EPJ Web of Conferences **54**, 01004 (2013)
DOI: 10.1051/epjconf/20135401004

Large-scale CO_2 storage — Is it feasible?

H. Johansen

Institute for Energy Technology - Instituttveien 18, Kjeller, Norway

Summary. — CCS is generally estimated to have to account for about 20% of the reduction of CO_2 emissions to the atmosphere. This paper focuses on the technical aspects of CO_2 storage, even if the CCS challenge is equally dependent upon finding viable international solutions to a wide range of economic, political and cultural issues. It has already been demonstrated that it is technically possible to store adequate amounts of CO_2 in the subsurface (Sleipner, InSalah, Snøhvit). The large-scale storage challenge (several Gigatons of CO_2 per year) is more an issue of minimizing cost without compromising safety, and of making international regulations. The storage challenge may be split into 4 main parts: 1) finding reservoirs with adequate storage capacity, 2) make sure that the sealing capacity above the reservoir is sufficient, 3) build the infrastructure for transport, drilling and injection, and 4) set up and perform the necessary monitoring activities. More than 150 years of worldwide experience from the production of oil and gas is an important source of competence for CO_2 storage. The storage challenge is however different in three important aspects: 1) the storage activity results in pressure increase in the subsurface, 2) there is no production of fluids that give important feedback on reservoir performance, and 3) the monitoring requirement will have to extend for a much longer time into the future than what is needed during oil and gas production. An important property of CO_2 is that its behaviour in the subsurface is significantly different from that of oil and gas. CO_2 in contact with water is reactive and corrosive, and may impose great damage on both man-made and natural materials, if proper precautions are not executed. On the other hand, the long-term effect of most of these reactions is that a large amount of CO_2 will become immobilized and permanently stored as solid carbonate minerals. The reduced opportunity for direct monitoring of fluid samples close to the reservoir, the general pressure build up, and the reactive nature of CO_2, have created a need for new research and knowledge, to be used in conjunction with operating competence from the oil and gas industry. Experimental work on fluid flow, deformation and reaction, as well as simulations to predict the future performance of the injected CO_2, are much more important in connection with CO_2 storage, as compared with conventional oil and gas production. To conclude this overview of the CO_2 storage challenge, the technical feasibility of large-scale CO_2 storage has been demonstrated. The cost is however going to be significant, especially in the initial phase. The public acceptance of CCS, and the willingness to pay the bill, will depend on several important factors: a serious acceptance of the climate problem, economic and political regulations that are globally fair, and the willingness of each and one of us to accept a higher price for energy.

1. – Introduction

The Institute for Energy Technology (IFE) is a research foundation with a broad focus on all the important energy sources and carriers. In 2009 the IFE CO_2 Center was established to coordinate all its activities related to carbon capture and storage (CCS). IFE is a leading part in the Norwegian Center of Excellence (SUCCESS) for research on CO_2 storage.

The global climate challenge is not only a question about the technical competence needed. Even more important is the attitude of decision makers in economics, politics and culture. The price of fuel and energy will have to increase in the more developed part of the world. The focus of this paper is however on the scientific part of the challenge, including some concern about public acceptance.

Figure 1 shows the Blue Map Scenario which implies a reduction of CO_2 emissions of 43 Gt by 2050. 20% of this reduction will have to come from CCS. This means that 8–9 Gt of CO_2 will have to be stored each year. As present day pilots are rather small (typically 1–3 Mt CO_2 per year), and because less than 10 such projects are in operation, the Blue Map Scenario translates into a needed upscaling of storage by a factor of about 1000. Most pilots are injecting quantities that are far below their capacities, so the amount of experience of pressure and stress development in full scale operations is essentially lacking. The storage challenge is also a question about the time scale of security. The longest living CO_2 pilot project (Sleipner) have been operating for about 16 years. The time window of risk concern is commonly estimated to be in the order of 10^3 to 10^4 years.

The objective of the paper is to point out that there are no insurmountable obstacles to large-scale CO_2 storage, but that we must accept that it is necessary to start early to gain enough experience on how to operate large-scale CCS. The paper will identify the

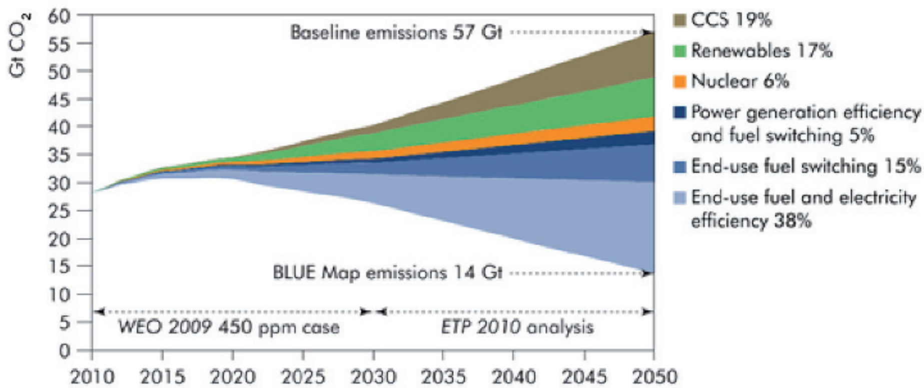

Fig. 1. – The Blue Map Scenario for global climate abatement.

most essential requirements for safe large-scale CO_2 storage, the knowledge that needs to be improved as we go along, and the potential of stimulating further economic growth in the future, without compromising environmental challenges.

2. – The storage challenge

The requirements for reservoirs for CO_2 storage are several. They must contain enough pore space to accept the planned amount of CO_2 to be injected, and the injection must not lead to the build up of pressure that may potentially fracture the reservoir and sealing sediments. A high porosity is important, but it is not a sufficient condition for successful and safe operation. The pore geometry may be even more important than the porosity, as the flow properties are more sensitive to the pore throats, than to the total pore volume. Permeability at various scales (pore scale, bed scale, reservoir scale, basin scale) is a major challenge, as many porous rocks do not possess very good flow properties. Reservoir rocks may be of many kinds. They may be sandstones, limestones, or even volcanic rocks. These different reservoir rocks display a very large variation with respect to the geometry of the pore space, and accordingly also with respect to porosity and permeability.

