Benchmarking worldwide CO_2 saline aquifer injections

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Summary

Carbon Capture, Transport and Storage is a very active field of research, especially for the past decade. From the UK perspective, a commercially crucial aspect is the saline aquifer research, since there are predicted to be vast storage capacities in the sedimentary formations of the North Sea. The following report reviews the ongoing work on practical injections of CO_2 as research tests for storage projects and specifically focuses on industrial sized saline aquifer injections.

Investigated Projects

Injection projects for CO_2 have been underway for several years, and have become more numerous, with a trend to gradual size increase. It is now possible to undertake synthesis reviews on the learnings and progress to date including the recently published paper by Michael et al. (2010). In this report we have broadened the scope to include more projects as well as a more in-depth characterization.

In total we investigated 20 projects all around the world (Figure 1). North America is a very active region for CCS development, which is evidenced in the number of projects. We summarized 10 projects in the USA (MRCSP R.E. Burger, MRCSP East Bend, MRCSP Gaylord, Frio, WESTCARB Cholla, WESTCARB Rosetta, SECARB Escatawpa, SECARB Cranfield, MGSC Decatur and Rangely) and two projects in Canada (PCOR Zama and Weyburn). Europe is another region with a significant number of projects. In this report we characterized five of them, including two onshore projects (Ketzin in Germany and Lacq in France) as well as three offshore projects (K12-B and Sleipner on the North Sea and Snohvit on the Barents Sea). Other interesting projects we looked at are Australian offshore project Gorgon, Japanese offshore Nagaoka and onshore In Salah in Algeria.

Figure 1. Location of all investigated projects (2010 Google – Map data).

Technical Tests and Industrial Projects

For the purposes of this report we looked at current or completed projects that are particularly important to the development of the injection technology into saline aquifers. We looked both at demonstration and small scale projects, since these are the early indicators of the feasibility of a given technology and several of the industrial scale projects were based on these initial results. We also present a review of the industrial sized projects, the ones that actually have a real potential in mitigating CO_2 emissions.

Table 1 lists all the summarized projects with the estimated total CO_2 storage capacity. The large projects have industrial feasibility (grey) and the smaller ones are there mostly for technical development or testing the injectivity into a given rock formation.

Table 1. Planned total storage capacities of CO_2 in the 20 investigated projects.

Project Name	**Total Estimated CO_2 Storage Capacity**
MRCSP R.E. Burger	0
MRCSP East Bend	1,000 t
Frio	1,600 t
WESTCARB Cholla	1,800 t
WESTCARB Rosetta	2,000 t
SECARB Escatawpa	2,750 t
Nagaoka	10,400 t
MRCSP Gaylord	60,000 t
Ketzin	60,000 t
Total Lacq	150,000 t
PCOR Zama	250,000 t
MGSC Decatur	1 Mt
SECARB Cranfield	2.1 Mt
K12-B	8 Mt
In Salah	17 Mt
Weyburn	20 Mt
Snohvit	23 Mt
Sleipner	25 Mt
Rangely	26 Mt
Gorgon	129 Mt

In our analysis we included the Frio project, since it was the first test upon which further development of CCS in the USA was based. We described two unsuccessful technical tests: WESTCARB Cholla and MRCSP R.E. Burger. Both were cancelled, since the sites were shown to have too low injectivity. Interestingly, an injection to the same rock formation as in R.E. Burger at another MRCSP site (East Bend) was successful. This suggests the need to conduct small technical injection tests prior to large scale investments. The other WESTCARB project (Rosetta) was cancelled due to organizational, not technical, reasons.

SECARB Escatawpa was included since it is related (the same target rock formation) to the largely successful commercial operation in Cranfield. MRSCP Gaylord was selected because the target rock formation in this project is dolomite, which is an interesting exception (most of the storage reservoirs are sandstone). The interesting aspect of the PCOR Zama project are the pinnacle reef structures which will hold the injected CO_2. Ketzin, Total Lacq and Nagaoka show the European and Japanese approaches to CCS.

Aquifer Characteristics

Injection depth is one of the important characteristics of an injection site. It is correlated with the cost of injection. The shallower the reservoir, the more commercially feasible it is to inject CO_2. However, it cannot be too shallow since CO_2, the injected gas, should remain in the dense or supercritical state after the injection (at least 800 m of overlying rock is recommended). We observe that most of the projects are between 1200-2500 m deep (Figure 2).

Porosity is directly related to the static storage capacity, thus high porosity is a favourable characteristic. Most of the investigated cases have porosity over 10% (Figure 3).

High permeability is a much looked-for characteristic, since it is related to the attainable rate of injection. However, low permeability is not necessarily an indicator of an unsuccessful injection. The aquifers in successful commercial scale projects can have huge permeability valves (5000 mD at Sleipner) as well as a very low one (5 mD at In Salah) (Figure 4 and 5).

A better indicator of the potential success of an injection site than the permeability alone is the injectivity. It is defined as the product of the permeability of the aquifer and its thickness, with its units as Darcy-metre (Dm). In fact, some of the practices of aquifer selection, based on experience of methane gas injection and storage (TNO, Netherlands) suggest a minimum injectivity 0.25 Dm for an aquifer to be commercially feasible. All the investigated projects except for the two unsuccessful technical tests (WESTCARB Cholla and MRCSP R.E. Burger) pass this test (Figures 6 and 7).

Rate of injection is directly related to the number of wells in a given project. Most of the projects have just one well (particularly the small technical tests). The commercial projects have a larger number of wells to sustain a greater rate of injection and allow for a continuous injection of large quantities of CO_2. Thus, for instance, Gorgon is planning to inject at 8 points and In Salah has 3 wells. Large numbers of wells can help to achieve high rates of injection even in low permeability aquifers (Figure 8).

Pressure Issues

For storage, a well is drilled into the porous structure, and CO_2 (as a dense or supercritical liquid) is injected with enough pressure to overcome the existing static pressure within the porous formation. The pressure is closely monitored during the operational phase so it doesn’t exceed the fracture pressure of the rock. At this time pressure measurements at the well head are performed using a variety of conventional pressure sensors, including quartz gauges, strain gauges or optical sensors. The study has revealed that pressure management has been effectively planned or carried out in all the projects. Particularly interesting is a new method of water production and disposal into the oceans proposed for Gorgon project.

The MRCSP Appalachian project is the only other project that recorded a rapid pressure build up. It was due to lack of injectivity caused by very low porosity, low permeability and a thin reservoir unit.

Project Costs

The unsurprising pattern is that the cost of the small tests is in the order of tens of millions GBP, while the commercial projects are an order of magnitude more expensive (Figure 9). The interesting aspect is that while in the USA all projects are largely state funded, in Europe it is the industry groups that have provided the funding.

Transport

Pipelines, ships and tanker trucks are considered the most likely means of large-scale CO_2 transport. For 50% of the projects investigated (e.g. MRCSP R.E. Burger, Ketzin) tanker trucks were to convey the CO_2 from the production site to the injection site. Pipelines are the most prevalent means of bulk CO_2 transport and are a mature market technology in operation today. Pipes are used for all the commercial-scale projects (Sleipner, In Salah, Weyburn, and Gorgon). Bulk transport of CO_2 by ship takes place at a relatively minor scale, although recent work in Norway proposes that shipping may have a more general role in linking small sites of emission (< 1 Mt CO_2/year) to offshore storage hubs. This suggests that apart from cost, the mode of transportation can be linked to the amount of CO_2 being transported and the distance between the production and injection sites.

When evaluating the risk of CCS projects it is necessary that emissions from the systems used to transport captured CO_2 from the source to the injection site are calculated. These emissions may comprise losses due to equipment leaks, venting, and releases due to pipeline ruptures or other accidental releases during temporary storage.

Monitoring

Effective monitoring of CO_2 is a vital activity in the chain of CO_2 activities. A variety of techniques are already used to observe the behaviour of injected CO_2 at different phases of the operation. A range of monitoring techniques for leak detection has been developed and applied by the subsurface industries. These include seismic surveys (2D, 3D and 4D), vertical seismic profiling, cross-well seismic, electrical conductivity, microseismicity, passive seismic, soil gas sampling, detector array, eddy covariance, observation wells, time lapse microgravity, well temperature and pressure, well logs, tracers, ground water geochemistry, interferometer, satellite imaging, tilt meters. The type of monitoring programme depends on the site and the complexities depend on the degree of risk associated with the geological structure.

Gravimetry senses changes in the surface that are linked to difference in fluid density. Although it has a lower resolution than seismic survey data, it is faster to process and provides independent verification of the CO_2 plume location, as was shown in the Sleipner project. Similarly, time-lapse techniques can be used for detection of CO_2 pockets accumulating during or after the injection experiment. Interpretation models using either electromagnetic or well to surface resistivity logging are preferred, for example in In Salah, Nagaoka or MGSC Decatur.

Plume movement of CO_2 can also be monitored by measuring ground surface movements using a tiltmeter or from satellite images. Although satellite imaging is not common, radar interferometry (PSINSAR) has detected 8-10 mm deformation at the ground surface between 3 injection wells at In Salah. This method, however, is not always accurate as natural variations can occur due to cold weather or complications with cultural or vegetation effects. The satellite data is routinely available for land areas, but does not penetrate subsea. Another very common method is the use of oilfield well logs. This method has being successfully used in Frio and Nagaoka to detect and quantify CO_2 in the subsurface because of the high contrast between saline fluid and CO_2.

Seismic data, gravity surveys and a combination of more than two monitoring methods has proven effective for all investigated CCS projects. Multiple measurements using suitable methods are recommended to build the most accurate picture possible of the reaction and movement of the CO_2 in the reservoir. It is also apparent that the intensity and expense of monitoring in these pilot projects is much greater than would occur in routine projects after 2020.

Future

Obvious concerns have been expressed about the technical integrity of carbon storage in potential sites and the environmental and health risks associated with it. So what is the future of CO_2 storage? Projects like Weyburn and Sleipner have demonstrated that commercial quantities of CO_2 can be injected into the subsurface and the gas will not return to the surface. However, more work still needs to be done and the major barriers to broad deployment of CO_2 injection in saline formations addressed, in order to gain public and regulator acceptance for bulk CO_2 storage. Some of these barriers are listed below.

1. The scale of future operations is well beyond current experience, and is not easily simulated by computer models. “Learning by doing” is the only way to develop real expertise in storing large volumes of CO_2.
2. The majority of the projects summarized in this report, and specifically all the commercial CCS field sites (e.g. Sleipner, Snohvit, In Salah) targeted either onshore or offshore saline aquifers. The estimates of CO_2 storage capacity in saline aquifers are much higher than from oil and gas reservoirs. However, these estimates are subject to far greater uncertainty, due to lack of high resolution data.
3. Differences in geological formations cause the containment at some sites to be more certain than at others. For instance, the Midale project (which is an extension of Weyburn) demonstrated the possibility of containing CO_2 in a fractured reservoir. Shell’s confidence that this could work stemmed from the detailed knowledge of the regional geology. Thus, the importance of detailed research of potential conventional or ‘unconventional’ EOR and storage sites cannot be overemphasised. This will not only allow for identification of large previously ignored sites but will also lead to discovery of new scientifically based standards for monitoring future CCS operations and development of performance assessment methodologies necessary to demonstrate the long-term reliability of geological storage of CO_2 like the EU project CO_2ReMoVe.
4. Monitoring, measuring and verification (MMV) remains an area of development with a need for better tools to predict the capacity of reservoirs and the lateral and vertical movement of injected CO_2 over time. Especially since most of the technical or public concerns expressed are linked to the long term effects on storage areas and the possibility of either gradual or slow leakage. It is of utmost importance to prioritize continuous observations of the different injection sites. Technology know-how, appropriate techniques and experience from the oil and gas industries are expected to be very useful in addressing these issues.
5. Clear regulatory and legal protocols for injection of CO_2 into saline aquifers or elsewhere have to be developed.
6. The present drafting of European Union (EU) Directives on CO_2 storage lays onerous technical and financial conditions onto any subsurface developer. The quantity of acceptable leakage (if any) form an aquifer store is unclear. There appear to be different criteria of leakage for the ‘European Union – Emissions Trading Scheme’ (EU-ETS) and for the EU Directive. Providing geological confidence to enable prediction into the 30, 60, and 10,000 year futures will be very difficult, and will reply on predictive modelling of CO_2 movement and its effects.
7. Lastly, the public willingness to accept the storage of large volumes of CO_2 below ground remains uncertain. Education of all interested stakeholders is a critical issue for large-scale implementation.

In summary, the future of aquifer injection experiments for CCS in the UK is unclear in terms of funding and regulation. Unlike the US authorities, the UK government contributes comparatively little to the cost; most of the funding and the research and development comes from private sector companies. There is a huge difference between the volatile EU-emissions allowance and the cost of CO_2 abatement with CCS, and the private sector alone cannot bridge the gap in the foreseeable future. UK government therefore must deliver on two particular fronts to move CCS initiative forward (if the technology is to have a future beyond PowerPoint presentations); better economic incentives must be provided and the regulatory gridlock has to be overcome and coherent policy around the regulation and liability for CO_2 storage must be in place.

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Table 2. Saline aquifer CO_2 project characteristics.

	Aquifer depth [metres]	Daily CO_2 injection rate [tonnes per day]	Annual CO_2 injection rate [million tonnes per year]	Permeability [milliDarcies]	Porosity [%]	Aquifer thickness [metres]	Injectivity [Darcy-metres]	Estimated CO_2 storage capacity [million tonnes]	cost [million GB pounds]
MRCSP R.E. Burger	2170	0		0.08	3.20%	20	0.0016	0	12.14
MRCSP East Bend	1030	500		200	12%	100	20	0.001	12.14
Frio	1546	160		1500	30%	24	36	0.0016	
WESTCARB Cholla	1081	200		0	15%	200	0	0.0018	3.7
WESTCARB Rosetta	1052						0	0.002	3.98
SECARB Escatawpa	2595			1180	21%	64	75.52	0.00275	5.23
Nagaoka	1100	40		6	22.50%	60	0.36	0.0104	
MRCSP Gaylord	1061	600		22.4	12.50%	21	0.4704	0.06	12.14
Ketzin	650	100		750	23%	80	60	0.06	13.45
Total Lacq	4500		0.075	23	3%	121	2.783	0.15	53.79
PCOR Zama	1470	166	0.067	413	26%	343	141.659	0.25	
MGSC Decatur	1980	1000	0.33	225	15%	300	67.5	1	56.64
SECARB Cranfield	3140	4109	1.5	1000	20%	60	60	2.1	
K12-B	3750	1000	0.48	20	15%	350	7	8	
In Salah	1850	4000	1	5	17%	29	0.145	17	67.19
Weyburn	1418	5000	2.7	15	26%	30	0.45	20	27.55
Snohvit	2550	2000	0.75	450	13%	60	27	23	3493.92
Sleipner	1000	2800	1	5000	37%	250	1250	25	
Rangely	1950			8	12%	58	0.464	26	
Gorgon	2300	10000	4.9	25	20%	500	12.5	129	

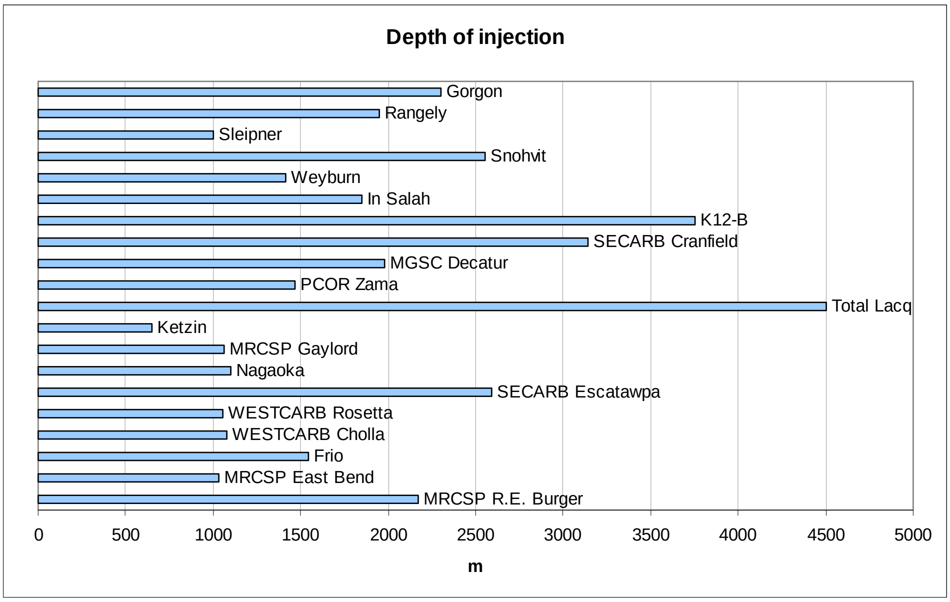

Figure 2. Depth of injection, in metres.

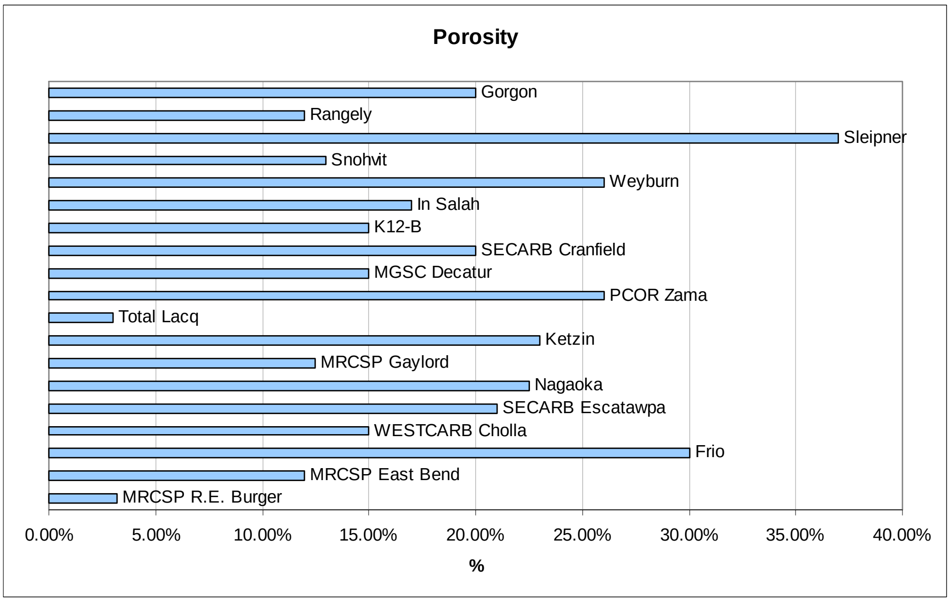

Figure 3. Porosity, %.

