, data to be used are site dependent and a major difficulty is the availability of a baseline dataset adapted to the monitoring tools and relevant over time to state on the site behavior. Multi-physics phenomena have also to be considered. Depending on the importance of these phenomena, implicit coupling could be necessary to have a dynamic model and to enable the modeling of the evolution of these phenomena in real time. In the two following examples, reservoir updates were simply achieved on request and controlled by monitoring feedbacks. When monitoring feedbacks and simulations fit, one can consider the model to allow injection forecasts (by analogy with the oil & gas industry where simulations aims at making production forecasts).

Modeling 3D field reservoir pressure and associated geomechanical effects at In Salah

At In Salah, the CO_2 produced from the Krechba reservoir (Figure 3) is re-injected at the periphery of the gas reservoir below the gas water contact in the northern and eastern zones [4, 5]. Reservoir modeling has been validated using the exploitation data of the site (from August 2004 to August 2006) and the occurrence of a CO_2 breakthrough at an abandoned appraisal well [6]. To fit with field data, the initial one-medium reservoir model has been replaced after a series of simulation tests by a dual-media reservoir model to take into account the reservoir natural fracture network in fluid flow modeling [6].

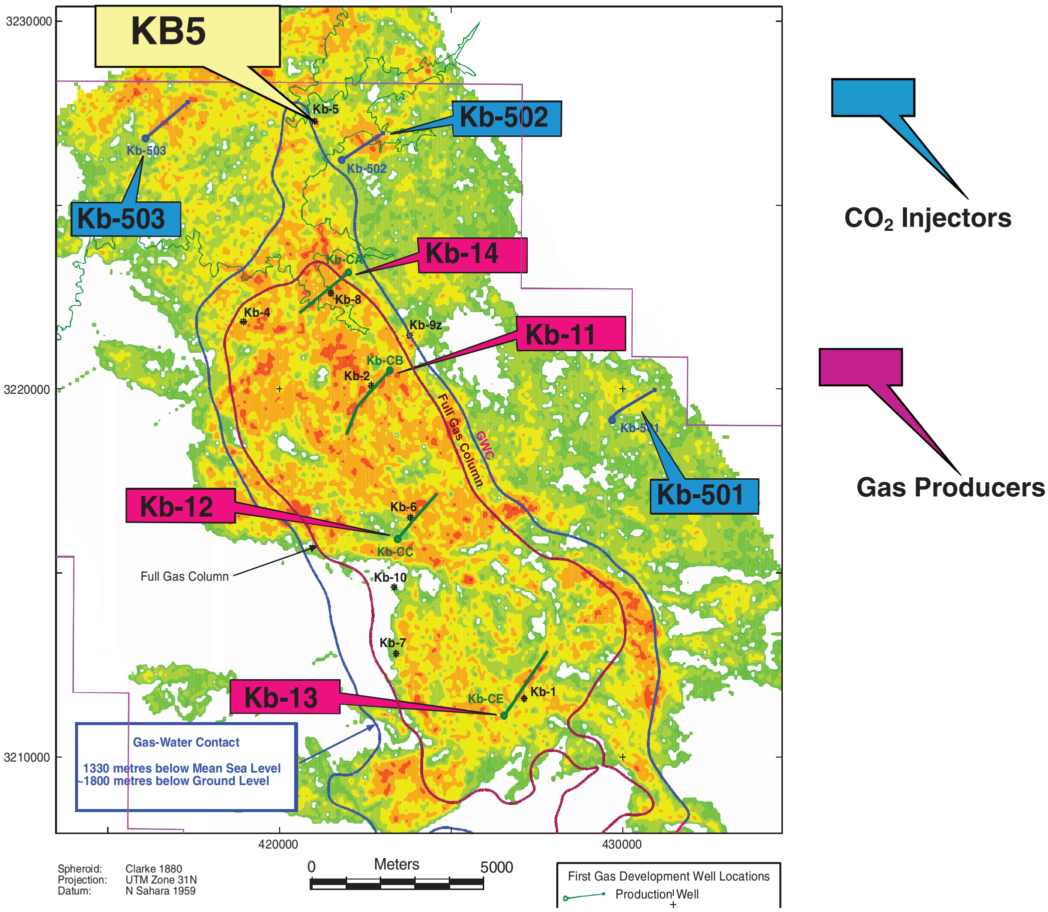


Fig. 3: Production and injection well location at Krechba (source BP).