All kinds of reservoir rocks are heterogeneous with respect to petrophysical properties, and some internal reservoir layers may be so impermeable that they function as barriers. Heterogeneities and barriers are of major importance when it comes to displace water as fast as CO_2 is being injected. There are not two reservoirs in the world that have identical flow structures, and the mapping of reservoir properties from seismics and wells do not produce very certain estimates for large-scale properties. A fairly large uncertainty is to be accepted at the onset of injection. Figure 2 shows a reservoir outcrop in southern England (Bridport sands) that illustrate how reservoir heterogeneities might be distributed.

Fig. 2. – Picture from the Bridport Sand, UK, illustrating sandstone heterogeneity.

The local flow properties (permeability) are important, and the larger-scale consequence of them may be even more critical. The largest challenge for effective large-scale CO_2 storage is probably the displacement of the water that is occupying the sediments prior to injection. This displacement has to take place at a much larger scale than the reservoir itself, and the time factor associated with the displacement is much shorter than for most other natural flow processes.

The need for effective fluid displacement is an important issue, when a storage reservoir is to be used at a capacity utilization scale of 10^2 to 10^3 times that of present day operations. In the case of a closed reservoir system, where no water displacement can take place, only 1–4% of the pore space can be effectively used for CO_2 storage. In the closed system case, only the compressibility of water and gas can create extra space for injected fluids. A consequence of this is that large-scale storages must either rely on very large open system reservoirs with excellent flow properties also laterally outside the reservoir, or alternatively the water displacement can be achieved by concomitant water production from wells at a distance from the CO_2 injection wells. This will add some cost to storage operations, but it will significantly increase the effective storage capacity, and at the same time reduce the risk for pressure build up and vertical leakage.

One of the reasons why pore geometry and flow properties show such large variations is that reservoir sediments are transformed by compaction, mineral reactions and recrystallization during burial in the subsurface. Figure 3 is a thin-section micrograph of a sandstone sample from a deeply buried reservoir sandstone. A very characteristic mixture of very large and very small pores, with generally very narrow pore throats, is a common feature of a pore geometry that has been altered by mineral dissolution and reprecipitation. The large pores are secondary, and have been formed by mineral dissolution, while the small pores have been diminished by mechanical compaction.

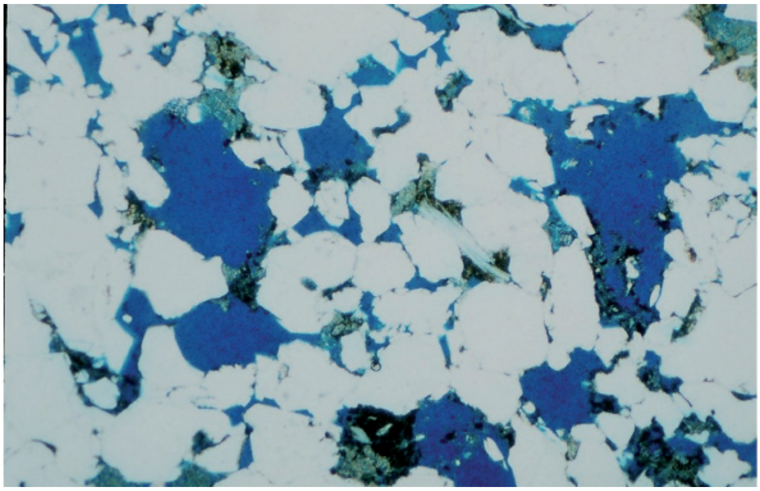

Fig. 3. – Deeply buried sandstone dominated by secondary porosity.

The porosity of this sample is fairly high, but the permeability has been greatly reduced by secondary burial processes. An extreme example of this effect is illustrated in fig. 4 and fig. 5, which are taken from the Snøhvit CO_2 pilot. The present depth of this reservoir is about 2.5 km, but it was buried much deeper in the past. Figure 4 shows very different pore geometries of two sandstone samples that were taken very close to each other.

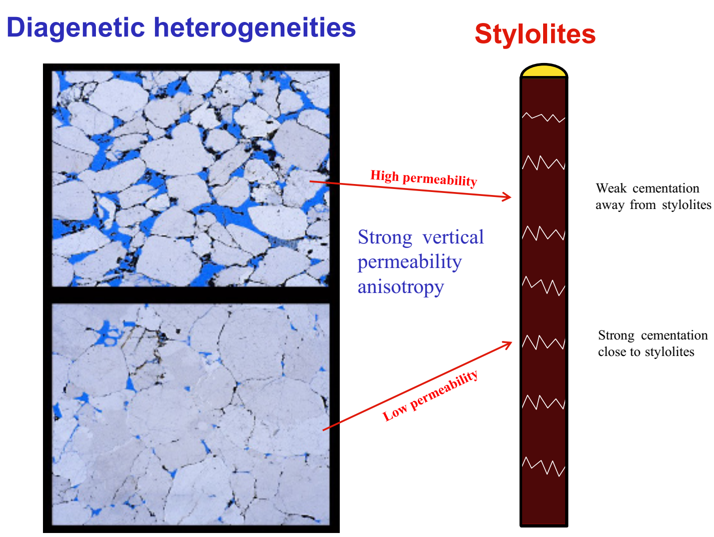

Fig. 4. – Thin-section micrograph images showing strong contrast in cementation, porosity and permeability between neighbouring samples.