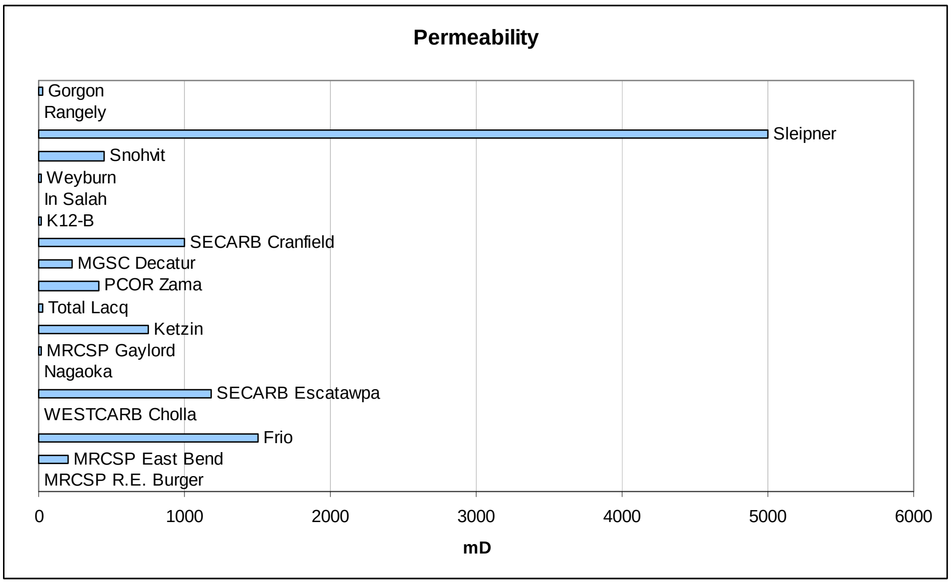

Figure 4. Permeability, milliDarcies.

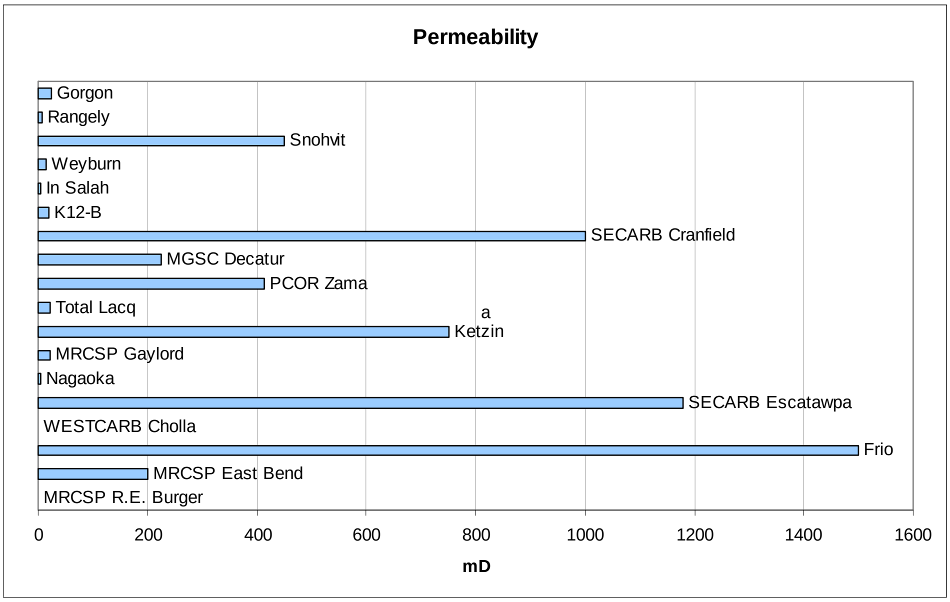

Figure 5. Permeability, milliDarcies (excluding Sleipner).

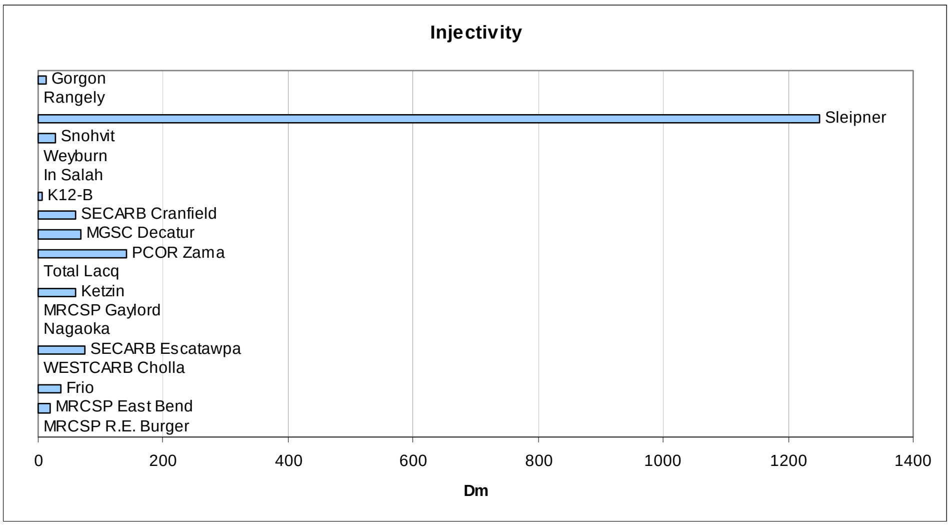

Figure 6. Injectivity, Darcy-metres.

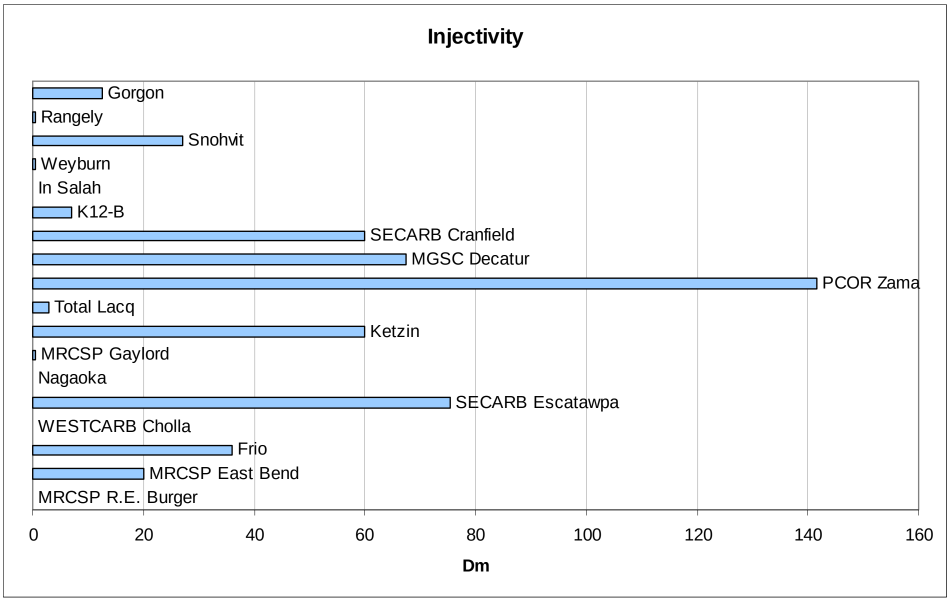

Figure 7. Injectivity, Darcy-metres (excluding Sleipner).

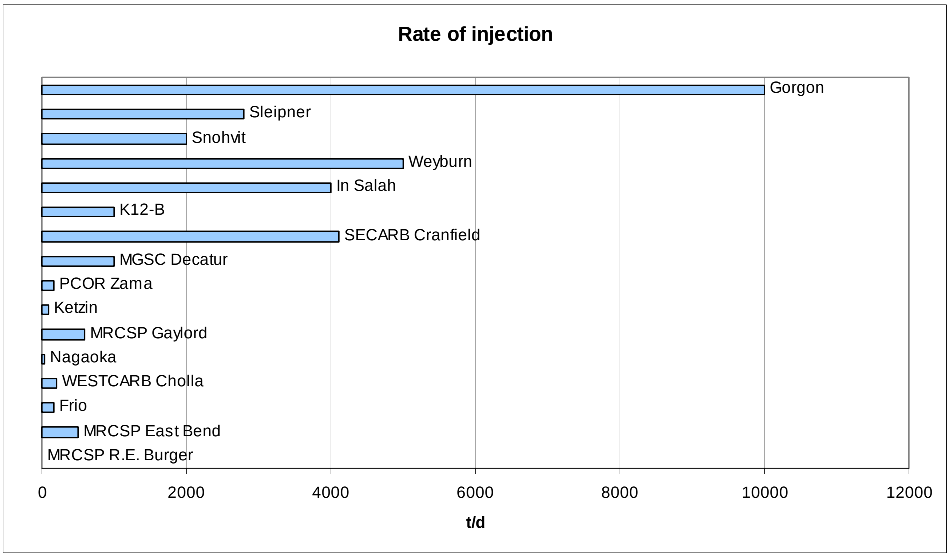

Figure 8. Daily rate of injection, tonnes CO_2 per day.

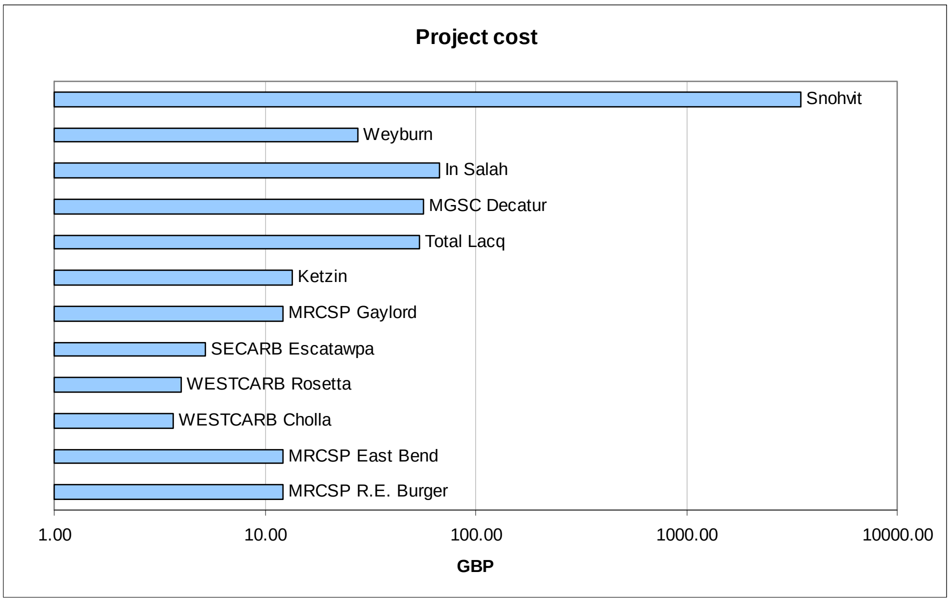

Figure 9. Project cost, million GB pounds.

MRCSP R.E. Burger

Partnership: Midwest Regional Carbon Sequestration Partnership (MRCSP)
Project Type: storage, onshore saline aquifer
Location: Shadyside, Ohio, USA
Partners: MRCSP
Start Date: 2008
Estimated Storage: nil
Project Website:
http://216.109.210.162/AppalachianBasin.aspx

Injection Rate	nil
Depth of Injection	2170 m
Reservoir Lithology	sandstone
Transport Method	pipeline
Porosity	3.2%
Permeability	0.001–0.08 mD
Formation and Age	Clinton Sandstone (Lower Silurian)
Thickness	20 m

Figure 10. Location and summary characteristics of the MRCSP R.E. Burger CO_2 injection site.

Overview

The Midwest Regional Carbon Sequestration Partnership (MRCSP) conducts tests to assess how effective storing CO_2 will be in the Midwestern region of the USA (Figure 10). One of the locations is R.E. Burger Plant in Shadyside, Ohio. CO_2 is injected into deep saline reservoirs, located 1.2 – 2.1 km underground, deep below drinking water supplies. Targets include the Oriskany, Clinton and Rose Run sandstones. The initial plan was to inject about 3,000 t of CO_2 over several months.

Site Characterisation

This site is located central to the Ohio River Valley, which is one of the major power generation corridors in the US. It is expected to facilitate access to other geological formations in the region that could have significant storage capacity (Clinton and Oriskany formations depicted in Figure 11). Initially it was also hoped that a pilot test of a developmental capture process could be linked to the injection test.

In early 2007 a borehole was drilled to a depth of 2500 m, where wireline logs and core samples were collected. The graphs in Figure 12 present porosity logs from the Oriskany and the Clinton sandstones. Porosity of the samples ranged between 2 and 10%, whereas rock samples from the Salina Formation had the highest porosity of all the layers. However, further injection tests were needed to confirm that these formations are indeed suitable for CO_2 injection.

Pre-injection

Before the injection the site was screened geologic data was compiled and the area was mapped based on the information then available. The monitoring, measurement and verification (MMV) feasibility was reviewed and a research plan was developed. The necessary federal and state permits were secured.

The site's potential for CO_2 injection was evaluated based on information available. In order to collect specific data the test well was drilled and core samples were taken to check porosity and permeability. The data was further used to develop pressure-response curves that helped estimate the injectivity. The results showed that rapid pressure buildup could be expected. Then, based on the site characterization, a well was completed. It made possible the injection into three potential reservoirs: the Clinton Sandstone, the Salina Formation and the Oriskany Sandstone.

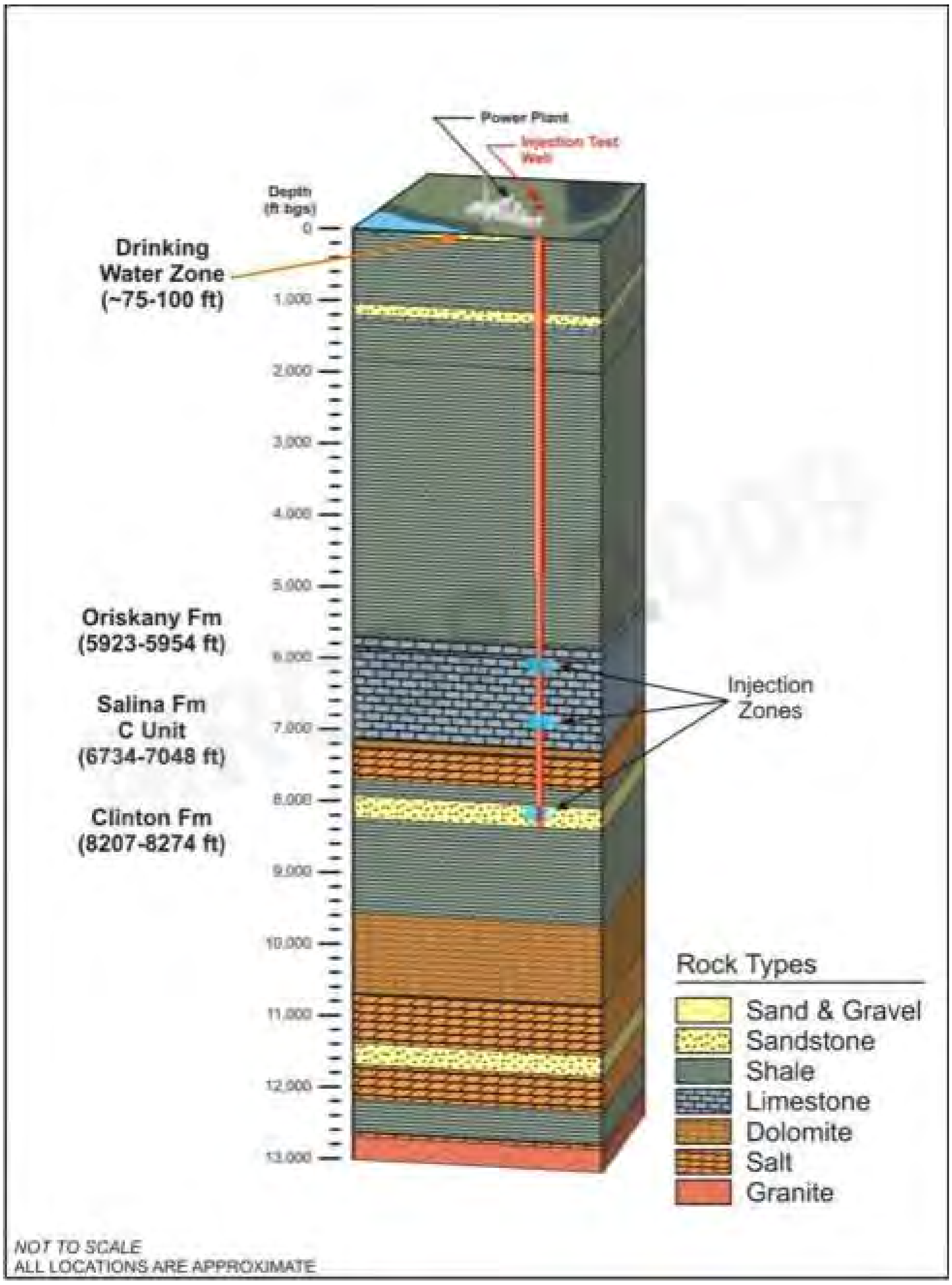

Figure 11. Sedimentary column at the injection site MRCSP R.E. Burger (from http://216.109.210.162/AppalachianBasin.aspx)

Injection

Injection started in September 2008, the goal was to inject up to 3,000 t of CO_2 in four to six weeks. CO_2 was delivered with tanker trucks, while the injection trailer served as a pump and a heater that ensured the CO_2 reached the correct pressure and temperature. After the injection was completed the data was intended to be analyzed and reviewed and the well closed and the area monitored.

Outlook and Issues

This test provided valuable insight into the Appalachian basin. A more detailed report is planned. The injection tests at the R.E. Burger showed that the three formations did not have sufficient porosity and permeability needed to complete the small-scale injection. In short, there was insufficient injectivity. Moreover, pressure in the well built up very quickly. However, this does not mean that other formations in the Appalachian Basin are also unsuitable; rock properties vary within the basin. Field injection tests are essential to check injection potential; characterization methods such as mud logging, rock core tests or wire line logging can only serve as an indicator of injectivity.

The experience gained during the project will be used in the region in the future. The project has improved mapping of the area and increased the general knowledge of the geology there.