Soon after CO_2 injection started, ground surface displacements were observed by InSAR satellite imaging and analyzed by different research groups [7, 8, 9, 10, 11]. These displacements of quite moderate amplitude (20 mm maximum) were clearly observed thanks to the nature of ground surface at this location. They directly testimony from the underground reservoir exploitation, showing subsidence above the produced gas reservoir and uplift at CO_2 injectors. These data have been rapidly used to analyze and interpret the reservoir and overburden geomechanical behavior. In our case, they have been determinant for the validation of the field reservoir pressure simulation [12].

After having built an extended geomodel popularized with petrophysical and mechanical properties, we have computed surface ground displacements by coupling 3D fluid flow and geomechanical modeling - assuming an elastic mechanical behavior of rocks [6, 12]. Comparison of simulated and monitored ground surface displacements first validated the prediction of the geometry of the field pressure extension. They were in a second time used to calibrate the coupled 3D fluid flow - geomechanical modeling amplitude results for Krechba [12].

Figure 4 shows the comparison of the simulated surface ground displacements with the ones measured by InSAR satellite imaging after an initial calibration of mechanical parameters. In both injection and producing areas, a good fit is observed, with at least a 17 mm-uplift at injectors at end of the period. During the first months of injection, quite a good fit was observed and there was no need to update the model parameters. However September 2005 observations made it necessary to modify reservoir mechanical parameters to maintain a good fit with observations (*i.e.* InSAR data) [12]. Such a deviation over time is very valuable since it informs on the dynamic behavior of the reservoir under injection; it has been interpreted as the "opening" or simply the solicitation of the initial fracture network [12]. Such an interpretation should be confirmed by the observed micro-seismic activity but at that time the uncertainty on the microseisms location does not allow to draw any reliable conclusion.

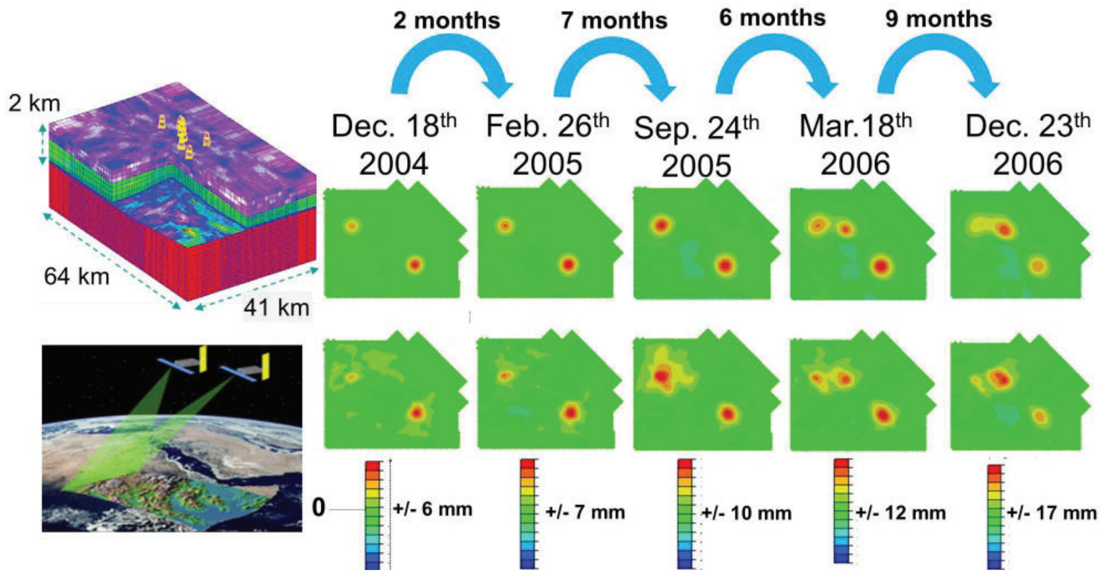


Fig. 4. Comparison of simulated and observed surface ground displacements at Krechba (source IFPEN).