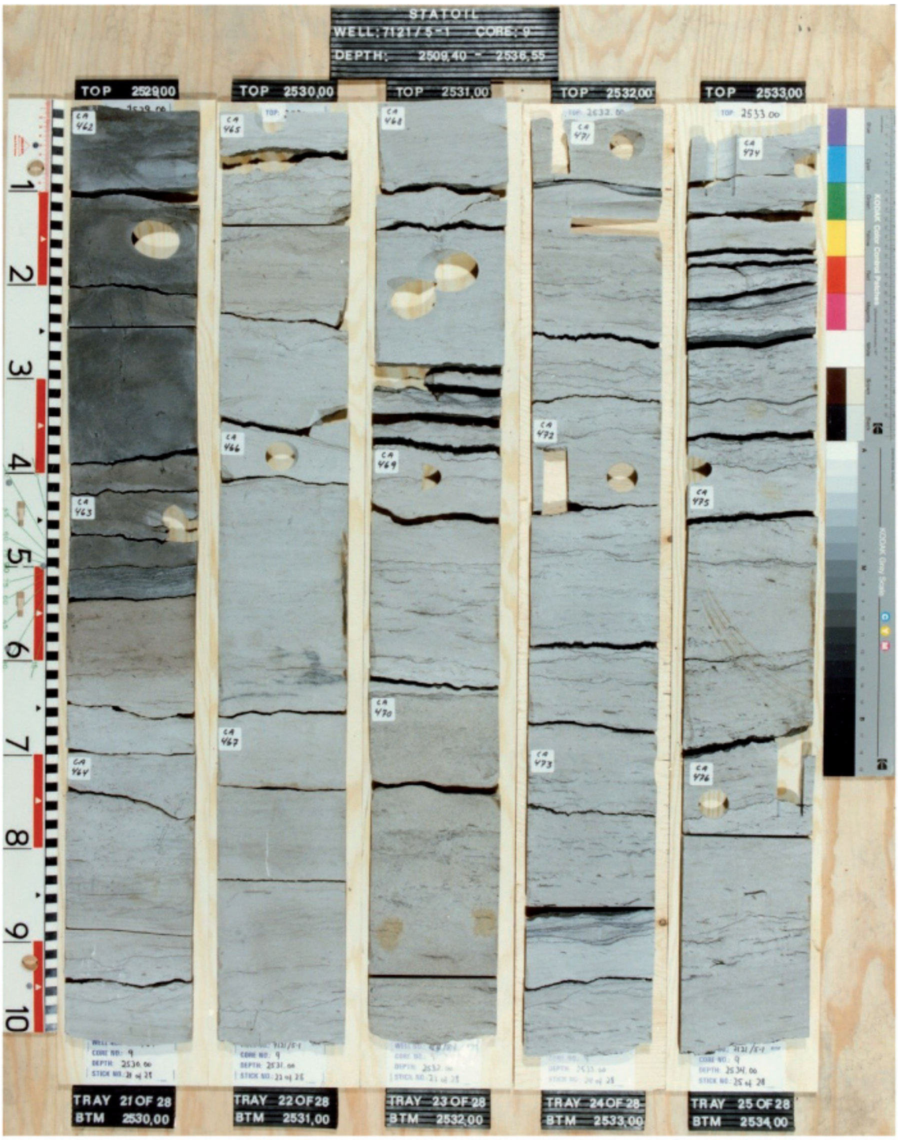

Fig. 5. – Picture of cores from the Snøhvit CO_2 pilot reservoir, where the core is segmented at the position of the stylolites (see text for more explanation).

The two images show that diagenetic effcts are not evenly distributed. Certain intervals may be much more strongly affected than others.

The zones of low porosity are caused by a process called stylolitization, which may be developed in both sandstones and limestones. Very strong dissolution and subsequent reprecipitation of cement in the close vicinity to the dissolution zones is very common in deeply buried sediments, as in this Snøhvit example. Snøhvit has experienced consider-

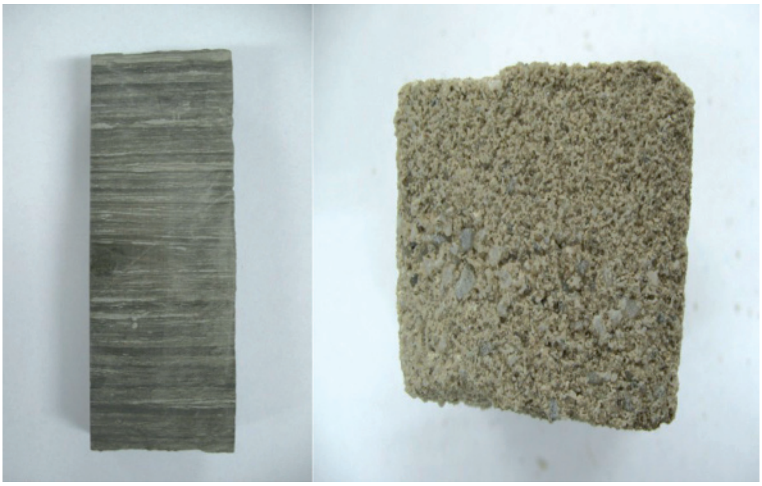

Fig. 6. – Typical shale caprock (left) and reservoir sandstone.

able CO_2 injection problems, and the uneven distribution of quartz cement in the sandstones may be one of the most important factors that have caused the injection problems.

Very much of what is discussed above can also be said about the variation in sealing properties of caprocks and overburdens above possible storage reservoirs. Sealing sediments are in general 5–10 orders of magnitude less permeable than reservoir sediments, but the variation of bed properties and inherent structure is very large, and the mapping of the overburden flow or sealing properties is even more uncertain than for reservoirs. This is mainly due to the fact that core material is very rarely taken from sealing sediments. Figure 6 shows a typical reservoir sandstone and a typical shale caprock, for comparison. Shales and claystones are the most common sealing sediment types, but also evaporates and carbonates may have excellent sealing properties. Carbonates are however very rigid sediments that commonly develop a large amount of fractures, so their sealing properties may show very large variation. Fractured carbonates with extremely low matrix permeability may actually be excellent reservoirs, if they contain a sufficient number of well-connected fractures.

The overall sealing properties of caprock and overburden sediment sequences is a complicated composite of all the individual seal elements that together constitutes the seal. Figure 7 is a schematic overview of the most important seal elements, including the injection wellbore. The sealing efficiency is in many ways a question about the presence or not of continuous pre-existing pathways with a significantly higher permeability than the bulk sediment package, and also the strength of the sediments to withstand the extra fluid pressure induced by the CO_2 injection.