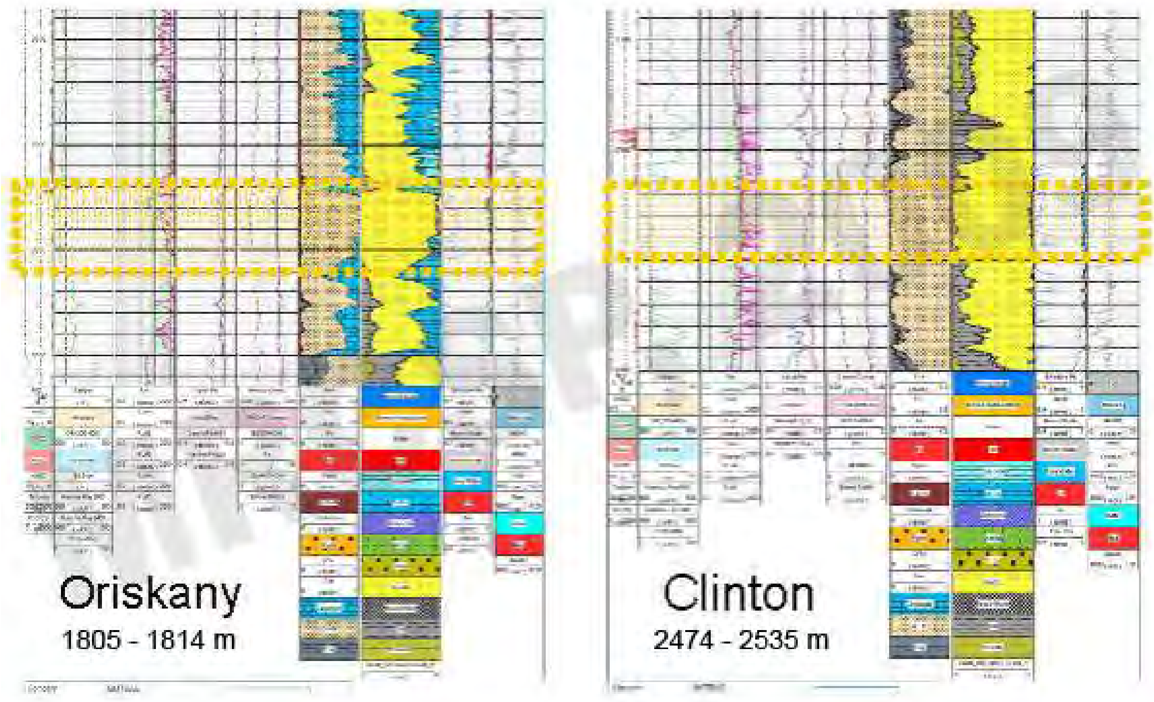

Figure 12. Porosity logs of the targeted sandstone formations Oriskany and Clinton (from http://216.109.210.162/AppalachianBasin.aspx).

References

MRCSP Site-Specific, R.E. Burger Field Demonstration Briefing, April 2006 http://216.109.210.162/userdata/appalachain%20basin/project%20briefing%20first%20energy%20projec.pdf, accessed 21.03.2010

R.E. Burger. MRCSP website. http://216.109.210.162/AppalachianBasin.aspx, accessed 21.03.2010

The Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC) database. http://www.co2crc.com.au/demo/appalachian.html, accessed 21.03.2010

MRCSP East Bend

Partnership: Midwest Regional Carbon Sequestration Partnership (MRCSP)
Project Type: storage, onshore saline aquifer
Location: Rabbit Hash, Kentucky, USA
Partners: MRCSP
Start Date: 2008
Estimated Storage: 1,000 t
Project Website:
http://216.109.210.162/CincinnatiArch.aspx

Injection Rate	500 t/day
Depth of Injection	1030 m
Reservoir Lithology	sandstone
Transport Method	13 km, tanker truck
Porosity	12%
Permeability	10-200 mD
Formation and Age	Mt. Simon Sandstone (Middle Cambrian)
Thickness	100 m

Figure 13. Location and summary characteristics of the MRCSP East Bend CO_2 injection site.

Overview

In this project MRCSP will store CO_2 produced by the East Bend Generating Station. Laterally extensive Mt. Simon Sandstone is a target formation of the deep saline aquifer. The reservoir is located at the depth of 1.2-2.1 km, well below the maximum depth of the water supplies (about 30 m). The team will analyse core samples and perform reservoir tests. If the site is deemed suitable for the injection, it will occur at a rate of about 500 t per day and the gas will be transported by a truck.

Site Characterisation

The sedimentary basin in the Cincinnati region provides a good opportunity for CO_2 sequestration. In this project the plan is to inject CO_2 into Mt. Simon Sandstone Formation. As we can see in Figure 14 the target injective formation is capped by a thick seal.

Pre-injection

In November 2006 MRCSP performed a 2-D seismic survey in cooperation with Appalachian Geophysical. In the summer of 2009, after receiving a drilling permit, the well was drilled and the core samples were analyzed. All these activities were accompanied by a comprehensive outreach program, including fact sheet preparation, website setup, holding open houses as well as in-person and e-mail briefings.

Injection

In September 2009 approximately 1,000 t of CO_2 was injected in the well. Monitoring during the injection included wireline tools, system pressure, temperature, brine geochemistry and groundwater measurements. CO_2 used in the project originated from a commercial source and was transported by standard delivery trucks.

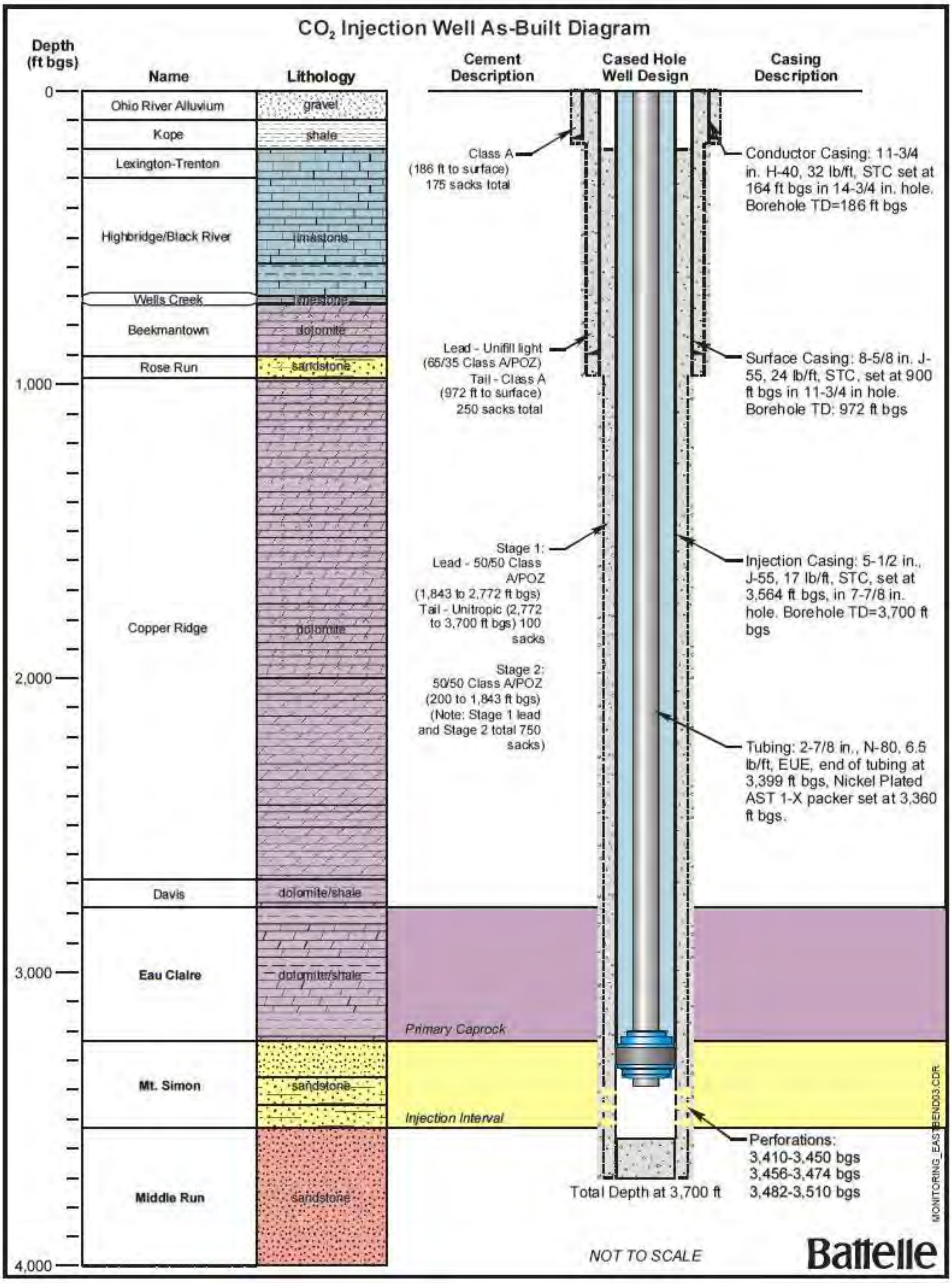

Figure 14. Sedimentary column at the MRCSP East Bend site of injection (from http://216.109.210.162/CincinnatiArch.aspx).

Monitoring

Over the next two years, the MRSCP team will monitor groundwater at the site to ensure that it is unaffected by the CO_2.

Outlook and Issues

The planned amount of 1,000 t of CO_2 was successfully injected in the Mt. Simon Sandstone. Preliminary results indicate that this formation is a good CO_2 store. Since it laterally extensive and spans much of the mid-west USA the storage capacity of Mt. Simon Sandstone is potentially commercially significant.

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The Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC) database. http://www.co2crc.com.au/demo/cincinnati.html, accessed on 21.03.2010.

Frio

Project Type: storage, onshore saline aquifer
Location: Liberty County, Texas, USA
Partners: Bureau of Economic Geology, University of Texas, Texas American Resources Company, Sandia Technologies, Transpectom, Lawrence Berkley National Laboratory, Lawrence Livermore National Laboratory, Oak Ridge National Laboratory, National Energy Technology Laboraratory, BP, Schlumberger
Start Date: 2002
Estimated Storage: 1,600 t
Project Website: http://www.beg.utexas.edu/environqlty/co2seq/fieldexperiment.htm

Injection Rate	160 t/day
Depth of Injection	1546 m
Reservoir Lithology	brine-bearing sandstone-shale
Transport Method	truck
Porosity	30%
Permeability	1500 mD
Formation and Age	Upper Frio Formation (Oligocene)
Thickness	24 m

Figure 15. Location and summary characteristics of the Frio CO_2 injection site.

Overview

The Frio Brine Experiment began in 2002, funded by the US DOE National Energy Technology Laboratory. This project takes place southeast of Houston, in the South Liberty oilfield (Figure 15). Extensive monitoring was conducted before the injection; wireline logging, baseline aqueous geochemistry, as well as vertical seismic profiling. The injection then started in October 2004, 1,600 t of CO_2 were injected over ten days. The movement of CO_2 was monitored during the injection and after it, to observe the post-injection migration. In summer 2006 the project moved on to its second phase.

Site Characterisation

The Frio Formation is characterized by low permeability Anahuac Shale – it is the upper seal for the Frio sands. Individual sand layers (A, B and C) are separated by shale layers which can serve as barriers to flow (Figure 16). In the South Liberty field there are many wells drilled for oil at depths around 2,400 m. They are very useful as a source of structural information about the field.

The C sand, saturated with brine, was the target for CO_2 storage. It is at a depth of 1,500 m, near the top of the Frio formation. To observe this layer, a new injection well was drilled from an existing well. The formation is compartmentalized by faults, several smaller intra-block faults also exist, with offsets that may juxtapose the B and C sands, enabling fluid flow between them.

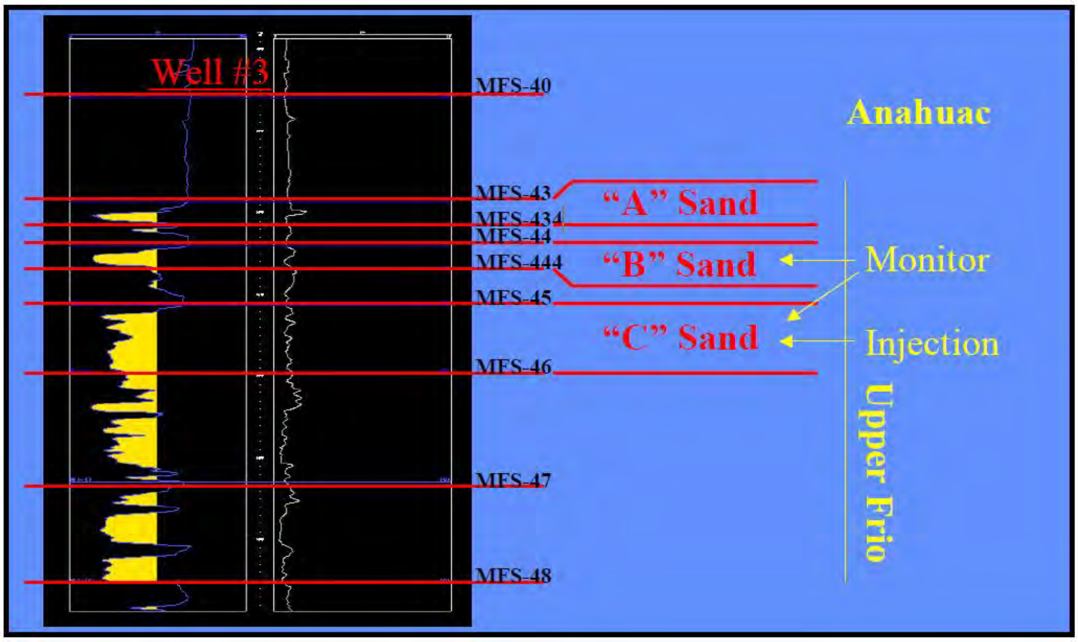

Figure 16. Stratigraphy at the Frio site (from Myer et al., 2003).

Pre-injection

Before injection the site was characterized using traditional methods: wireline logs; analysis of core samples; analysis of brine samples; pressure-transient analysis; and breakthrough curve analysis.

Injection

The injection took place over 10 days, 4-14 October 2004. The 1,600 t of CO_2 were injected into the highly permeable brine sandstone. Another important aim was to measure and monitor the subsurface CO_2 plume.

Monitoring

The goals of the monitoring in the Frio project were the following:

- demonstrate CO_2 injection;
- confirm models;
- test monitoring techniques.

Tracers used were noble gases: Ne; Ar; Kv; Xe; carbon and oxygen isotopes; and perfluorocarbon tracers (PFTs). Geophysical monitoring included Vertical Seismic Profiling (VSP), crosswell seismic, streaming potential and surface tilt analyses. Moreover, surface measurements were performed (water well sampling, passive seismic and CO_2 monitoring including soil gas and eddy flux).

The summary of the techniques used and the type of information gained is given in Table 3.

Table 3. Monitoring techniques used and information collected at the Frio CO_2 injection site (from Myer et al., 2003).

	New well logs	New well core	Seismic and electrical geophysics	Surface tilt	Pressure transient tests	Wellbore fluid sampling	Wellbore pressure	Tracers
Rocks type, thickness, dip	+	+	+	+				
Layer continuity			+		+	+	+	+
Faulting and fracturing	+	+	+	+	+	+	+	+
Porosity and permeability	+	+	+		+	+		+
Baseline mineral and fluid composition	+	+				+		
Evolution of fluid pressure			+	+	+	+	+	
Evolution of CO_2, brine saturation	+		+		+	+		+
Mineral dissolution, precipitation; fluid chemistry changes						+		+

Outlook and Issues

The project had four major objectives: to demonstrate that CO_2 can be injected into a brine formation without negative side effects; to use varied methods to measure distribution of the CO_2 injected; to test the validity of these methods; and gain more overall experience in CO_2 injection. Substantive progress has been made towards achieving these objectives.

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WESTCARB Cholla

Partnership: West Coast Regional Carbon Sequestration Partnership (WESTCARB)
Project Type: storage, onshore saline aquifer
Location: Cholla power plant, west of Holbrook, Arizona, USA
Partners: Arizona Public Service, Salt River Project, Tucson Electric Power, U.S. Department of Energy, California Energy Commission
Start Date: 2007
Estimated Storage: 2,000 t
Project Website:
http://www.westcarb.org/index.htm,
http://www.bki.com/westcarb/AZ_pilot.html

Injection Rate	50-200 t/day
Depth of Injection	1081 m
Reservoir Lithology	sandstone
Transport Method	truck
Porosity	15%
Permeability	too low to inject
Formation and Age	Naco and Martin formations (Devonian)
Thickness	200 m

Figure 17. Location and summary characteristics of the WESTCARB Cholla CO_2 injection site.

Overview

Phases I and II of this project determined the most promising saline aquifer and site for CO_2 storage. In Phase III 2,000 t of CO_2 were to be injected into the saline aquifer at the selected site near Holbrook, Arizona (Figure 17). Subsequently, the tracking of the movement and monitoring of the CO_2 plume would follow.

However, after drilling a well it was found that the permeability of the target formation is insufficient to warrant CO_2 injection at this location. Currently, other sites in the vicinity are considered for the CO_2 injection. Since other wells in the Colorado Plateau exhibit favourable permeabilities, this area remains a top candidate for CO_2 sequestration.

Site Characterisation

The Colorado Plateau in Arizona is underlain by a thick sequence of subhorizontal sedimentary formations having potential for storing and capping injected CO_2. The sandstone or carbonate reservoirs are found at depths ranging from 900 to 2300 m and are overlain by impermeable shales (Figure 18).

The Cholla site was selected based on the estimated potential of CO_2 storage and that the uppermost aquifer in this region is highly saline, which suggested that the underlying reservoirs are saline as well. The Devonian age Martin Formation and the Pennsylvanian Naco Formation were the targets of the injection effort (primary and secondary target, respectively). Figure 19 shows the observed geologic column as determined by drilling. Both target formations are characterized by sufficient depth to ensure that CO_2 would remain in the supercritical state after the injection and are capped by regionally extensive fine-grained formations. A significant factor in choosing the site was the ease of permit acquisition and the accessibility by paved roads.