At least, the approach applied here helps at validating reservoir modeling and identifying when modeling parameters shall be updated to take into account reservoir property changes. However it remains difficult to state on the nature of such changes and to dissociate the effects of the different parameters, *i.e.,* between porosity, permeability, rock or reservoir compressibility and other mechanical parameter effects. Such results call for a better characterization of the state behavior laws that could be derived from core laboratory experiments. Such an improvement would be efficient for short-term performance assessment but it would be more complex at long term when also considering reactive transport issues.

As a conclusion, we can consider that surface ground displacement monitoring has been efficient to validate 3D fluid flow modeling and especially 3D field pressure modeling in the case of Krechba. A similar approach can be applied in some other cases but it might not be applicable or suitable for all contexts. When applicable, it is of prime interest for risk assessment as it allows to map pressure variation induced effects as well as their evolution and dissipation over time. It might also be very helpful for remediation monitoring.

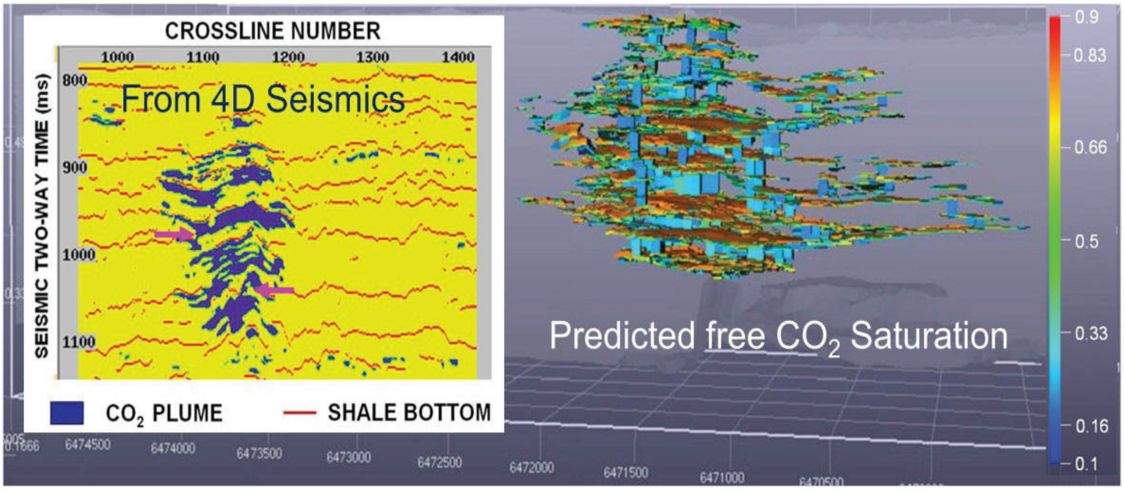
Modeling 3D field reservoir pressure and plume migration at Sleipner

Sleipner is the first CO_2 storage industrial pilot; it has been operated since 1994 by Statoil [13]. CO_2 produced from the natural gas reservoir is re-injected into the Utsira sand formation which corresponds to an extended and very permeable saline formation. Sleipner is the reference case when dealing with CO_2 plume migration mapping [13, 14]. Here, pressure management is not a strong issue; but on the contrary 3D fluid flow prediction is a challenge as reported below. In practice, the preliminary reservoir model that was used did not allow to model the migration of the CO_2 plume in agreement with what was observed on 4D seismic data. To mitigate such discrepancies IFPEN has checked, in the frame of CO2ReMoVe, an innovative methodology based on the use of 4D seismic data inversion to constrain the reservoir model description. In other words, we aimed at benefiting from the good quality of time lapse seismic information to improve the allocation of reservoir properties within a specific inversion loop where we minimized differences between observed seismic data and synthetic ones. The approach has been validated on the 1994 and 2006 seismic acquisition vintages, the earliest vintage corresponding to the reference seismic acquired prior to CO_2 injection. The inversion technique combines pre-stack seismic data and an *a priori* elastic model parameterized by *P*- and *S*-wave impedances to retrieve the variations of elastic impedances between the two vintages. These variations are then interpreted in term of CO_2 plume migration. The technique and the whole approach have been already described [15], we focus here on its advantages and limitation for short and long term PA and for risk assessments.