How effectively the reservoir water is displaced from the reservoir through lateral flow in sediments with reservoir properties, will also be critical for the seal efficiency. If fluid pressure cannot be dissipated laterally, there will be an enhanced risk for vertically oriented deformation (fracturing) of the caprock and overburden sediments.

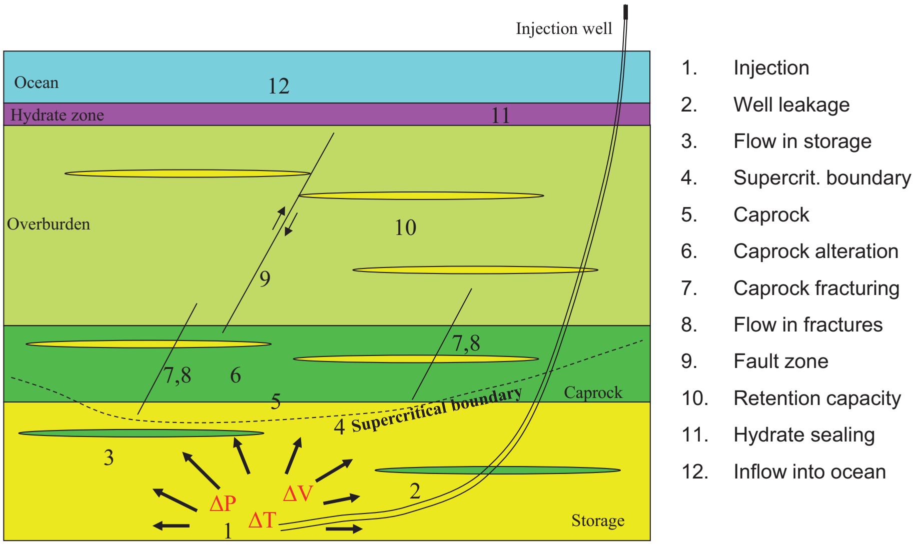

Fig. 7. – Schematic diagram for a seal sequence concept (see text).

Since caprock and overburden sediments are very rarely cored, the study of outcrops is the preferred method to understand the seal sequence concept. Active natural leakage of CO_2 at a rate that is comparable with CO_2 injection rates is very hard to find. The best analogue to a large magnitude leakage event is to study outcrops where extensive leakage of hydrocarbons has occurred. The Basque-Cantabrian Basin in NW Spain is one such area where high flux leakage can be studied at very good outcrop locations. Hydrocarbons leave traces of their leakage paths, which are very easy to observe, due to extensive staining of heavy black oil.

Figure 8 is a picture of a limestone quarry in Alsasua, where oil is being trapped in large pores, and has been migrating in large fractures, which are now mineralized. When a new part of the quarry is blasted, fresh oil is released, and the patterns of migration and trapping can be studied in detail. Figure 9 shows a large calcite cemented fracture in this quarry, and fig. 10 is a close view of the same cemented fracture. Figure 11 shows a thin-section micrograph from a similar vein sample from the Maestu quarry. The fracture has been filled with bitumen and calcite cement, and we have been able to count up to 20 generations of cement. Observation of fluid inclusions in the various growth bands show that the fluids that have circulated in the fractures over time has changed considerably, testifying to the longevity of the fracturing-cementation cycles.

The study of precipitated minerals in fractures in the Basque Cantabrian Basin has demonstrated that fracturing and subsequent closing of the fractures by carbonate cements is a multicycle process, which facilitates the throughput (leakage) of very large fluid volumes through the fractures over time. The learning from these field observations is that it is imperative to keep the injection pressure under control in CO_2 storage operations, so that the fracture pressure of the sealing lithologies is not exceeded.

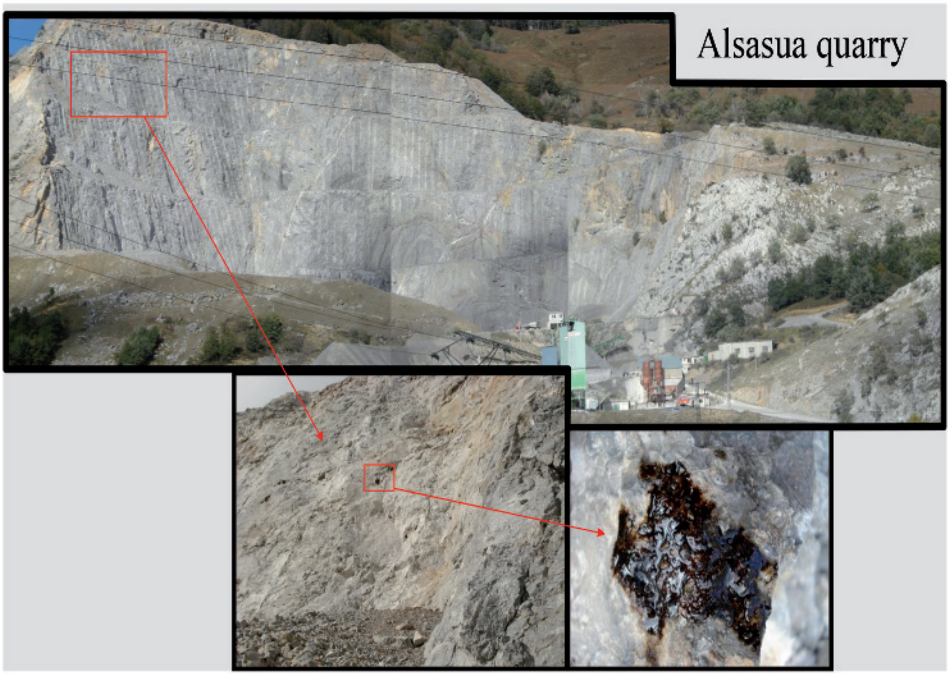

Fig. 8. – Picture from the Alsasua quarry limestones, where migrating oil has been trapped.