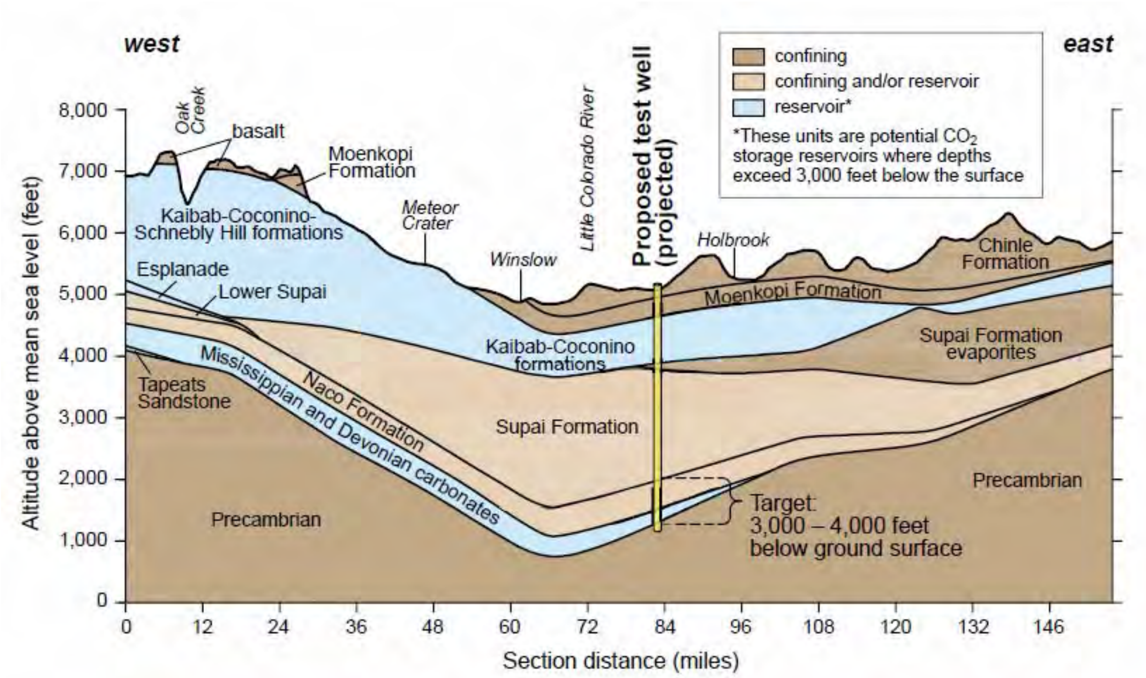

Figure 18. East-west regional schematic geologic cross-section of the WESTCARB CO_2 sequestration pilot project (from Shirley et al., 2009).

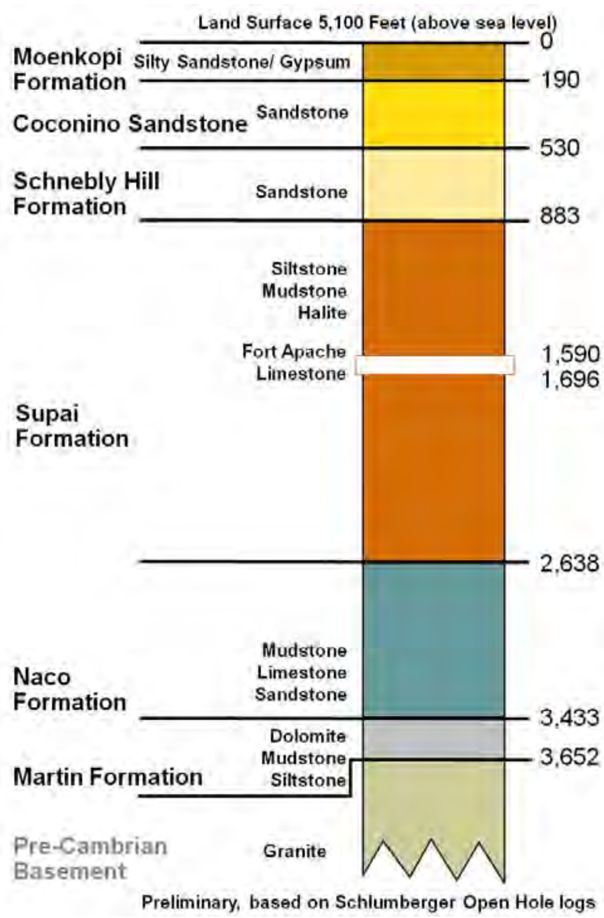

Figure 19. Well log at the WESTCARB Cholla test site (from Factsheet for Partnership Field Validation Test).

Pre-injection

The pre-injection phase of this project was split in two parts. Phase I included initial planning, geological characterization, and public outreach. The data investigated at this time were the sedimentary rock formations data and groundwater salinity. Much attention was paid to keeping the local community informed, which was achieved by meetings of the WESTCARB representatives with the interested community members.

In Phase II the site characterization, detailed planning and drilling of the well followed the initial preparations. The drilling had to be preceded by permit acquisition and was followed by testing to determine the suitability of the well for Phase III – the injection of CO_2. Data from boreholes were analyzed and the injection of CO_2 was modelled. In a period of about 30 days in August 2009 a well was drilled to the depth of 1174 m. The testing performed in August and September 2009 included extraction of formation fluid samples to ascertain salinity. Well logs and drill stem tests were conducted to obtain porosity and permeability when it was found that the permeability is insufficient to proceed to the injection phase.

Injection

Injection was contingent upon the findings of the Phase II. Unfortunately, the permeability of the target storage formation was too low to allow for the injection. Currently, this project has been reverted to Phase II.

Originally, the goal of Phase III was injecting 2,000 t of CO_2 and monitoring the behaviour of the plume after injection as well as its effect on the environment. Findings from this storage experiment are going to be extrapolated to estimate total CO_2 storage capacity of the Colorado Plateau of north-eastern Arizona. Interestingly, there are plans to extract the CO_2 from the well after the injection to obtain additional data.

Outlook and Issues

After finding unexpectedly low permeabilities in Phase II, Phase III of the project was redefined and the injection at the Cholla well was cancelled. The deadline for the selection and characterization of another injection site was November 2009, but at this date there is no information on the progress in that matter.

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WESTCARB Rosetta

Partnership: West Coast Regional Carbon Sequestration Partnership (WESTCARB)
Project Type: storage, onshore saline aquifer
Location: Rio Vista, California, USA
Partners: WESTCARB and C6 Resources, an affiliate of Shell Oil Company
Start Date: 2009
Estimated Storage: 2,000 t
Project Website:
http://www.westcarb.org/index.htm,
http://www.westcarb.org/Shell_geo_pilot.htm

Injection Rate	unknown
Depth of Injection	1052 m
Reservoir Lithology	sandstone
Transport Method	truck
Porosity	unknown
Permeability	unknown
Formation and Age	McCormick Sand (Upper Cretaceous)
Thickness	unknown

Figure 20. Location and summary characteristics of the WESTCARB Rosetta CO_2 injection site.

Overview

The West Coast Regional Carbon Sequestration Partnership (WESTCARB) Project was scheduled to begin in 2009 and involves two pilot tests. In the first test up to 2,000 t of CO_2 will be injected into a brine zone in the McCormick sand, which is very fine sandstone. Beneath the gas trap in the sand there is the saline zone, where two wells will be installed, a CO_2 injection and an observation well. The saline test will take place at the depth of 1037-1067 m.

Site Characterisation

The site chosen lies in the Southern Sacramento Valley Region of California. The targeted formation is the McCormick Sand, a very fine- to medium-grained, quartzitic sandstone (Figure 21). The depth of the injection was initially estimated as 1067-1098 m.

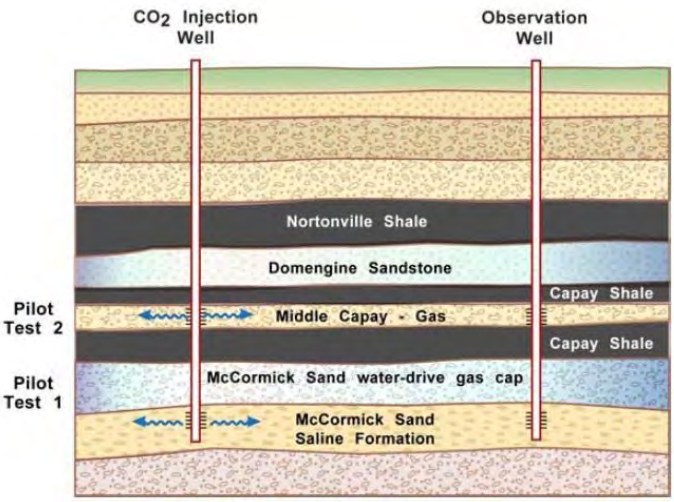

Figure 21. Typical geological cross-section showing stacked reservoir and the targeted sedimentary formations: McCormick Sand and Middle Capay Shale, WESTCARB Rosetta injection site (from Trautz et al., 2006).

Pre-injection

Before the injection, the wells will be logged and tested. Preliminary computer simulations have already been conducted to support the design of the tests. It is important to know how much CO_2 can be injected, and at what rate, as well as pressure and temperature changes during the injection. It is further important to decide on the methods of sampling and monitoring in the observation well.

Simulations have shown that around 1,800 t of CO_2 injected at a rate of 2 kg/s is needed to achieve the breakthrough of supercritical CO_2. This should take about 10 days. Far less CO_2 (1000 t injected at a rate of 1.2 kg/s) and time (a few days) is needed to achieve breakthrough of CO_2 in the 2-3 m thick Capay Shale.

Injection

This project was dropped, there were no actual injections.

Outlook and Issues

This project was apparently dropped by Rosetta Resources Inc. and was effectively cancelled. This may have been due to the proximity of a similar project, also into a low quality reservoir. However, there is a new project by WESTCARB in cooperation with Shell going on in the same area; Northern California CO_2 Reduction Project.

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SECARB Escatawpa

Partnership: Southeast Regional Carbon Sequestration Partnership (SECARB)
Project Type: storage, onshore saline aquifer
Location: Escatawpa, Mississippi, USA
Partners: SECARB, Bureau of Economic Geology (BEG)
Start Date: 2008
Estimated Storage: 2,750 t
Project Website: http://www.secarbon.org/

Injection Rate	unknown
Depth of Injection	2595 m
Reservoir Lithology	sandstone, conglomerate
Transport Method	unknown
Porosity	21%
Permeability	1180 mD
Formation and Age	L. Tuscaloosa Formation (Cretaceous)
Thickness	64 m

Figure 22. Location and summary characteristics of the SECARB Escatawpa CO_2 injection site.

Overview

This project aims to find and test saline aquifers suitable for CO_2 storage in the vicinity of power plants powered by coal along the coast of the Mississippi Gulf. The target formation here is the Cretaceous Lower Tuscaloosa Massive Sand Unit in Jackson County, Mississippi (Figure 22). In order to conduct the tests, the detailed maps were built and simulations were conducted to estimate injectivity and storage capacity. In the Mississippi Power Company Plant Daniel 3,000 t of CO_2 were injected at a depth of 2,620 m in October 2008. The wells for injection and observation were drilled already in March and April 2008.

Site Characterisation

Lower Tuscaloosa Massive Sand Unit has been chosen because it is a promising storage reservoir. The Tuscaloosa Massive Sandstone can be found along the entire Gulf of Mexico coast. Figure 23 shows a stratigraphic column of the region. In its upper section there is shale, and sand at the base, which also contains quartz sand. It is interpreted as fluvial and deltaic sedimentation, deposited when sea level was high around the globe. This formation could store half of the CO_2 produced in the SECARB region during a whole century. It is part of a larger formation, the Gulf Coast Wedge. Some of the largest saline sinks in the USA are to be found in this region. The tests conducted in the Lower Tuscaloosa Massive Sandstone will determine whether other sedimentary strata in the Gulf Coast Wedge are also suitable for CO_2 storag.

Pre-injection and Injection

Before the injection there was a pilot study, when two wells (an injection and observation well) were drilled at depths over 2900 m. The injection well was drilled with a Class 5 Underground Injection Control (UIC) permit. Such an application was not submitted for the observation well. The test was widely monitored; a monitoring, verification and accounting (MVA) program ensured safety for the environment as well as to trace how CO_2 migrated within the formation. Soil flux, tracers and groundwater quality were scrutinized. There was also an outreach program. The drilling started in February 2008 and both wells were cemented in early April. Then geophysical logs, cores and fluid samples were analyzed. In October 2008 about 3,020 t of CO_2 were injected into the formation.

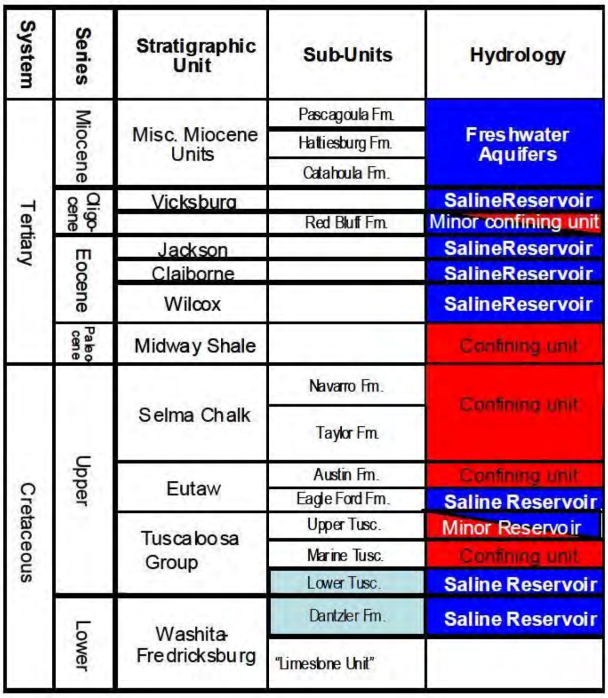

Figure 23. Type stratigraphic column of the Gulf Coast Region, USA (from Phase II factsheet found at http://www.secarbon.org/)

Monitoring

In order to monitor the movement of CO_2, time-lapse vertical seismic profiles (VSP) were used, together with pulsed-neutron logging. However, the results were inconclusive. Further methods to ensure safety included soil flux measurement and its comparison with pre-injection baseline, as well as tagging CO_2 with perfluorocarbon tracers (PFT), which were monitored. Finally, wellhead and down hole pressure were measured to ensure well integrity.

Outlook and Issues

The injection well was found to be fit for continued use. Monitoring tasks were ended and the final report is currently in progress.

References

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Nagaoka

Partnership: RITE and ENAA
Project Type: storage, onshore saline aquifer
Location: Nagaoka, Niigata, Japan
Partners: Ministry of Economy, Trade and Industry, Research Institute of Innovative Technology for the Earth, Engineering Advancement Association, Waseda University, Keio University, Ibaragi University. National Institute of Advanced Industrial Science and Technology
Time Scale: Start date: 2002, Injection: Jul 03-Jan 05
Estimated Storage: 10,400 t
Project Website: http://www.rite.or.jp/English/lab/geological/overview.html

Injection Rate	20-40 t/day
Depth of Injection	1230 m
Reservoir Lithology	sandstone
Transport Method	overland lorries in liquefied state
Porosity	22.5%
Permeability	1-7 mD
Formation and Age	Haizume Formation (Plio-Pleistocene)
Thickness	60 m (12 m target)

Figure 24. Location and summary characteristics of the Nagaoka CO_2 injection site.

Overview

The 'Research and Development of Underground Storage for Carbon Dioxide' project located at Nagaoka, Niigata Prefecture, Japan (Figure 24), is run by the Research Institute of Innovative Technology for the Earth (RITE) in co-operation with the Engineering Advancement Association of Japan (ENAA). Injection into an onshore saline aquifer commenced in July 2003 and ended in January 2005 after around 10400 tonnes of CO_2 had been injected in the supercritical state. To improve the understanding of CO_2 behaviour in the reservoir a number of techniques were used during injection. These included a series of field surveys and measurements: cross well seismic tomography; well logging; reservoir formation pressure and temperature measurements; and micro-seismicity monitoring (Xue et al., 2006).

Site Characterisation

The injection site is located at the South Nagoaka Gas Field, 200 km north of Tokyo in Niigata Prefecture, owned by the Teikoku Oil Co. Ltd. Located 12 km inland, the stratigraphy surrounding the injection site was first quantified for hydrocarbon prospecting. The region around the test site consists of three major sedimentary units known as the Nishiyama, Haizume and Uonoma formations which range from Neogene to early Quaternary in age. These units have been gently folded into anticline-syncline pairs in a NNE-SSW trend. In 2000, an injection well was drilled to a depth of 1230 m, which would allow for the acquisition of core samples and geophysical logs and for the geophysical characteristics of the target aquifer and caprock to be analysed. The target reservoir lies within the wave-dominated delta facies deposits of the Haizume Formation. A 12 m thick unit of high porosity sand within the 60 m aquifer unit of the Haizume Formation has been targeted for the injection of CO_2. This unit lies at the depth of around 1100 m and has an average porosity of 22.5% (Mito et al., 2008). Permeabilities within the aquifer range from 1 mD to several tens of mD within the target 12m-thick zone. The caprock to the reservoir is formed by a 130-150 m thick mudstone, which also forms part of the Haizume reservoir. The sealing properties of the caprock (confirmed by the geophysical logging), its thickness and regional extent was one of the main factors for selection of the test site. The reservoir and caprock are part of a monoclinal structure and dip at 15^0 towards the ESE (Kikuta et al., 2005).

Pre-injection

Characterisation of the target reservoir, core samples and geophysical analysis were used to inform the location of the three observation wells. In 2001 and 2002 the three wells were drilled to depths of 1319 m, 1270 m and 1322 m. This configuration can be seen in Figure 25.

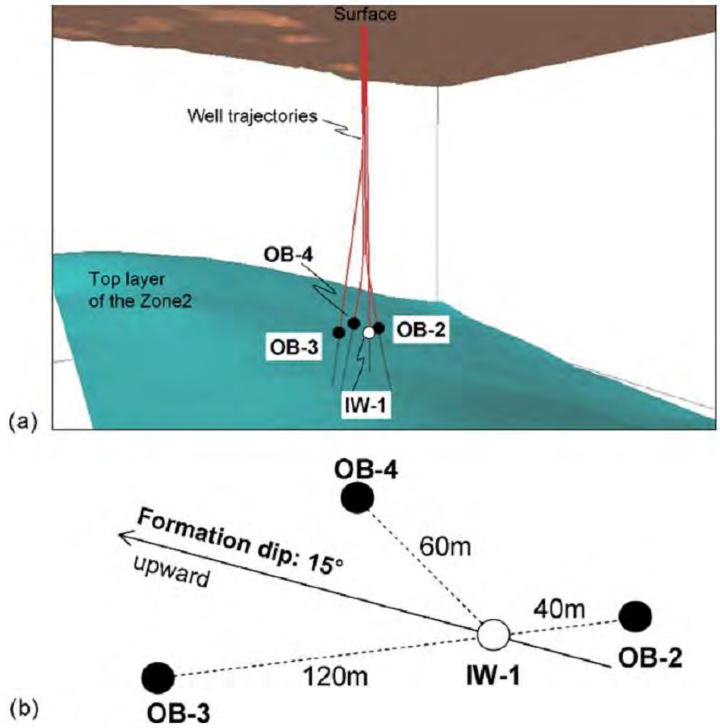

Figure 25. (a) Configuration of the injection well (IW-1) and observation wells (OB-2, -3, -4) (b) Plan view of well locations at the top of high porosity injection layer at Nagaoka CO_2 injection site (from Mito et al., 2008).