At Sleipner, the observation of the CO_2 plume within the Utsira sand saline aquifers is easy, on the contrary modeling this plume by 3D fluid flow modeling remained challenging without introducing artifacts in the model such as “permeability holes” in the layers that would allow unexpected fluid paths. This is mainly due to the thin and discontinuous intra-reservoir shale layers that act as non-continuous migration barriers within the very porous and permeable Utsira sand formation. Their thickness (which is less than 1 m) is most of the time below the seismic resolution and, as a consequence, their delineation remains impossible or, at best, poorly reliable. The way we improved the static model delivered in the project in order to have a more robust static model for our inversion process, such as details of the inversion methodology, is reported by Fornel and Estublier [16]. This is a pragmatic approach that combines a deterministic allocation of the shale facies and a static one. When CO_2 remains blocked in a layer we assume a 100%-shale facies in the reservoir cells located above and sandstones in the storage cell. For the other cells a conventional facies leopardization is achieved. After a series of iterations, we obtained an optimal reservoir model that can be used to run 3D fluid flow modeling using the COORES^{TM} IFPEN's software. Using a Petro Elastic Model (PEM) then allowed to compute P-wave impedance variations between 1994 and 2006 based on field injection parameters. These variations were then compared with the one derived from the joint seismic inversion of the two acquisition vintages. Four iterations have been necessary to obtain a good fit: the first model shows most of the CO_2 rapidly reaching the top of Utsira [16]. The fourth model iteration led to a more representative plume mapping as presented in Figure 5. This figure shows the CO_2 plume mapped from seismic data inversion and the one predicted at the same date. These results are quite good as no 'artifact' has been introduced in the reservoir parameters popularization process: when justified we fixed the rock facies otherwise it was statically distributed [16].

Major limitations are related to a lack of information especially for the elaboration of the *a priori* velocity model but this is site dependent and they do no limit the potential of such an approach. Computing time is quite important and data management and processing required some expertise. Improvements are possible as a series of assumptions have been made when applying the workflow:

- A better *a priori* elastic model (used in the seismic inversion technique) could have been elaborated if more well information was available;
- More advanced technique of inversions such as tomography ones [17] can be used;
- Use of a PEM for seismic impedance computation [18].
- The 3D fluid flow and joint seismic inversion loop (used to minimize the differences between computed and measured P-wave seismic impedance) should be first applied for the first two vintages (1994 and 1999) and complemented over time from the new ones in the joint inversion process (*i.e.* by successively considering 1994, 1999, 2001 jointly and so on... until integrating the last acquisition vintage). This would have the strong advantage to improve 3D fluid flow imaging at a particular location over time and at least to improve the reliability of the mapping of the CO_2 plume considering the different CO_2 phases and short term trapping mechanisms. This would also contribute to better model CO_2 plume content within the plume thickness over time, which remains more challenging than mapping the plume extension itself.
- The use of the S-wave impedance variations in addition to the use of the P ones to have a better reservoir anisotropy characterization [19].



(a) (b)

Fig. 5. CO_2 plume prediction at Sleipner; (a) CO_2 plume from 4D seismic data joint inversion of vintages 1994 and 2006, (b) predicted CO_2 plume using 3D fluid flow modeling constrains by time-lapse seismic data [16] (source IFPEN).

At least, this is a very promising approach that will benefit to more reliable long-term prediction, which is of prime interest for PA and risk managements. Especially, as illustrated by Estublier *et al.* [20], it is also important when evaluating trapping mechanism effects as 3D fluid flow can directly and strongly impact reactive transport efficiency in the long term. The earlier the better for application of the methodology as it first helps at properly modeling initial 3D fluid flow at the injection point while also progressively extending the mapping of the CO_2 invaded reservoir volume with the successive integrations of the new time-lapse measurements. Unfortunately we missed time in the project to fully benefit from the application of this innovative approach and we only considered two time-lapse seismic data sets (1994 and 2006) among the five existing ones. But the results we obtained are already very promising. In addition, significant improvements are also expected from the application of the complementary works achieved in the research project on 4D joint pre-stack travel time tomography [17] and from the introduction of a petro elastic model exploiting the inversion of a 3D cube of CO_2 saturation with a detailed structure of the reservoir plume [18].