Figure 12 shows a picture of a porous sandstone that has been heavily impregnated with bitumen, as a result of major regional hydrocarbon leakage. The leakage was probably caused by the strong deformation of the Basque-Cantabrian Basin in connection with the strong folding that influenced the sediments during the formation of the Pyrenean mountain chain. The extensive bitumen impregnation demonstrates that overburden sediments have an extremely large capacity to act as secondary reservoirs, and thereby reduce or completely stop fluids from reaching all the way up to the surface. We expect that CO_2 seals will act in very much the same way. The seal sequence will thus represent a very important buffer to prevent CO_2 from reaching the surface, if some leakage into the seal should happen. In order to estimate leakage risks quantitatively, future studies should aim at the quantification of the CO_2 retention capacities of seal sediments.

3. – Drilling and well integrity

Wells are risk objects in relation to CO_2 storage. Ideally the best thing would be to only drill one well for injection in areas where no other wells were existing. This may be very difficult in reality, because hydrocarbon exploration activity is very often located in the same area that is of interest for CO_2 storage, and also because there may be a need for more than one well in a CO_2 storage project. This may either be to enhance the

Fig. 9. – Large mineralized fractures in the Alsasua quarry.

Fig. 10. – Close view of large mineralized fracture in the Alsasua quarry.

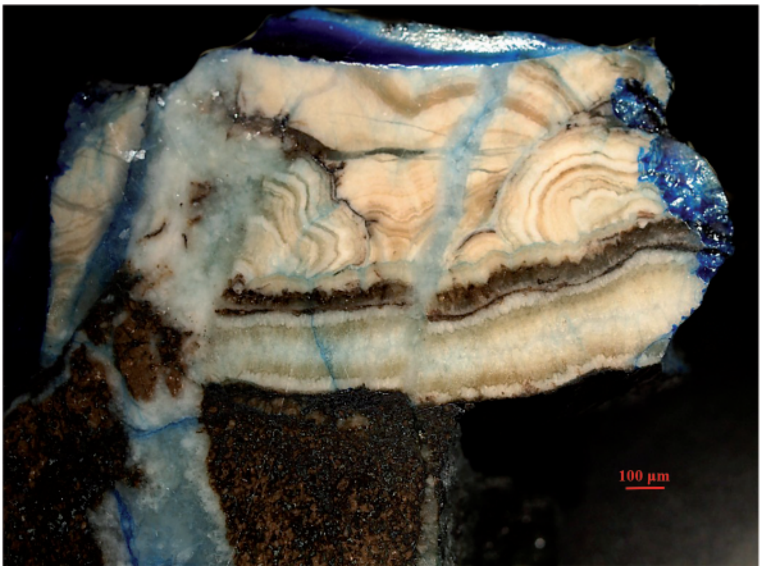

Fig. 11. – Calcite-bitumen cemented fracture filling from the Maestu quarry.

Fig. 12. – Atauri quarry tar sands, showing oil trapping in seal sediments.

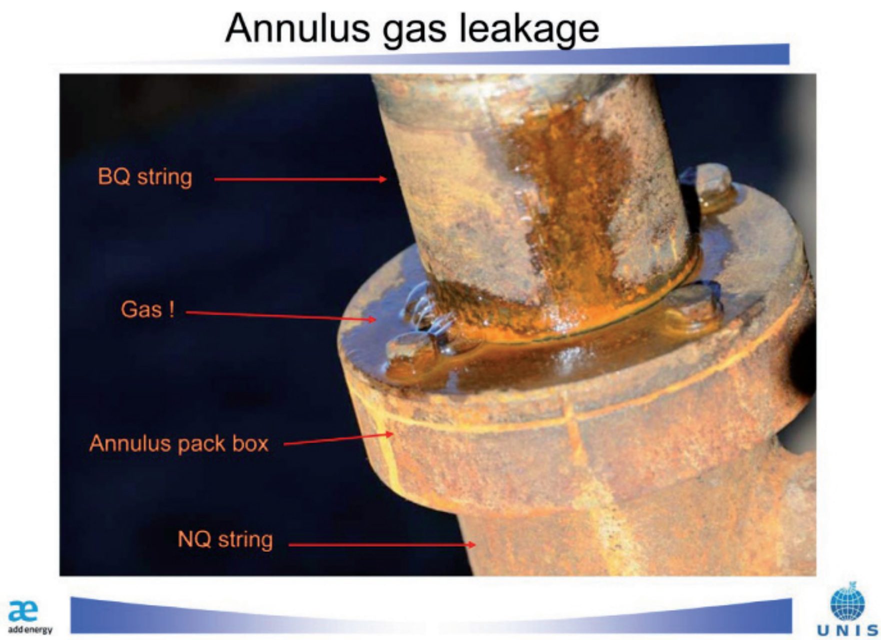

Fig. 13. – Wellhead showing gas bubbles at string junction.

injection capacity, or to distribute the injected CO_2 over a larger area, and it may also be necessary to drill water production wells for pressure release purposes in large-scale storage developments.

Well materials, the interfaces between these materials, and the sediments through which the well is drilled, are the critical elements in the assessment of wellbores as particular CO_2 leakage risk objects.

Figure 13 displays the topside of a well drilled at Svalbard for the Longyearbyen CO_2 storage pilot Project. We can observe a gas bubble between the BQ string and the annulus pack box. This shows that it may be very difficult to keep all the well materials completely gas tight. Another issue is the possible chemical (corrosive) degradation of both steel, cement and gasket material when they are exposed to CO_2 and water. Experience from a major long-term study of gas pressure build up in 40 wells feeding gas production in the Troll Field in the North Sea has shown that it is almost impossible to cement and complete wells effectively enough to prevent external fluid to migrate into the wellbore.