Core samples and well logs from the observation wells provided data for a time lapse simulation study of the migration of CO_2 within the reservoir. Core samples from the drilled observation wells allowed the petrophysical properties of the reservoir and seal to be examined. Along with conventional core analysis, thin sections were made to examine pore geometries, mineralogy, and cementing materials (Xue et al., 2006). A baseline cross-well seismic tomography study was also completed prior to injection. This would allow for the future tracing of CO_2 migration between the observation wells (Kikuta et al., 2005). To allow for the future investigation of geochemical processes within the reservoir a number of formation water and rock samples were also taken prior to injection (Mito et al., 2008).

Injection

The primary components of the injection facility at the test site include a CO_2 vessel and evaporator, three pumps to control injection pressure and rate, and a heater to control the temperature of the CO_2 stream. A diagrammatic representation of the injection processing facility is shown in Figure 26.

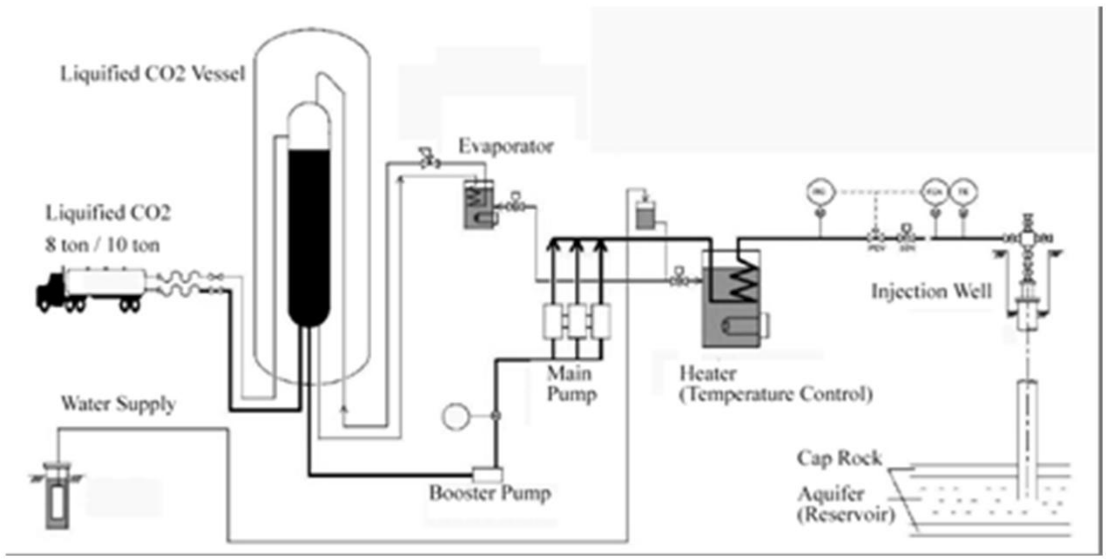

Figure 26. Diagramatic representation of injection facilities (from Kikuta et al., 2005).

The test site at Nagaoka is predominantly a research and development project and the injection rate is relatively low (20 t/day) (Michael et al., 2009) because the injected CO_2 must be purchased from an ammonia production plant (Nippon Tansan Co. Ltd). On 30th April 2004, after a fifty day break in injection due to a break in supply from the ammonia plant, injection recommenced at a rate of 40 t/day (Kikuta et al., 2005). At the point of injection the CO_2 stream is at 48^{0}C and greater than 19 MPa, and so is injected at the supercritical state (critical values 31^{0}C and 7.38 MPa) (Xue et al., 2006).

Monitoring

The Nagoaka test site focuses on the following 5 monitoring techniques:

- well logging;
- time lapse cross-well seismic tomography;
- induced microseismic monitoring;
- pressure and temperature monitoring;
- geochemical fluid and core sampling.

CO_2 was first detected in the reservoir at observation well CO_2-2, 40 m down-dip from the injection point. The presence of CO_2 at the well was detected by induction, sonic and neutron logs. It was found that sonic P-wave velocity decreased significantly with the breakthrough of the injected CO_2 in the injection wells. After changes in sonic velocity had been matched with predicted CO_2 saturation, a calculated sweep efficiency of 40% was suggested by Xue et al. (2006). Through continuous monitoring of pressure and temperature, an initial 6% increase in pore pressure was found at the observation well, although it is now thought that pressure build up associated with injection within the reservoir is subsiding (Xue et al., 2006; Kikuta et al., 2005).

Seismic tomography has also been successfully utilised at Nagoaka to monitor the migration of CO_2. After baseline surveys had been completed the first survey was completed with 3000 tonnes of CO_2 in the reservoir. In this survey P-wave seismic velocity appeared to be reduced by 9-10% due to the injection of CO_2 (Kikuta et al., 2005; Onishi et al., 2009). Recently a new seismic analysis technique known as 'difference analysis with data normalisation' (DADN) which analyses seismic response prior to inversion has been used to monitor the migration of the CO_2 plume at Nagaoka. This method has proved to effectively reduce unique coherent noise for particular receiver and source combinations (Onishi et al., 2009).

Outlook and Issues

The Nagaoka test site has been used as a successful demonstration of the injection and storage of CO_2 into an onshore saline aquifer. Seismic tomography has shown to this day that 10,400 t of CO_2 are being successfully stored within a high permeability zone in the aquifer and have not breached the caprock (Onishi et al., 2009). Also proven at the Nagaoka test site is the ability for effective solubility, ionic and mineral trapping of CO_2 alongside the more widely recognised structural trapping. It is thought that the more complex mineralogies of the reservoir rock at Nagaoka will enhance the effect of chemical reactions in the water-rock system and subsequently cause significant mineral trapping, and solubility trapping, which could solely store up to 29% of the injected CO_2 (Xue et al., 2009).

As injection has ceased at the test site, (July 05) further work will concentrate on the advancement of monitoring techniques on the previously injected $CO_{2.}$ Plans for future investigation include:

- developing a method for determination of dissolved CO_2 under in-situ conditions;
- interpreting an effect of CO_2 dissolution on a resistivity log;
- improving understanding of relationships between P-wave velocity, resistivity, and CO_2 saturation for quantification of the CO_2 monitoring.

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MRCSP Gaylord

Partnership: Midwest Regional Carbon Sequestration Partnership (MRCSP)
Project Type: capture & storage, onshore saline aquifer
Location: Gaylord, Michigan, USA
Partners: DTE Turtle Creek Gas Plant, Battelle Memorial Institute
Start date: 2008
Estimated Storage: 60,000 t
Project Website:
http://216.109.210.162/MichiganBasin.aspx

Injection Rate	25-600 t/day
Depth of Injection	1061 m
Reservoir Lithology	dolomite
Transport Method	pipeline
Porosity	12.5%
Permeability	22.4 mD
Formation and Age	Bass Islands Dolomite (Upper Silurian)
Thickness	21 m

Figure 27. Location and summary characteristics of the MRCSP Gaylord CO_2 injection site.

Overview

In this test carbon dioxide was injected into a deep saline formation that is located at an intermediate depth between gas-producing layers and oil-producing layers. The carbon dioxide comes from DTE Energy's Turtle Lake natural gas processing plant, near Gaylord, Michigan (Figure 27). After compression in the nearby compression facility, it is transported about 13 km via the existing carbon dioxide pipeline to the well. Injection occurs far below drinking water sources, which are at a depth of less than 300 m in this region.

Site Characterization

The sedimentary column at the test site including the Bass Islands Dolomite targeted for the injection is depicted in Figure 28.

Pre-injection

Preliminary modelling was based on regional data. In November 2006 a test well was drilled. Core samples taken included the Amherstburg Formation, a dense limestone that will provide a seal for the Bass Islands Formation, which is a porous brown dolomite. The data collected in the test drilling helped to create a site-specific model. In July 2007 an open house meeting was held to inform the community about the project. In January 2008 a permit was obtained and injection began on 21 February 2008, after a final well integrity test.

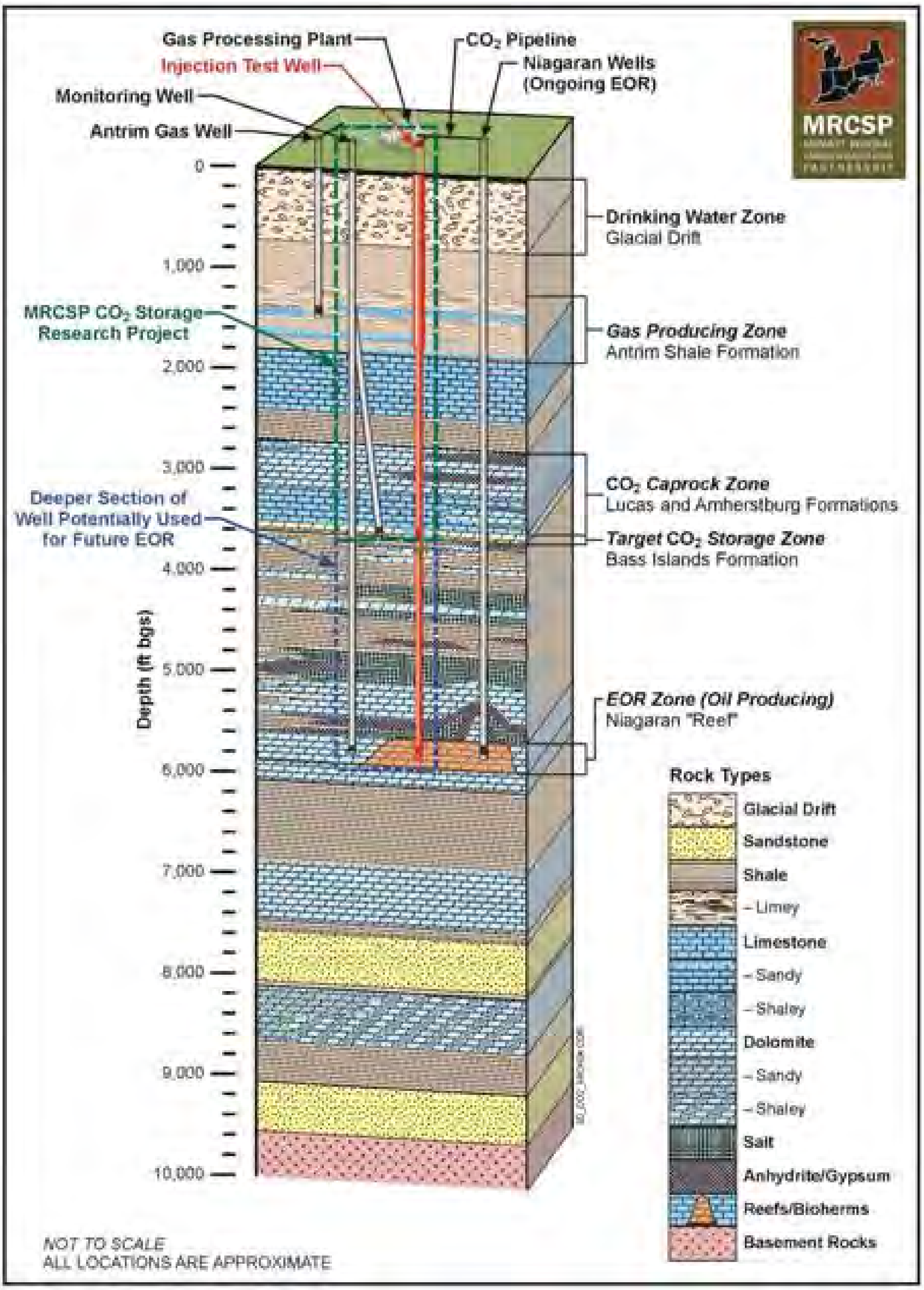

Figure 28. Sedimentary column at the MRCSP Gaylord injection site at the Michigan Basin (from http://216.109.210.162/MichiganBasin.aspx).

Injection

The initial test injected about 10,000 t into the target storage zone over a period of about three weeks in February and March 2008. At all stages the activities were monitored to track the condition of the well and the injected carbon dioxide. The behaviour of the carbon dioxide in the formation closely matched the behaviour predicted by the computer model prior to the field test.

The second test, which injected up to 50,000 t CO_2, took place in mid-February through to July 2009. Post-injection monitoring will follow together with evaluation and reporting the results to the public.

In February 2009 a second round of injection started and up until July 2009 50,000 t of CO_2 was injected. Monitoring was performed throughout the injection. The project has now moved to the post-injection monitoring phase.

Monitoring

In standard practice for the oil industry, well monitoring was used to keep tract of the injection rate, wellhead and formation pressure and temperature. To locate the injected carbon dioxide cross-well and 3-D seismic will be used while acoustic emissions will allow tracking the movement of injected CO_2. Wireline monitoring provides the porosity, saturation, and permeability data. Fluid sampling is conducted to track the carbon dioxide storage processes.

Outlook and Issues

10,240 tons of CO_2 were injected. Results of the test are consistent with the model.

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Ketzin

Partnership: EU Commission
Project Type: storage, onshore saline aquifer
Location: Ketzin, Germany
Partners: Consortium of 18 Partners
Start Date: April 2004
Estimated Storage: 60,000 t
Project Website: www.co2sink.org

Injection Rate	100 t/day
Depth of Injection	650 m
Reservoir Lithology	fluvial (silts and sands)
Transport Method	overland (road)
Porosity	5-35%
Permeability	750 mD
Formation and Age	Stuttgart Formation (Triassic)
Thickness	80 m

Figure 29. Location and summary characteristics of the Ketzin CO_2 injection site.

Overview

Commencing in April 2004, the CO_2SINK (CO_2 **S**torage by **I**njection into a **N**atural Saline Aquifer at **K**etzin) integrated project, is the first demonstration project of onshore CO_2 storage in Europe. The EU-funded CO_2SINK project, located near Ketzin, Germany (Figure 29), is run by a consortium of 18 partners, coordinated by the German Research Centre for Geosciences (GFZ). The project aims to focus on the migration of injected CO_2, utilising an array of geophysical, geochemical and microbiological monitoring techniques.

Site Characterisation

In 2005, a 3D 25-fold seismic survey providing 12 km² of subsurface coverage was acquired to allow an interpretation of the geological structure to be imaged at depths of up to 1000 m. The seismic survey confirmed initial interpretations, from original 2D surveys, that an anticlinal structure with east-west striking central graben, extends to the target horizon. Bounding faults were seen to have a throw of 30 m with no faulting imaged near the drill sites (Juhlin et al., 2007).

The target CO_2 reservoir, the Stuttgart Formation, is Triassic in age and fluvial in origin. The 80 m thick formation consists of sandstones and siltstones interbedded by mudstones, with sandstone channels of up to 20 m thick (Schilling et al., 2009).

Pre-injection

Three wells, one injection and two monitoring, were drilled at a distance of 50-100 m from each other, over a 6 month period in 2007. Wells were drilled to a depth of 750-800 m and were equipped as 'smart' wells with DTS (Distributed Temperature Sensors) and 45 electrodes (ERT array) of permanently installed down-hole sensors (Schilling et al., 2009). Prior to CO_2 injection a 6% KCl slug was injected to lower the risk of halite scaling due to desiccation of the highly saline brine (Schilling et al., 2009).

Injection

On 30th of June 2008, injection started at the injection facility, which consists of 5 plunger pumps (0-1000 kg/h), a heating device (305 kW) and two intermediate storage tanks (50 t each). CO_2 injection rates of 78 t/day can be facilitated at the site. Fibre optic temperature and pressure sensors are used to monitor conditions both within the well and in the reservoir. The project also focuses on assessing the optimum injection conditions whilst reducing the required electrical heating power.

Monitoring

Monitoring the migration of CO_2 is one of the primary aims of this project. A range of geophysical techniques such as 3D surface measurements, Vertical Seismic Profiling, Moving Source Profiling and crosshole seismic tomography are used to monitor both surface and subsurface anomalies. Electrical Resistivity measurements are also acquired via 15 electrodes in the casing of each well. The low resistivity of the CO_2 relative to the saline brine allows CO_2 saturation to be calculated and compared to out of situ laboratory studies. Gas composition is monitored via a Gas Membrane Sensor present in the two observation wells. Although the CO_2 at Ketzin is injected in a supercritical state, the temperature and pressure conditions in the reservoir will cause it to become gaseous without phase transition (Schilling et al., 2009). The temperature and pressure of the reservoir will be monitored by fibre optic Distributed Temperature Sensing and a fibre optic pressure sensor, respectively.

An array of geochemical investigations are also being utilised to monitor variations in fluid composition pre- and post-injection. Microbial analysis, such as FISH (Fluorescent In Situ Hybridisation) is being used to study processes linking, the injected CO_2, the rock substrate, the formation fluid and micro-organisms.

Outlook and Issues

After 531 t had been injected, CO_2 was discovered in the proximal observation well, 50 m from the injection point. CO_2 is yet to arrive in the second observation well (100 m from the injection point). This is in accordance with modelled simulations. With 60,000 t of CO_2 planned for injection, the pressure within the reservoir must be less than defined limits. Currently the rate of pressure increase is within the maximum values preset by the mining authorities (Schilling et al., 2009).

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Total Lacq

Project Type: storage, onshore depleted gas fields
Location: Lacq, France
Partner: Consortium of 6 partners
Start Date: 2006
Estimated Storage: 150,000 t

Injection Rate	75,000 t/year
Depth of Injection	4500 m
Reservoir lithology	carbonate
Transport Method	pipelines
Porosity	3%
Permeability	0.005-23.1 mD
Formation and Age	Meillon Dolomite (Jurassic)
Thickness	121 m

Figure 30. Location and summary characteristics of the Total Lacq CO_2 injection site.

Overview

In February 2007 Total announced the launching of the Lacq project expected to commence the end of the same year .The project is the first integrated CO_2 capture and storage system, using both oxyfuel combustion technology and injection. The site for this pilot study is Lacq Basin, south western France (Figure 30). The project was scheduled to run for two years using existing infrastructure. The pilot test was aimed at demonstrating the role CO_2 capture and sequestration can play at reducing green house gas emissions from industrial facilities. The scheme was developed also to enable Total to test oxycombustion technology (replacing air with pure oxygen producing less exhaust gas with higher CO_2 content) on an industrial scale at Lacq steam production site, as well as the transportation, injection and storage of CO_2 into a 4500 m deep depleted gas reservoir at Rousse field (30 km away from Lacq).