Conclusions

Prediction of CO_2 storage reservoir pressure and associated CO_2 plume migration are the most important targets when addressing site performance assessment and risk management of CO_2 geological storages. We have presented here two integrated workflows combining modeling techniques together with monitoring feedbacks. At In Salah we benefited from ground surface displacements imaging to validate the field reservoir pressure 3D modeling. Here it is important to note that the approach also helps at better stating on when the update of model parameters becomes necessary. At Sleipner, we applied an innovative history matching loop based on the joint inversion of 4D seismic data sets used to constrain 3D fluid flow prediction within the Utsira formation. This technique helped at better understanding the important role of thin intra-reservoir shale layers in fluids migration. Possible improvements have been identified and design plans for sensitivity studies are recommended to reduce uncertainties.

Such methodologies are site dependent. When applicable, they may deliver robust results provided that baseline data are available. Their efficiency also depends on the frequency of the monitoring feedback. They can contribute to identify missing (but relevant) information and help to design monitoring campaigns. In both cases, it is a dynamic process which is crucial for robust short-term simulations and at least for more reliable long-term predictions. They are part of the whole-system process modeling strategy [21].

In the context of CCS, methodologies such as those presented here are also very important in terms of public acceptance and they are very useful for discussion between stakeholders: for example we used these CO_2ReMoVe results to report to regulators at the UNFCCC workshop held in Abu Dhabi in September 2011 in preparation of the Durban conference on climate change (December 2011). In addition, it is important to keep in mind that a lot of innovative research works have been recently achieved worldwide and in parallel in the frame of recent CO_2 storage pilot projects. Their integration to the state of art is just starting and so, we can expect relevant improvements in the next decade for a larger scale deployment of CCS.

Acknowledgements

The authors thank the CO_2ReMoVe European project (Contract n° SES6 518350 funded by the EU 6th framework programme and industry partners BP, ConocoPhillips, ExxonMobil, Statoil, Schlumberger, Total, Vattenfall and Wintershall) to allow the publication of this work. They are also grateful to all partners for fruitful technical comments during project discussion. The success of the CO_2ReMoVe project depends to a large degree on the accessibility of the storage sites and associated data; we thank Statoil and the In Salah Project partners: BP, Sonatrach and Statoil for provision of site data.

References

[1] Wildenborg T, Chadwick A, de Coninck H, Deflandre J-P, Mathieson A, Metcalfe R, Schmidt Hattenberger C, Wollenweber J and Eiken O. Key messages from active CO_2 storage sites. GHGT-11 Conference, Kyoto, 19-22 Nov 2012.

[2] Deflandre J.-P., Dubos-Sallée N., Huguet F., 2009, "Passive seismic monitoring of gas storage: challenges for improving interpretation and reducing uncertainties", EAGE Workshop on Passive Seismic, Limassol, Cyprus, 22-25 March 2009.

[3] Metcalfe R, Paulley A, Suckling PM, Watson CE. A Tool for Integrating and Communicating Performance-Relevant Information in CO_2 Storage Projects: Description and Application to In Salah. GHGT-11 Conference, Kyoto, 19-22 Nov 2012.

[4] Mathieson A, Midgeley J, Wright I, Saoula N and Ringrose P. In Salah CO_2 Storage JIP: CO_2 sequestration monitoring and verification technologies applied at Krechba, Algeria. Energy Procedia 2011; 4:3596–3603.

[5] Ringrose P., Atbi, M., Mason, D., Espinassous, M., Myhrer, O., Iding, M., Mathieson A., Wright, I., 2009. Plume development around well KB-502 at the In Salah CO_2 storage site. First Break. 27, 49-53.

[6] Deflandre J-P, Estublier A, Baroni A, Daniel J-M and Adjémian F. In Salah CO_2 injection modeling: a preliminary approach to predict short term reservoir behavior. Energy Procedia, 4; 2011 p. 3574-3581, 2011.