Figure 14 displays some results from cement-CO_2 batch experiments run at IFE. We have tested the reaction on cement for both wet and dry CO_2 (with and without water). We found that the dry CO_2 actually produced a more deeply penetrating carbonatization process than the wet CO_2, which quickly developed a protective impermeable cement coating close to the outer surface of the cylindrical cement plugs. The long-term effect on cement integrity and permeability, and on the material interfaces of the wellbore, is

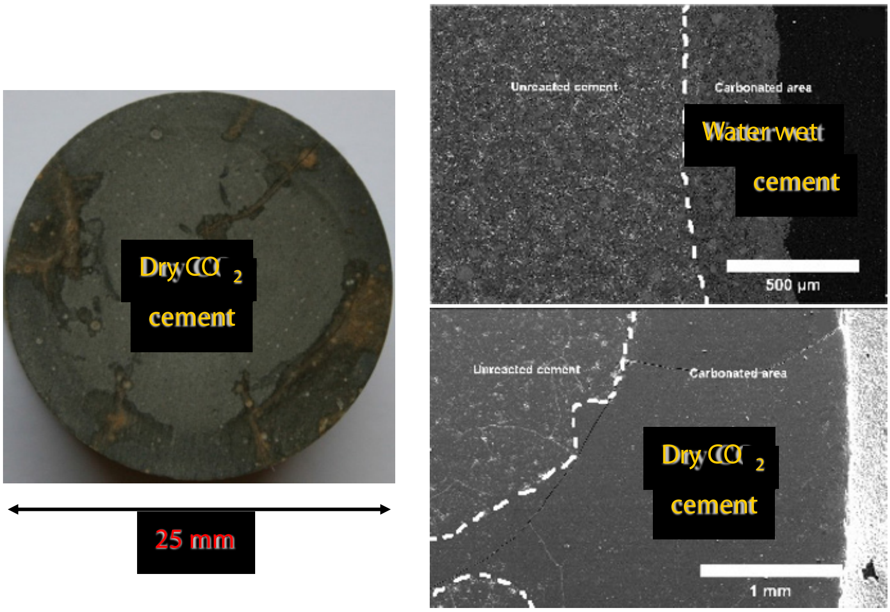

Fig. 14. – Cement batch experiments where well cement has been flooded by both dry and wet CO_2 (see text). The depth of penetration for the carbonatization reaction is larger in the dry case, because the wet flooding created a protective crust near the outer surface of the cement plug.

another area where quite a bit of research has been performed, but where also significance uncertainty remains.

4. – CO_2 properties

The PVT properties of pure CO_2 are very well constrained by experimental data, and are also very well implemented in various simulation models for CO_2 storage. When CO_2 is not pure, the data background for simulation is much less well constrained. H_2O, H_2, N_2, NO, N_2O, NH_3, CO, Ar, O_2, CH_4, C_2H_6, HCl, H_2S and SO_2 are some of the gas impurities that may occur at various stages of a CO_2 storage process. Some of these gases may be part of the gas due to inefficient gas separation during capture, while other gas components may be natural gas in the reservoir and caprock sediments.

Figure 15 shows the temperatures and pressures of the critical point (CP) for various gas components that may occur as impurities. It is clear from this diagram that the various gas components are very different with respect to CP, and the PVT properties of multicomponent gas mixtures may in some cases deviate strongly from that of pure CO_2. The depth and pressure of a planned CO_2 reservoir has been chosen to be sure that the CO_2 will occur as a dense fluid phase in order to use a minimum volume and

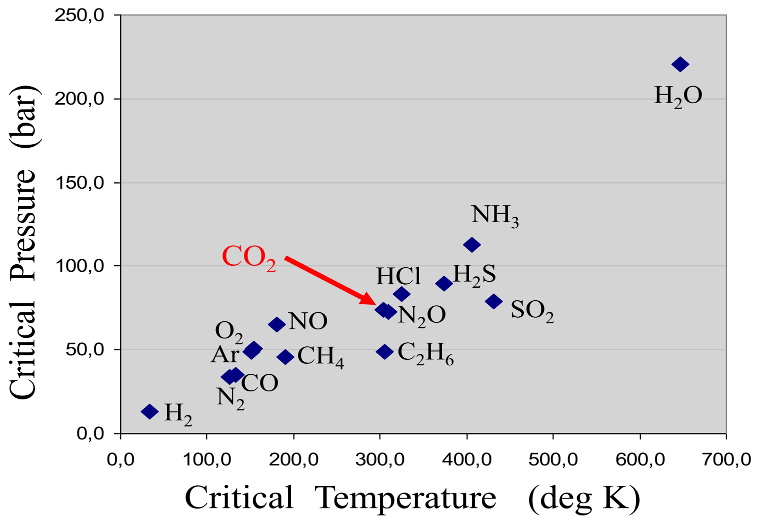

Fig. 15. – Critical temperatures and pressures for various possible gas impurities in CO_2 storages.

have a smallest possible buoyancy. Impure CO_2 may have several important implications during storage. The compressibility and density of the gas during injection may affect the injectivity as well as the fluid flow in the reservoir. The density will affect the storage capacity, the density will also affect the buoyancy, and therefore also the gas pressure, and finally impurities may also affect the reactivity of the injected gas.

CH_4 and some higher-molecular-weight hydrocarbon gases are omnipresent in almost all sediments. The contents are highly variable, from economic accumulations to very low values. Due to the very sparse data acquisition in sediments external to the reservoir, and the very few wells that are drilled in CO_2 storages, the knowledge of the content of natural gas distribution in the subsurface will remain very uncertain.

5. – Experiments

Unlike oil and gas production, where the continuous observation and measurements of the content and properties of produced fluids generate a huge amount of experience and data, the situation during CO_2 storage is significantly different with respect to data acquisition and operating experience. This introduces a need for complementary activities. Laboratory experiments coupled with predictive numerical simulation will therefore play a much more important role during CO_2 storage, as compared with conventional oil and gas production. Figure 16 shows a setup for a pressurized heated reaction system, where fluids are mixed in a first autoclave, exposed to reactions with solids in a second autoclave, and then exposed to new reaction conditions (changed pressure and/or temperature) in a third autoclave. We can in this setup investigate the mutual effects between fluids and solids at various conditions to simulate various storage operating con-