Site Characterisation

Total group has being operating this site (in Aquitaine Basin) for over 50 years. The facilities and the project are run by Total Exploration and Production France. The main sites for this project are the Lacq production plant and the Rousse depleted gas field which is to be used for capture and storage respectively.

The CO_2 is to be transported from the Lacq reservoir and stored in the Rousse gas field (which has only one well), into the reservoir at the depth of about 4500 m. Rousse field was chosen because the reservoir is adequately porous and directly overlain by approximately 2000 m of clay marl (flysh) and it has favourable structures in terms of long term stability (Figure 31). Also the field is not directly connected to any other aquifer. These are favourable characteristics, since CO_2 injected into the formation will most likely be absorbed and held back and remain chemically inactive. The field is also characterised by an interaction of a series of faults.

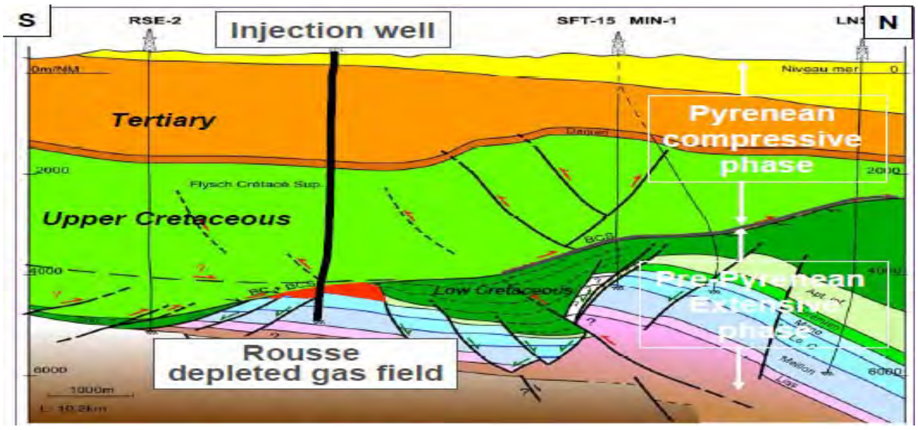

Figure 31. Stratigraphy and structural settings at the Rousse gas field (from de Marliave, 2009).

Pre-injection

The launch of the demonstration project was preceded by wide-ranging consultation of local stakeholders and a preliminary study in 2006. Oxycombustion was found to be the less expensive option and will aid in reducing the cost of capture (which is a large part of the total CCS cost).

These investigations also revealed that the Rousse field has a valid structural trap and the optimum condition for safe storage of CO_2. Engineering studies followed in 2007. One of the five boilers of the Lacq plant will be modified (for oxycombustion) to capture emitted CO_2 rather than release it into the atmosphere. The oxygen required will be supplied by a cryogenic unit that is capable of producing 240 t/day. The exhaust gas of high CO_2 content, will be cooled, piped to a compressor, dehydrated and fed to existing pipelines. For the first two years of the pilot project, the boiler is expected to capture about 200 t of CO_2 per day. The CO_2 will then be transported to Rousse gas field, travelling in the opposite direction of the natural gas that was previously produced at Rousse. Meanwhile a work-over will be needed at the injection site, which will involve installation of a temporary drill site, replacement of safety valves, improvement the appearance of the site etc., before the commencement of actual injection.

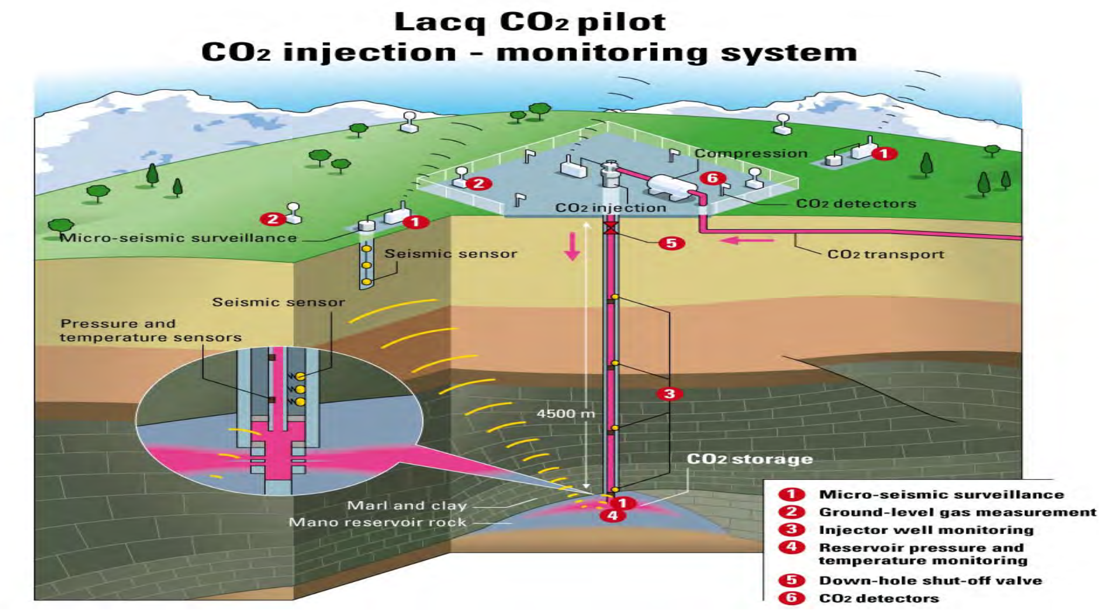

Figure 32. Schematic of the injection and monitoring phase (from Total website).

Injection

One of the boilers in the Lacq plant will be converted and used to produce small amounts of flue gas that is 90% CO_2. The carbon will subsequently be piped about 30 km from the Lacq plant to Rousse field nearby for storage. At the injection well the CO_2 is compressed and injected into depleted reservoir formation at the depth of 4500 m.

Special sensors will be placed in observation wells as well as in the injection wells to monitor the behaviour of the reservoir constantly during and after the injection of the CO_2. Additionally, other types of sensors and analysis units will be placed both at the surface and underground to detect and record anomaly that might occur during this test period.

Outlook and Issues

The construction work for the project was estimated to start in the 2nd quarter of 2008 and experimental operations expected to commence at the start of 2009 but the team experienced some set backs. It will commence in 2010.

Over the next two years, around 120,000 t of CO_2 will be captured and stored, an equivalent to the amount that would be emitted by 40,000 cars over the same period. The monitoring phase is to commence 3 years after the two-year injection period. The risk of leakage, which was a major cause for concern, reduced after careful studies of the proposed site in 2006 showing that it is a non-volcanic zone, where there are no natural exit channels for underground gas and given the fact the site of storage already had contained much more hydrocarbon in the past. Thus, the reservoir pressure at the end of injection is anticipated to be lower than it was when filled with hydrocarbon.

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PCOR Zama

Partnership: PCOR (The Plains CO_2 Reduction Partnership)
Project Type: Storage, Oilfield, EOR
Location: Zama City, Alberta, Canada
Partners: Apache Canada Ltd., Energy & Environmental Research Centre (EERC), Natural Resources Canada, Alberta Department of Energy, Alberta Energy and Utilities Board, Alberta Geological Survey.
Start Date: December 2006
Estimated Storage: between 30,000 and 60,000 t of acid gas
Project Website: http://www.undeerc.org/PCOR/default.aspx

Injection Rate	166 t/day
Depth of Injection	1470 m (average)
Reservoir Lithology	dolomite, limestone, pinnacle reef structure
Transport Method	unknown
Porosity	4-26%
Permeability	1-413 mD
Formation and Age	Keg River Formation (Devonian)
Thickness	15-343 m

Figure 33. Location and summary characteristics of the PCOR Zama CO_2 injection site.

Overview

The Zama Field demonstration is one of four CO_2 sequestration validation projects of the Validation Phase of the PCOR Partnership. This project will test the storage potential of acid gas that includes approximately 70% CO_2 and 30% hydrogen sulfide (H_2S). The acid gas stream will be obtained from the Zama natural gas-processing plant, owned and operated by Apache Canada Ltd. It will be injected almost 1.5 km below the surface into the Zama oil field, located about 16 km from the plant. The Zama geology includes steep, mound-like carbonate structures with an average size of 40 acres and 120 m in height. These structures are ideal traps for storing these gases.

Injection began in December 2006, and continued at a rate of 100 t/day over the next two years. This project has the ability to sequester 67,000 t of CO_2 annually. The Zama test will help determine the impact that high concentrations of hydrogen sulphide may have on carbon dioxide integrity, as well as enhanced oil recovery. Results will provide valuable data on the accuracy of how well carbon dioxide storage capacity can be predicted and also aid in validating geologic sequestration testing under acid gas conditions.

Site Characterisation

The site lies within the very extensive Alberta Basin. Stratigraphically, the injection zone is well contained between massive anhydrite and shale packages that will ultimately slow and or prevent the migration of any leaked injectate. The gas will be injected into the carbonate Keg River Formation which hosts a pinnacle reef structure. The geology of the pinnacle reef is well understood and offers an excellent opportunity to test and refine geologic CO_2 sequestration (Figure 34). Pinnacle reefs are self-contained underground hydrocarbon reservoirs. There is nearly 700 oilfield pinnacle reef “superdomes” in the Zama area that could be used to store CO_2-rich gas.

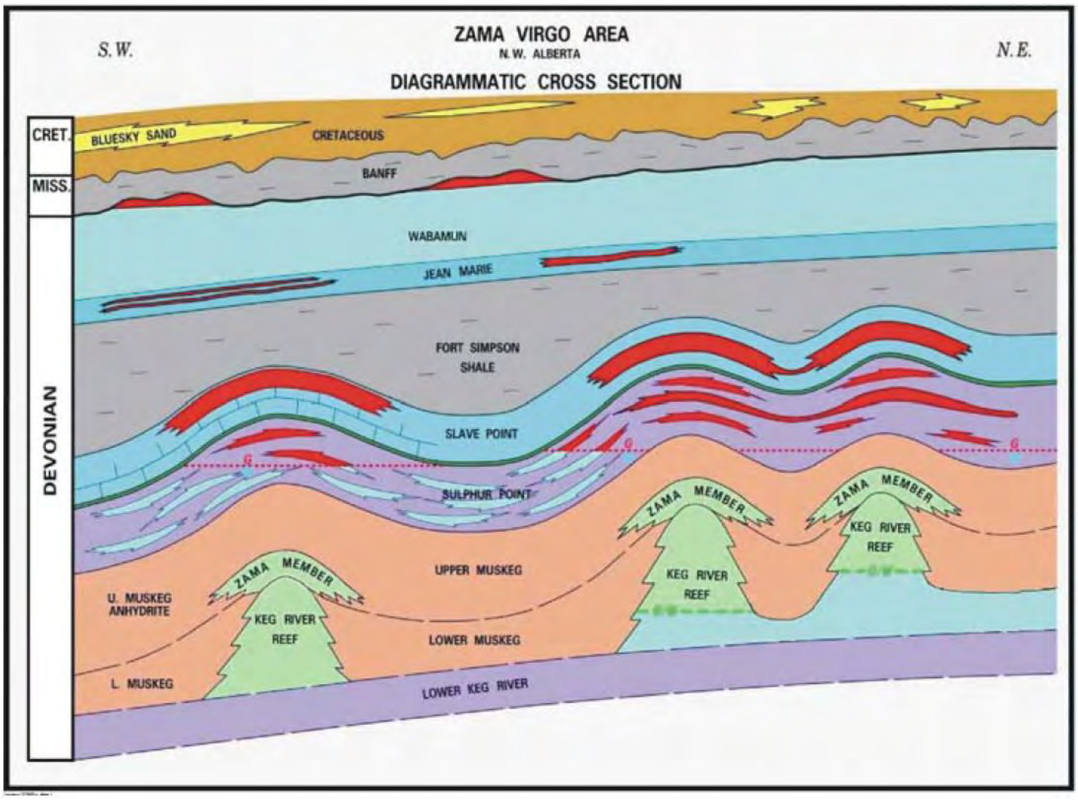

Figure 34. Schematic cross-section illustrating the sedimentary succession in northwestern Alberta (from Smith et al.)

Pre-injection

In June 2007 the evaluation of the Alberta Basin geological province, fluid flow regimes, and water quality for the area that encompasses the Zama subbasin was completed.

Injection pressure thresholds were established by geomechanical testing in the laboratory, log analysis, and numerical modelling. Laboratory tests have been conducted on core samples taken from the Zama Field, including compressive strength tests, static and dynamic elastic properties, pore volume compressibility, stress-dependent permeability, and compressional and shear wave velocities at varying stress levels.

Numerical and analytical geomechanical modelling has also been used to examine perturbations in the reservoir pressure, and hence the in situ regimes in the reservoir and cap rock, throughout the history of the field's initial oil production, water flooding and, most recently, acid gas injection.

The results from this integrated investigative program in the Zama Field indicated that both the dolomite reservoir and its overlying anhydrite cap rock are generally characterized by high mechanical strength, high stiffness, low compressibility, and very low permeability, thus have characteristics that favour the storage of acid gas.

Injection

The injection started on December 2006 at the rate of 250 t/day. The injection targets a pinnacle at the depth of 1600 m that has been depleted of hydrocarbons through primary and secondary production. The oil is extracted through another well. A third well, that has been plugged off, is being used for monitoring.

Between 30,000 and 60,000 t of acid gas is planned to be injected within the 4 years duration of the project, which is equivalent to sequestration of 42,000 t CO_2.

Monitoring

A number of techniques are being employed to monitor the effects of acid gas injection at the Zama site. The pre-injection state of each of these parameters has been determined with historical field data or field activities conducted in 2005 and 2006 to acquire new baseline data. The CO_2/H_2S plume will be monitored using reservoir pressure, wellhead and formation fluid sampling and the geochemical changes identified in observation or production wells. Monitoring of the injection well as well as the pressure within the reservoir and the overlying formations will provide data on the possible reservoir failure. Injection well condition, flow rates, and pressures will be monitored using the wellhead pressure gauges, well integrity tests, wellbore annulus pressure measurements and surface CO_2 measured near injector points and high-risk areas. Solubility and mineral trapping data will be provided by formation fluid sampling using wellhead or deep well concentrations of CO_2 and major ion chemistry and isotopes analysis. Leakage up faults or fractures will be checked with reservoir and aquifer pressure and with perfluorocarbon tracer monitoring.

Outlook and Issues

It is expected that after the injection the gas will travel and get trapped permanently in the pinnacles along the path. This process will occur on a geological scale and the gas is unlikely to ever reach the surface.

Ensuring the integrity of the caprock is a crucial element of the project. Preliminary research of the rock system in the Zama field indicates a favourable seal and reservoir conditions for acid gas sequestration. The failure of the caprock is not expected, however if it were to happen, the hydrogeological investigations predict that fluid flow process, dissolution and mineralizing reactions would slow down the movement of the plume and likely not allow it to get to the surface.

The findings of this project will allow assessing the storage capacity in other reef pinnacle structures within the Alberta Basin as well as in similar structures around the world.

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MGSC Decatur

Partnership: Midwest Geological Sequestration Consortium (MGSC)
Project Type: storage, onshore saline aquifer
Location: Decatur, Illinois, USA
Partners: MGSC, Illinois State Geological Survey, Archer Daniels Midland Company (ADM)
Start Date: 2008
Estimated Storage: 1 Mt
Project Website: http://sequestration.org/

Injection Rate	1,000 t/day, 330,000 t/year
Depth of Injection	1980 m
Reservoir Lithology	quartzose sandstone
Transport Method	unknown
Porosity	15%
Permeability	225 mD
Formation and Age	Mt. Simon Sandstone (Cambrian)
Thickness	300 m

Figure 35. Location and summary characteristics of the MGSC Decatur CO_2 injection site.

Overview

This project will test the ability of receiving 1 Mt of CO_2 over the period of 3 years by the Mt. Simon Sandstone. CO_2 will be supplied by the ethanol plant in Decatur, Illinois (Figure 35). A comprehensive Monitoring, Mitigation and Verification (MMV) program will be employed by MGSC throughout the project. The well will be drilled in spring 2008 and the injection is to begin in early 2010 and conclude in 2012.

Site Characterisation

Mt. Simon Sandstone constitutes a major saline reservoir in the American Midwest and it is the formation targeted in this project. Geology in this region contains numerous seals above the reservoir (Figure 36). Monitoring of the sandstones above the seal will give a warning of any leakage problems.

Pre-injection

In preparation for the injection some Monitoring, Mitigation and Verification (MMV) work in the field was done; installing monitoring wells (3 shallow and 1 deep well), installing vadose zone samplers, collecting background samples, as well as soil, brine and groundwater samples. Other activities included delivering CO_2 by tanks, installing the pipeline, and testing of the heater and the pump.

Injection

Beginning in early 2010, CO_2 will be injected in the site at the rate of 1,000 t/day. It is planned that by the year 2013 1 Mt will be sequestered.

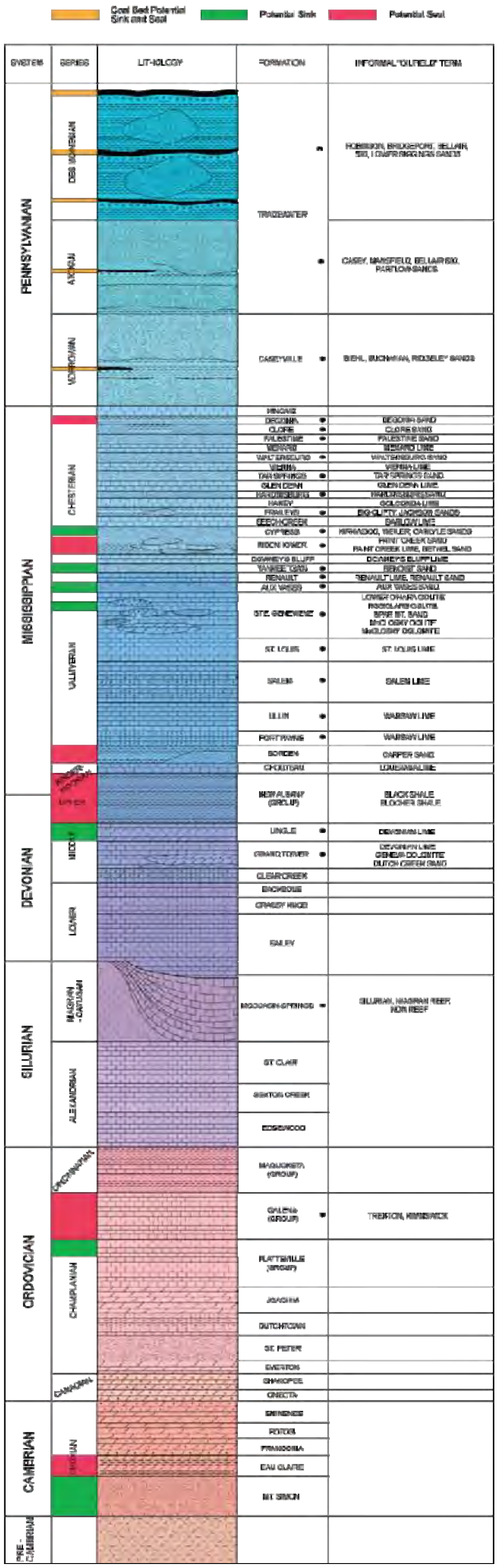

Figure 36. Sedimentary column at the MGSC Decatur site in Illinois Basin (from http://sequestration.org).