[7] Vasco DW, Ferretti A and Novali F. Reservoir monitoring and characterization using satellite geodetic data: Interferometric synthetic radar observations from the Krechba field, Algeria, Geophysics, 73 (6), WA113-WA122, 2008.

[8] Rutqvist, J., Vasco, D.W., Myer, L., 2009. Coupled reservoir-geomechanical analysis of CO_2 injection at In Salah, Algeria. Energy Procedia, 1(1), 1847-1854. Proc. GHGT-9, 16–20 November 2008, Washington DC, USA.

[9] Mathieson A., Wright, I. Roberts, D. and Ringrose, P. S. [2008] Satellite Imaging to Monitor CO_2 Movement at Krechba, Algeria. Proceedings of the 9th International Conference on Greenhouse Gas Control Technologies, www.sciencedirect.com.

[10] Onuma T. and Ohkawa S., Detection of surface deformation related with CO_2 injection by DInSAR at In Salah, Algeria, Energy Procedia 1 (2009) 2177–2184.

[11] Vasco, D.W., Rucci, A., Ferretti, A., Novali, F., Bissell, R.C., Ringrose, P.S., Mathieson, A.S., Wright, I.W., 2010. Satellite-based measurements of surface deformation reveal fluid flow associated with the geological storage of carbon dioxide. Geophys. Res. Lett. 37, L03303, doi: 10.1029/ 2009GL041522.

[12] Baroni A, Estublier A, Deflandre J-P and Daniel J-M, In Salah CO_2 injection modelling: a preliminary approach to predict short term reservoir behaviour. American Rock Mechanics Association, 45^{th} US Rock Symposium, June 2011, San Francisco, CA, USA.

[13] Arts R, Chadwick A, Eiken O, Thibeau S & Nooner S. Ten years' experience of monitoring CO_2 injection in the Utsira Sand at Sleipner, offshore Norway, First Break, 26, 65-72 -2008.

[14] Chadwick A, Williams G, Delépine N, Clochard C, Labat K, Sturton S, Buddensiek M-L, Dillen M, Nickel M and Lima AL. Quantitative analysis of time-lapse seismic monitoring data at the Sleipner CO_2 storage operation, The Leading Edge, 29 (2), 170–177, doi:10.1190 / 1.3304820 - 2010.

[15] Clochard V, Delépine N, Labat K and Ricarte P, CO_2 plume imaging using 3D pre-stack stratigraphic inversion: A case study on the Sleipner field, First Break, 28 (1), 91–96, 2010.

[16] Fornel A., Estublier A. To a dynamic update of the Sleipner CO_2 storage geological model. GHGT-11 Conference, Kyoto, 19-22 Nov 2012. Energy Procedia 37 (2013) 4902 – 4909.

[17] Broto K, Ricarte P, Jurado F, Etienne G and Le Bras C. Improving seismic monitoring by 4D joint prestack traveltime tomography: Application to the Sleipner CO_2 storage case, 1st Sustainable Earth Sciences Conference & Exhibition, B18, Valencia, Spain, 8–11 November 2011.

[18] Dubos-Sallée N and Delépine N. Data-driven quantitative analysis of gas saturation in underground reservoirs from 4D inversion of seismic data - Application to the CO_2 storage (Utsira sand formation) at Sleipner site, 20^{th} WPC, Doha, Qatar, 4-8 December 2011.

[19] Dubos-Sallée N and Rasolofosaon P. Estimation of permeability anisotropy using seismic inversion for the CO_2 geological storage site of Sleipner (North Sea), Geophysics, 76 (3), B1–B7-2011.

[20] Estublier A, Fornel A, Parra T and Deflandre J-P. Sensitivity study of the reactive transport model for CO_2 injection into the Utsira saline aquifer. GHGT-11 Conference, Kyoto, 19-22 Nov 2012, Energy Procedia 37 (2013) 3574 – 3582.

[21] Metcalfe R, Bond AE, Maul PR, Paulley A. Whole-System Process Modelling of CO_2 Storage and its Application to the In Salah CO_2 Storage Site, Algeria. GHGT-11 Conference, Kyoto, 19-22 Nov 2012, Energy Procedia 37 (2013), 3859-3866.