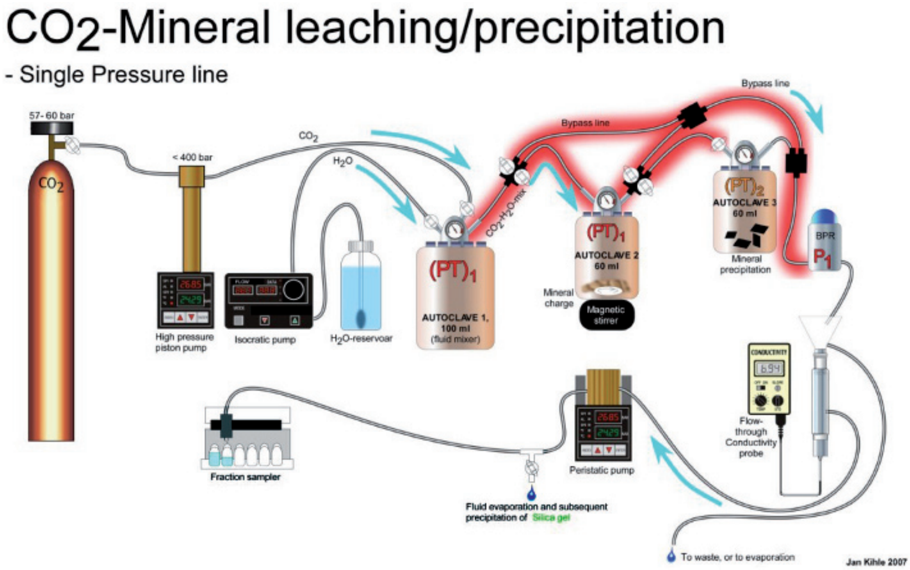

Fig. 16. – Setup for experiments to study the reactions between CO_2 and various solid materials (see text).

ditions. The data can then be matched in lab scale simulation. The largest challenge for this experiment-simulation activity is the upscaling of laboratory space and time dimensions to the reservoir operational scale.

Figure 17 shows an experimental example where a limestone plug, which initially contained an irregular pore size distribution (SEM backscatter; left-hand image), but which

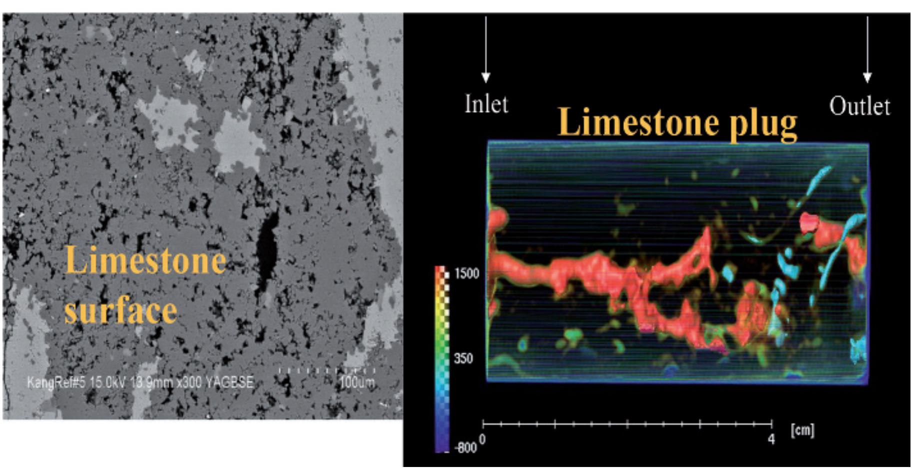

Fig. 17. – Limestone plug exposed to CO_2 injection (see text).

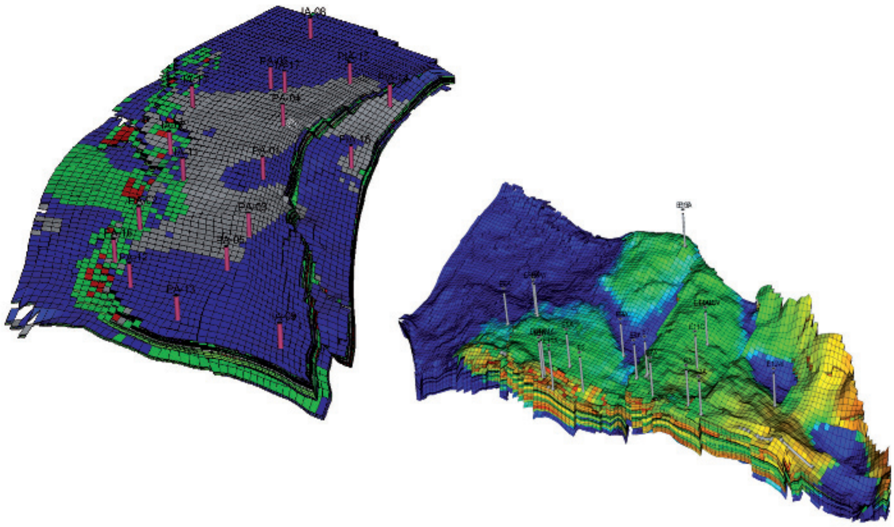

Fig. 18. – Illustration of a gridded reservoir with colour coding of the saturation of CO_2 after injection(red is high saturation; blue is low).

showed no evidence for channelized dissolution. After 10 days of flooding of the plug from left to right with CO_2 saturated hot water (200 °C, 300 bar), a very distinct "wormhole" developed in the plug (X-ray tomography; right-hand picture). Such enhancement and channelization can very strongly affect flow and/or sealing properties, even if the bulk change in porosity due to the reactions is very small.

6. – Simulation

Combined lab scale experiments and simulations is a very important predictive tool in CO_2 storage, but the usefulness depends on a correct upscaling methodology. Although a very detailed discretization into grid blocks is made in full scale reservoir modelling, the extrapolation of core based petrophysical data into undrilled distant grid blocks is a very uncertain exercise. Nevertheless, history matching of the observed "shape" of the CO_2 plume, based on remote monitoring tools (seismic, gravimetry, electromagnetics) can be used to improve the fit of the reservoir model as CO_2 injection is continuing over several years. Figure 18 illustrates the gridding of a reservoir model. The most significant shortcoming of this exercise is the lack of data on produced fluids, labelled by tracers from several injection wells, as is the normal situation during oil and gas production.

Figure 19 shows a plug scale (lab scale) simulation of dissolution fronts from the experimental "wormhole" development described in the text above, and illustrated in fig. 17.