Monitoring (MMV)

The Monitoring, Mitigation and Verification (MMV) plan in this project includes atmospheric, vadose zone and groundwater monitoring. The ambient air quality is checked to ensure worker safety. Net surface CO_2 flux and soil CO_2 flux are checked. Remote sensing involves colour infrared orthoimagery and aerial photography to provide baseline map and to determine plant stress. Shallow geophysical monitoring involves Electromagnetic Induction and High Resolution Electrical Earth Resistivity to indicate areas that may have increased vapour content in shallow geologic material. Moreover, the wells are used to monitor shallow groundwater flow regime and water quality.

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SECARB Cranfield

Partnership: Southeast Regional Carbon Sequestration Partnership (SECARB)
Project Type: storage, onshore saline aquifer
Location: Cranfield, Mississippi, USA
Partners: SECARB, DOE/NETL & SSEB, Texas Bureau of Economic Geology, Denbury Resources Inc, Advanced Resources international, Electric Power Research Institute
Start Date: 2008
Estimated Storage: 1.5 Mt/year
Project Website: http://www.secarbon.org/

Injection Rate	4,109 t/day, 1.5 Mt/year
Depth of Injection	3140 m
Reservoir Lithology	sandstone, conglomerate
Transport Method	pipeline
Porosity	20%
Permeability	50-1000 mD
Formation and Age	L. Tuscaloosa Formation (Upper Cretaceous)
Thickness	~ 60 m

Figure 37. Location and summary characteristics of the SECARB Cranfield CO_2 injection site.

Overview

The plan for this project is to inject 1.4 Mt of CO_2 per year in 18 months. The source of CO_2 is a naturally occurring commercially available source (Jackson Dome) of high quality and low cost. CO_2 will be delivered by Denbury Resources' pipeline. This injection project targets the down-dip "water leg" of the Cranfield unit in Adams and Franklin Counties, Mississippi (Figure 37). The site lies about 25 km east of Natchez, Mississippi.

Site Characterisation

The Gulf of the Unites States is formed by a thick succession of sedimentary formations of Mesozoic to Cenozoic. The deposits include highly porous and permeable sandstones separated by regionally extensive and thick marine shales. Structurally, they abound in anticlines and fault-bounded traps which provide horizontal compartmentalization. The region has been under intense scrutiny in terms of oil and gas extraction, which has been well preserved in the structural traps. The Cretaceous Tuscaloosa Formation has been identified as the best storage target, with minimum storage capacity estimated at 14,000 million metric tonnes of CO_2. Data obtained in the injection test into this formation will be used to calibrate the estimation for the entire Gulf Coast, which at this time is estimated at 2,000 billion metric tonnes. The Cranfield test site was selected since it is a prime example of the structural trap and also because of its proximity to large volumes of CO_2 and the pipeline infrastructure. Initially the gas injected was obtained form a natural source (Jackson Dome), however there are plans to move to anthropogenic CO_2 provided the success of the initial stage of the operation.

Pre-injection

In the spring of 2008 a detailed characterization of the field was completed. Vintage wireline logs from 1940's were source of the structural data. Several hundred core plugs provided information about the fluid flow. 3-D seismic survey was performed.

The Tuscaloosa Formation at this site is composed of fluvial sandstones and conglomerates. The basal conglomerates overlie the marine shales.

Injection

High volume injection started on April 1, 2009 at a rate of 40,000 t CO_2 per month. The injection is being monitored via pressure and fluid sampling in far field wells. 250,830 t CO_2 were injected as of November 2009.

The anthropogenic test will begin in 2011, when between 100 and 150,000 t CO_2 per year will be available for the purposes of the project.

Monitoring

There is a comprehensive plan for post-injection monitoring of the CO_2 plume. Phase III of the project is panned for 10 years. The techniques that will be applied are: introduced noble gasses tracers, produced fluid composition, bottom-hole pressure. Distributed down hole temperature, pulsar neutron reservoir saturation, time-apse 3-D seismic imaging, Continuous Active Source Seismic Monitoring (CASSM), cross-well seismic tomography, passive seismic monitoring, above-zone pressure and fluid monitoring, cross-well electrical resistance tomography, subsurface deformation, CO_2 land surface-soil gas assessment, aquifer monitoring.

Outlook and Issues

The injection at Cranfield is going according to plan. The rate of injection is set to increase in the middle of 2011 to reach the target rate. The 11-month worth of data collected since the beginning of injection give a good indication that the injection will be accomplished successfully.

The anthropogenic test is in the phase of preparations. Gas from the Plant Barry is planned to be stored in the Citronele oilfield.

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K12-B

Partnership: Gaz de France Production Netherlands B.V and TNO
Project Type: storage, offshore gas field (nearly depleted)
Location: North Sea, Netherlands
Start Date: May 2004
Estimated Storage: 8 Mt
Project Website: http://www.k12-b.nl

Injection Rate	100-1,000 t/day, 475,000 t/year
Depth of Injection	3500-4000 m
Reservoir Lithology	sandstone/shale
Transport Method	unknown
Porosity	15%
Permeability	5-30 mD
Formation and Age	Slochteren Formation (Permian)
Thickness	350 m

Figure 38. Location and summary characteristics of the K-12B CO_2 injection site.

Overview

The K12-B project was the first in the world to inject CO_2 back into the same reservoir from which it was produced and described as Offshore Reinjection of CO_2 (ORC). This ORC project was aimed at examining the possibility of injection and storage in a nearly depleted reservoir. Also investigated were other issues such as enhanced oil recovery and well integrity. The field studied is located in the Dutch sector of the North Sea (Figure 38), specifically 150 km NW of Amsterdam and it was operated by Gaz de France Ltd. Although the field was discovered in 1981, production did not commence until 1987 (Vandeweijer et al., 2009). The gas produced contains a relatively high (13%) of CO_2 it has to be separated in other to meet the health and safety regulations. In 2004 the CO_2 was reinjected into the depleting Rotliegend reservoir from which it was produced using existing facilities. Prior to this project the CO_2 was vented into the atmosphere.

Site Characterisation

The target reservoir is the Upper Slochteren member of the Rotliegend Formation. As shown in Figure 39. This study revealed that due to a number of tectonic, sedimentary and diagenetic processes a high level of sedimentary heterogeneity is observed in the Slochteren Member.

The reservoir consists of interbedded eolian, fluvial and mud-flat facies with high (300-500 mD), medium (5-30 mD) and low permeability respectively (van der Meer et al., 2006). This is evident from the log section seen in Figure 40. The aeolian sandstones and some shales are extensive field-wide. However, most of the shales identified could be correlated only across short distances (few hundred meters).

The field is compartmentalised. It comprises a number of tilted fault blocks (with little or no pressure communication) as well as some sub-seismic reverse which may serve as horizontal barriers (van der Meer et al., 2006).

Pre-injection

In 2001, a preliminary assessment of the site was conducted, which gave rise to a school of thought that reinjection of CO_2 into the reservoir from which it originated (1160 m) might be relatively easy. This prompted the feasibility study carried out in 2002 aimed at creating a permanent injection site.

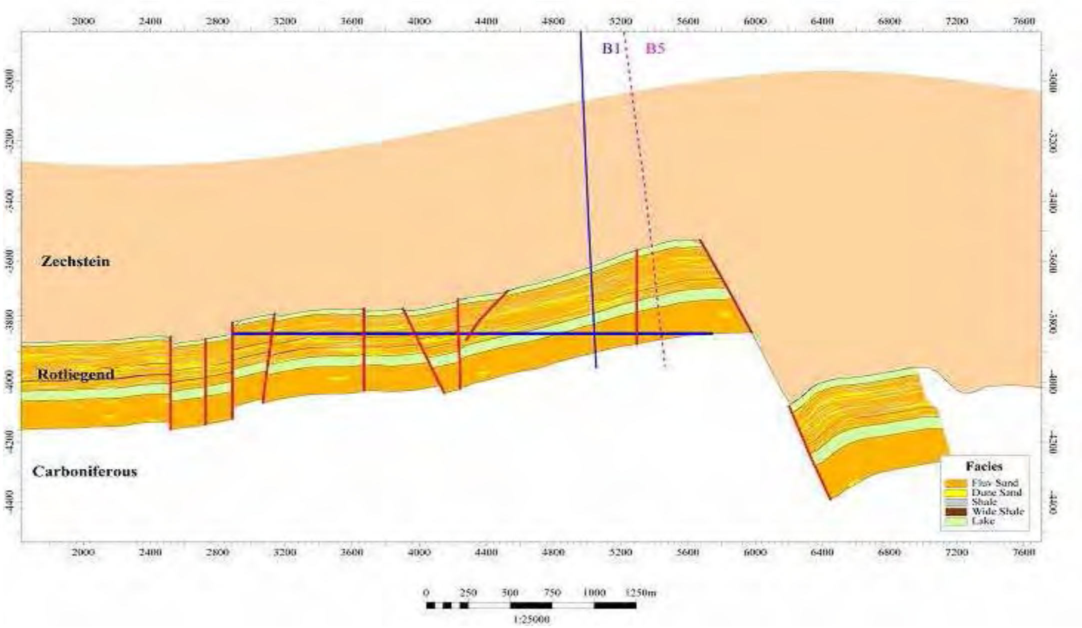

Figure 39. Cross section of the subsurface geology of the area (from van der Meer et al., 2006).

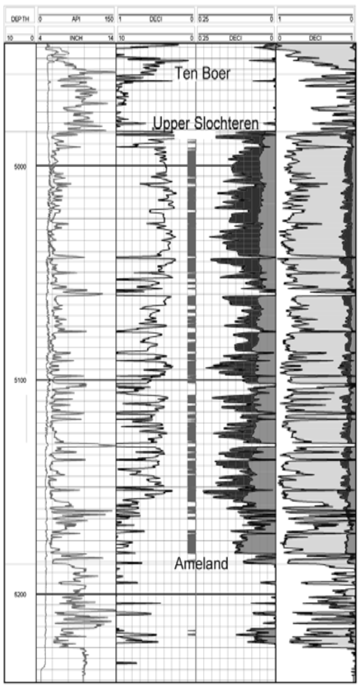

Figure 40. Composite log of well K12-B8 of the Upper Slochteren Sandstone showing the large number of shale layers intercalated in the sandstone.

Injection

Two injection tests where carried out for the K12-B ORC project. The first was in K12-B8 well and the second was performed in K12-B6. The later was located in compartment 3 and the former in compartment 4.

The injection of CO_2 commenced with the K12-8 well in May 2004. From this time to December of the same year there was stability with an average injection rate of 2350 kg per hour. The bottom-hole pressure increased by 9 bars as predicted by the reservoir simulation conducted earlier (van der Meer et al., 2006). Continuous monitoring was conducted between May – December 2005, with use of a down-hole memory gauge installed every three weeks, slightly above the top of the reservoir at 3657 m True Vertical Depth (TVD).

The next CO_2 injection test was between January and December 2005 on the K12-B well. Prior to the injection, monitoring of the high tubing head pressures had been performed since the end of production in 1999. The pressures were high due to the presence of compressed gas in the well bore, which resulted in a high water cut and consequently loss of the well (van der Meer et al., 2006).

Upon injection of CO_2 the gas pressure dropped dramatically, the water pushed back into the reservoir formation and the CO_2 injection pressure was normalised. It was monitored using gauges installed at 3610 meters TVD, and left for 6-8 days. An average injection rate of 26000 Nm^3/d of CO_2 was recorded throughout the test period (van der Meer et al., 2004). Several other parameters were also recorded:

- daily gas injection and production rates;
- pressures and temperatures at various locations;
- composition of the injected gas;
- presence of tracer elements in the produced gas.

Outlook and Issues

At the end of the Phase II (test injection), Phase III was expected to commence. The demonstration project was then upgraded to a full injection unit .The estimated total storage capacity for the field (i.e. all 4 compartments) is about 4,000 Mm^3.

At the end of Phase II it was concluded that CO_2 gas can be injected into depleted natural gas reservoirs at depth of about 3500 m. Injectivity is high despite the low average permeability of the reservoir rock. Moreover, there was an excellent fit between the injection pressure and the modelled value of 1.0-1.5 bars. The pressure differential between top and bottom of well was about 18 bars which is about 4 bars lower than was predicted. No hydrate problem was reported due to the pressure change.

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In Salah

Partnership: JIV (Joint Industry Venture)
Project Type: storage, onshore saline aquifer
Location: In Salah, Algeria
Partners: BP, Statoil and Sonatrach
Start Date: October 2004
Estimated Storage: 17 Mt
Project Website: www.insalahco2.com

Injection Rate	4,00 t/day, 1 Mt/year
Depth of Injection	1850 m
Reservoir Lithology	fluvial (silts and sands)
Transport Method	pipeline
Porosity	17%
Permeability	5 mD
Formation and Age	un-named strata (Carboniferous)
Thickness	29 m

Figure 41. Location and summary characteristics of the In Salah CO_2 injection site.

Overview

The In Salah Gas CO_2 project in Algeria (Figure 41) is a joint venture between BP (33%), Sonatrach (35%) and Statoil (32%) (Riddiford et al., 2004). Although the project is recognised as a CO_2 storage project, it coincides with the phased development of eight gas fields in the Ahnet-Timimoun Basin, Algeria. Production has initially been focussed on three fields: Krechba, Teguentour and the Reg field, where the natural gas contains 1-9% CO_2 (www.insalahco2.com). To comply with an export regulation of <0.3% CO_2 content, CO_2 removal facilities, along with compression and re-injection facilities have been installed at the site. CO_2 is currently being injected at a rate of 1.2 Mt/year into a Jurassic saline formation down dip from gas accumulations (Riddiford et al., 2004). Unlike CO_2 EOR, at In Salah it is hoped that CO_2 will not migrate into the hydrocarbon accumulations until cessation of production in 25-30 years time.

Site Characterisation

3D seismic acquisition was first completed in 1997/98 where the primary gas reservoir in the Krechba field was identified. From an amalgamation of seismic and well log data the primary reservoir is thought to be comprised of incised valley fill with the thickest and most extensive reservoir lying along the valley axis. The reservoir is a low relief anticline 20 m thick and at the injection site, at 1880 m depth, and has an average porosity of 15% and permeability of 10 mD (Ringrose et al., 2009). The reservoir unit has a virgin temperature and pressure of 93ºC and 175 bars, respectively, with the occasional appearance of fractures and small faults (Iding and Ringrose, 2009).

Pre-injection

In 2002 three horizontal injectors were drilled into the Carboniferous reservoir (Figure 42) (Ringrose et al., 2009). To maximise the injection capacity, injection wells were drilled perpendicular to the stress field, and therefore the dominant fracture orientation (Ringrose et al., 2009). Wells were also steered using an integration of real-time porosity data from the drill bit, combined with subsurface porosity models derived from 3D seismic, to optimise the quality of reservoir penetrated (Riddiford et al., 2004).

Injection

1.4 million standard cubic meters of CO_2 are removed everyday from the processing plant at Krechba. To inject into the relatively low permeabilities of the Carboniferous sandstone, CO_2 must be compressed to extremely high pressures of 185 bar. Pressurisation takes place in two high volume compressor trains where CO_2 is compressed by electric motors in four stages. The electric motors require 24 MW of power, which is around two thirds of the sites total power generation output (www.insalahco2.com). Due to the high amount of energy needed to compress the $CO_{2,}$ it has a discharge temperature of 250ºC. This temperature is regulated at each stage of compression, along with the dehydration of $CO_{2,}$ at stage three using a glycol dehydration method. This deters wet CO_2 from reacting with ferrous metals in the carbon steel of the 14 km-long pipeline, from processing plant to injection site (www.insalahco2.com). With CO_2 being injected at the three injection sites at 185 bar it is in the supercritical phase. Injection rate is limited to ensure that a pressure increase of no greater then 10 MPa above the ambient pressure to ensure that the fracture pressure is not exceeded (Rudqvist et al., 2009).

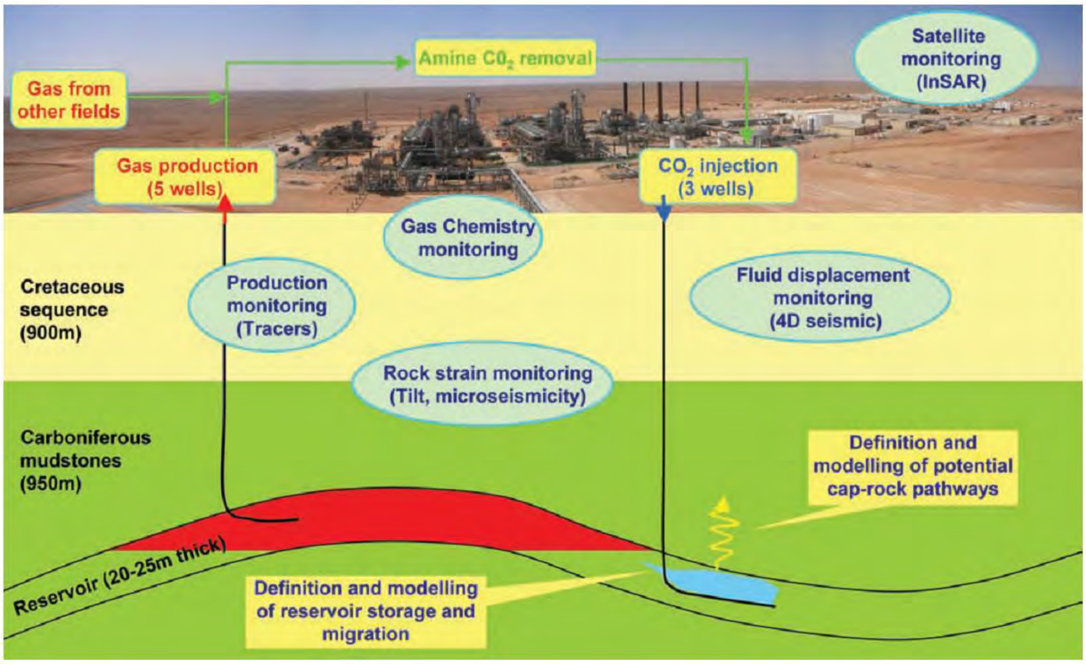

Figure 42. Summary of the In Salah CO_2 injection and storage site at Krechba with the main monitoring activities (from Ringrose et al., 2009).