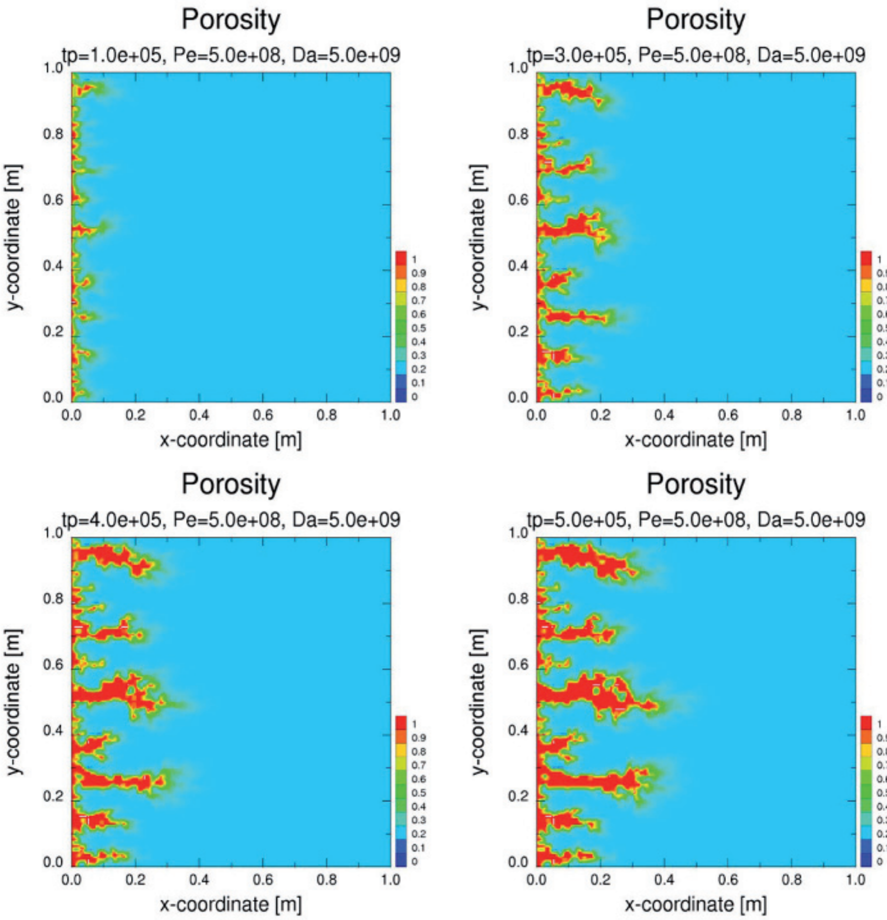

Fig. 19. – Illustration of a simulation of wormhole formation caused by CO_2 injection. The inlet of the plug is at the left-hand side of the diagrams.

7. – Is large-scale CO_2 storage feasible?

The discussion in this paper put focus on several issues that is presently not very well understood, as well as data that are lacking. Missing knowledge and data is however not likely to be a show stopper for CO_2 storage. If we compare the potential of CO_2 storage development in the future with the past history of oil and gas production, there is a clear parallel characterized by "learning by doing". The more than 150 years of experience of the oil industry has taught geologists and other scientists the best practise step by step, and at the same time increased our knowledge about the subsurface immensely. CO_2 storage is not starting at the same low baseline as the oil industry, but there are certain aspects of CO_2 storage and safety that needs to be developed by practical experience.

There are thus a few dominating requirements that need to be satisfied, if CO_2 storage is going to grow to the level of 8–9 Gt/year:

- that we get started as soon as possible;
- that we are flexible enough with respect to regulations to start the learning curve;
- that we realize that safe CO_2 storage on a large scale probably will require more wells and initially higher costs than we have been willing to admit up to now;
- but that, similarly to the oil industry, these costs are likely to drop substantially with the development of new technology;
- that for instance the need for more and cheaper wells will lead to a major breakthrough for new well technology;
- that this new game of "learning by doing" will lead to a greatly enhanced understanding of the subsurface;
- and that this new knowledge in its turn will lead to new development for new subsurface resources, and their environmentally friendly exploitation.

Safe large-scale CO_2 storage will in particular require extensive pressure control. Since oil and gas production is generally associated with decreasing pressure over time, CO_2 storage with increasing pressure is a new field of geological and technological experience that must be developed over time. Artificial fracturing of the subsurface is now increasingly being deployed for several different resources, such as

- shale gas,
- shale oil,
- geothermal energy,
- underground metal mining.

A greatly improved understanding of subsurface pressure control will be a major step forward for all types of environmentally friendly development of subsurface resources. We can foresee that new value chains will develop as a consequence of new ways of thinking about subsurface exploitation.

In summary, large-scale CO_2 storage is feasible, but it will require that politicians and other decision makers are brave enough to understand that it will require higher costs initially, and a new and more flexible way of thinking about subsurface resources and the environment. The reward in the other end is likely to be further economic growth based on fossil fuels, without having to compromise the climate problem and other environmental challenges.

Further reading

– Baines S. J. and Worden R.H. (Editors), *Geological Storage of Carbon Dioxide*, Vol **233** (Geological Society, London, Special publications) 2004, pp. 225–234.

– Thomas D. C. and Benson S. M. (Editors), *Carbon Dioxide Capture for Storage in Deep Geologic Formations*, Vol. **2** (Elsevier Ltd., Oxford, UK) 2005, pp. 1133–1141.

– *Greenhouse Gas Control Technologies*, Vol. **I** (Elsevier Ltd.) 2005. CEC, Directive of the European Parliament and of the Council on the geological storage of carbon dioxide, Impact Assessment, Commission of European Communities, Brussels, January 2008.

– *IPCC, Special Report on Carbon Capture and Storage*, Intergovernmental Panel on Climate Change (Geneva, Switzerland) 2005.

– Pearce J., Chadwick A., Bentham M., Holloway S. and Gary K., *Technology Status Review - Monitoring Technologies for the Geological Storage of CO_2*, Report No. COAL R285 DTI/PUB URN 05/1033 (Department of Trade and Industry, London, U.K.) 2005.