Monitoring

At In Salah a total of 18 wells intersect the Carboniferous reservoir and aquifer. This has not only allowed for a detailed reservoir characterisation, but also for the subsequent monitoring of CO_2 within the reservoir. Geochemical monitoring is underway at In Salah, where surface and soil gas monitoring and down-hole gas measurements (head gas and isotube samples) have been added to CO_2 from each injection well, to allow it to be differentiated from natural CO_2 in the aquifer, and to be traced back to each injection well (Ringrose et al., 2009). Geophysical monitoring of the CO_2 plume at In Salah has been relatively limited, with the installation of a down-hole geophone detector in a dedicated well, planned for the near future.

This will give a better understanding to both the saturation and pressure changes within the CO_2 reservoir (Ringrose et al., 2009).

Another monitoring technique used at In Salah to trace the migration of CO_2 is satellite imagery. Although not a common monitoring technique, satellite imaging at the Krechba site, has indicated an 8-10 mm positive deformation between the three injections wells (Mathieson et al., 2009). Although this does not currently pose any environmental threat, it will allow an evaluation of both the geomechanical response to injection and to the migration pathway of CO_2. Along with monitoring the magnitude of uplift, the orientation of plume migration has also been found to be consistent with the predominant fracture orientation in the reservoir, in a NW-SE orientation (Mathieson et al., 2009). Deformation is thought to occur due to a poro-elastic response to increased injection pressure in the reservoir.

Outlook and Issues

To date at In Salah around 2.5 Mt of CO_2 has been injected into the Carboniferous reservoir at Krechba. With a plan to inject CO_2 over the next 25 years, future work will be concentrated on monitoring the fate of that injected CO_2. A key step to the progression of monitoring at In Salah will be the instalment of the following techniques/processes:

- acquisition of time-lapse 3D seismic;
- micro seismic, to assess the extent of stress on the reservoir and the overburden;
- deployment of GPS and tilt meters to calibrate satellite imagery;
- drilling of a dedicated geo-phone detector well;
- drilling of shallow wells to assess geochemical anomalies in the vadose zone.

Although 2.5 Mt of CO_2 have been successfully injected, a key number of issues have been discovered. It has been noted that CO_2 plume development is incredibly heterogeneous at this site and requires development of fracture flow modelling along with geo-mechanical modelling (Ringrose et al., 2009). Another issue of significant importance was a suspected leak at one of the injection wells. The leak, which was on an order of magnitude of a few cubic feet per day, caused the injection well to be shutdown for a period in June 2007. This was seen however to be a temporary issue, that has been rectified by changing a flange on the well head (Ringrose et al., 2009).

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Weyburn

Partnership: government, industry and research institutions
Project Type: storage, EOR
Location: Weyburn, Saskatchewan, Canada
Partners: about 15
Start Date: 2000
Estimated Storage: 20 Mt
Project Website:
http://www.ptrc.ca/weyburn_overview.php

Injection Rate	3-5,000 t/day, 2.7 Mt/year
Depth of Injection	1418 m
Reservoir Lithology	limestone/dolomite
Transport Method	pipeline
Porosity	8-38%
Permeability	1-300 mD
Formation and Age	Charles Formation (Mississippian)
Thickness	30 m

Figure 43. Location and summary characteristics of the Weyburn CO_2 injection site.

Overview

This is a commercial-scale project. Weyburn Oilfield is located southeast of the city of Regina in Saskatchewan, Canada (Figure 43). The field was discovered in 1954 with estimated 1.4 billion barrels of oil in place. Production commenced in 1955 and increased further in 1966, after water injection. In the next 20 years production declined steadily. This created a need for an alternative solution to enhanced oil recovery and probably storage of CO_2. Weyburn CO_2 project is funded by several energy companies, US and Canadian governments and the European Union. The aim was both to effectively produce a more sufficient amount of oil in place, thus extending the commercial life of the field, and to find the possibility of the injected CO_2 becoming permanently stored 1400 metres deep in the subsurface over the life time of the project.

There are two projects at Weyburn. There is a commercial CO_2 Enhanced Oil Recovery (EOR) project run by EnCana, a major oil company. The second research project known as the International Energy Agency Greenhouse Gas Weyburn-Midale CO_2 Monitoring and Storage managed by the Petroleum Technology Research Centre, which was split into two phases. Phase I involved geological characterization, prediction and monitoring of CO_2 movement, estimating capacity and risk assessment of the storage site and it was performed in 2000-2004. Phase II began in 2005 and is expected to finish in 2011. It should tackle issues like monitoring and verification, wellbore integrity as well as performance assessment. The amount of original oil in place (OOIP) was 1.4 billion barrels, and the projected amount of enhanced oil recovery (using CO_2) is estimated at 155 million barrels. The projected amount of CO_2 storage is estimated at over 30 Mt gross, and over 26 Mt net.

Site Characteristics

The Weyburn Oilfield lies in the Williston Basin and covers approximately 80,000 km^2. It has a relatively simple structural features and a complete sedimentary rock record (Heck et al., 2000).

Most of the hydrocarbon in this area is produced from the Palaeozoic rocks, specifically, from the Midale Beds of Mississippian Madison group (Figure 44). The Midale Beds are overlain and underlain by the Midale Evaporite and the Frobisher Evaporite, respectively. The reservoir can be further subdivided into two units (Figure 45) as follows:

- Midale Vuggy bed is a densely fractured heterolithic and stylolitic limestone with porosity between 8-20% and permeability about 10-300 mD. The water injection in 1964, which helped the field achieve its peak production, efficiently swept the oil from this unit.
- Midale Marly Bed has a much high porosity (16-38%) and lower permeability (1-50 mD).

This interval requires the use of CO_2 as an effective solvent to extract the oil from the pores because of the low permeability values. Moreover, although fractures and faults (most likely induced by the Palaeozoic salt dissolution) were identified in the mapped area, they have not compromised the reservoir integrity.

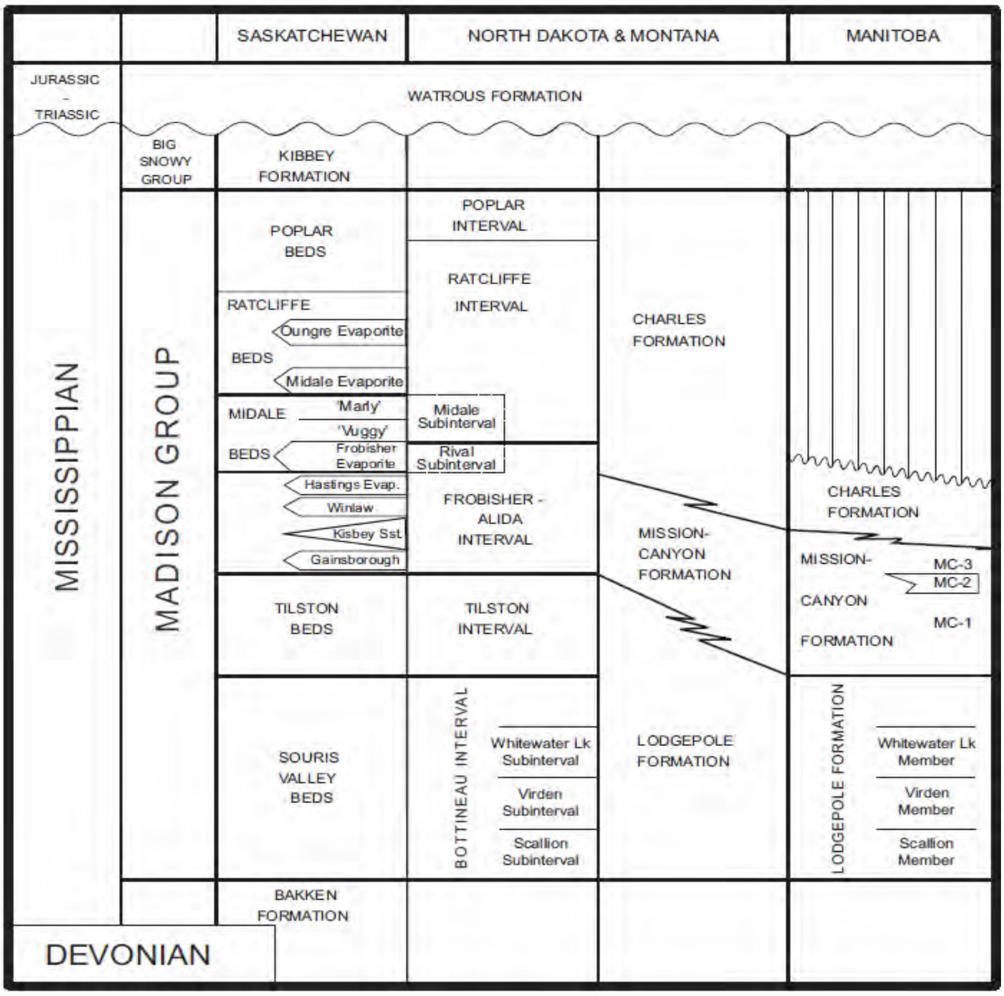

Figure 44. Stratigraphic correlation of the Mississippian in Saskatchewan, North Dakota, Montana and Manitoba (from Wegelin, 1984).

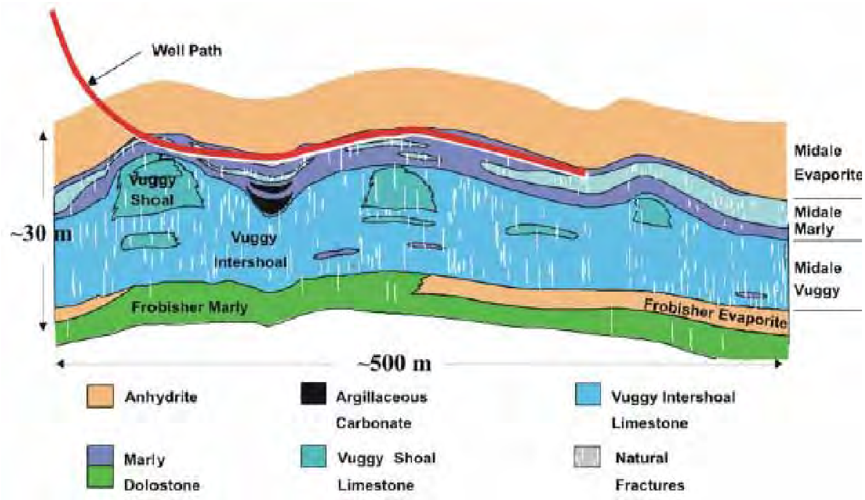

Figure 45. Schematic of the reservoir geology, Midale Beds, Saskatchewan, Canada**.**

Pre-injection

A number of new techniques, reservoir mapping and predictive tools were used to understand and characterise the processes involved in the behaviour and movement. Also investigated was the CO_2 capacity within the formation in the subsurface.

Injection

The CO_2 used is a purchased by-product of coal gasification and supplied to Weyburn through a 320 km long pipeline from the Great Plains Synfuels Plant in Beulah, North Dakota, USA. Phase IA of CO_2 injection started in September 2000 with an initial injection rate of was 5000 t/day. Injection was originally in 18 patterns of nine wells, each at the west end of the oilfield. In order to achieve the goal of flooding 75 patterns, an extension of the CO_2 flood to the south-east within the next 15 years is necessary.

Monitoring

This stage of the project involves building a comprehensive understanding of CO_2 storage by monitoring CO_2 being used for EOR at EnCana's Weyburn Field and Apache's Midale Field. Background information is collected prior to the CO_2 flood. This allows comparison of field characteristics before and after CO_2 injection and enhances understanding of the relationship between oil recovery and CO_2 storage.

Both geochemical and seismic imaging methods have being applied to monitor the Weyburn CO_2-EOR of the Phase I area. Prior to injection, baseline surveys were conducted as a basis for subsequent analysis.

At the end of Phase I, geochemical studies of soil samples taken before and after injection revealed that there is no evidence of CO_2 escape. The CO_2 front was identified, since the time-lapse seismic surveys showed high sensitivity to the low levels of CO_2 component and vice versa. The fracture network in the reservoir contributed to the spread of CO_2.

Outlook and Issues

The primary benefit of the project was the objective evaluation and large-scale demonstration, of the geological sequestration of CO_2 during EOR operations. Assessment was conducted to understand the long-term fate and effect of CO_2 injected into subsurface. Areas for future research include the relationship between caprock topography and CO_2 leakage.

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Snohvit

Partnership: Statoil and partners
Project Type: storage, offshore saline aquifer
Location: Barents Sea, Norway
Partners: Statoil (22.9%), Petoro (Norwegian state direct interest), TotalFinaElf (18.4%), Gaz de France (12%), Norsk Hydro (10%), Amerada Hess Norge (3.26%), RWE-DEA Norge (2.81%), Svenska Petroleum Exploration (1.24%)
Overall Cost: 5.2 billion USD
Time Scale: Start date: Oct 07, Injection: Apr 08, Life-span: 30 years
Estimated Storage: 23 Mt
Project Website:
http://www.statoil.com/en/TechnologyInnovation/ProtectingTheEnvironment/CarboncaptureAndStorage/Pages/CaptureAndStorageSnohvit.aspx

Injection Rate	2,000 t/day, 750,000 t/year
Depth of Injection	2700 m
Reservoir Lithology	sandstone
Transport Method	offshore platform-platform pipeline
Porosity	10-15%
Permeability	185-883 mD
Formation and Age	Tubean Formation (Mid Jurassic)
Thickness	45-75 m

Figure 46. Location and summary characteristics of the Snohvit CO_2 injection site.

Overview

The Snohvit LNG (Liquified Natural Gas) project, on-stream since October 2007, is operated by Statoil and a number of partners. The Snohvit Unit Area is located in the Barents Sea, around 145 km from land (Figure 46). Three gas fields (Snohvit, Albatross and Askeladd) discovered in a period 1981-84 have an initial gas in-place of 317,000 Mm^3 (Estublier et al., 2009). As CO_2 will solidify under the process of liquefying natural gas, it must be removed from the raw gas stream prior to processing. Rather than vent the removed CO_2 into the atmosphere, it is being injected into a saline aquifer, deeper than the producing gas fields, at around 2700 m depth. Along with a proposed 21 gas producing wells, a single dedicated CO_2 injection well is injecting at a rate of 700,000 t/year. In the predicted 30 year life span of the plant 23 Mt of CO_2 are to be stored.

Site Characterisation

The targeted CO_2 injection reservoir is the 45-75 m thick, Mid Jurassic Tubean Formation. It has been penetrated by 15 of 17 exploration wells which have informed characterisation of the storage site. The formation is sand dominated with some laterally restricted intra-reservoir shales and coals (Net sandstone To Gross thickness – NTG: 0.8-0.9) and has an average porosity of 10-15% (Madal and Tappel, 2004). The distribution of intra-reservoir units is not consistent within or between wells and so reservoir connectivity is difficult to quantify. However, due to the discontinuity of intra reservoir shales, it was predicted that the Tubean Formation reservoir will provide adequate vertical and lateral communication. The seal to the reservoir is provided by the lower unit of the 60-105 m thick Nordmela Formation. The lower unit (Nordmela 2) is a low permeability (1-23 mD), extensive band of 25-30 m thick shale, that naturally seals fluids in the Tubean Formation that have a CO_2 content of 5 mol% (Estublier et al., 2009). For these reasons it is thought that is will provide a sufficient long-term barrier to the migration of CO_2. Both a structural and stratigraphic representation of the reservoir and seal are portrayed in Figure 47 (www.statoil.com).

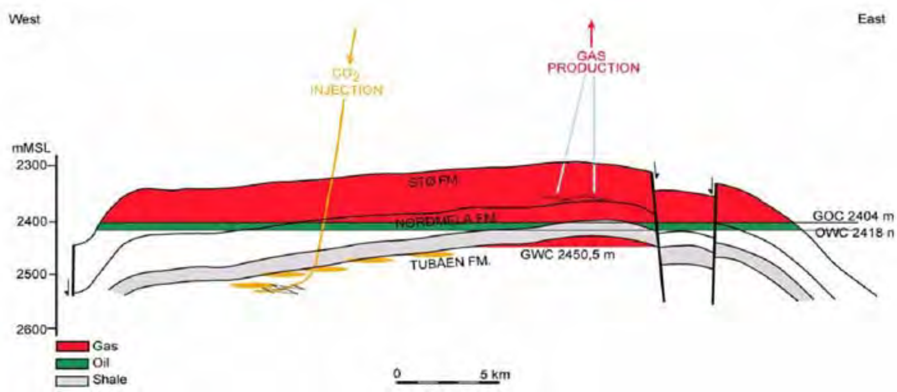

Figure 47. Stratigraphy and structure of the Snohvit CO_2 injection site (from Torp). Depth in metres below mean sea level (mMSL). GOC – Gas-Oil Contact. OWC – Oil-Water Contact.

Pre-injection

Prior to injection extensive reservoir simulations were completed, focussed on the varying sealing capacities of the two reservoir penetrating faults (Figure 47). If the faults are presumed to be sealing, the CO_2 will remain within the reservoir causing a significant pressure build up. This may limit injection rates to 4 Mt per year for six years to stay within the rock fracture pressure of 390 bar, and subsequently has defined the maximum storage capacity of the reservoir to 23 Mt (Elsubier et al., 2009). If simulation parameters are modified to represent non-bounding faults, it is predicted that only 5% of injected CO_2 will remain within the reservoir over a period of 1030 years. The boundaries of the modelling work completed by Elsubier et al. (2009) will have to be increased to comprehensively predict the migration of CO_2 over a period of 1020 years and more.

Injection

The injection facilities at the Snohvit site are located on the island of Melkoya, up to 170 km away from the injection site. In order to prevent the formation of hydrates and corrosion of the pipeline the water content of the CO_2 must be significantly reduced. The dehydration is conducted in two stages where the water content is reduced to a 1,000 parts per million (ppm) and subsequently 50 ppm with the use of a molecular sieve. The CO_2 stream is also compressed to between 80 and 150 bars at around 16°C, in the supercritical state. In the well-head the CO_2 stream is at around 4°C, before it encounters reservoir conditions of 98°C and 285 bar. (Elsubier et al., 2009). The slightly deviated injection well is 17.8 cm in diameter and is installed with pressure sensors both down-hole and at the wellhead.

Monitoring

Given the remote and challenging location of the injection site, the injection process is controlled and monitored via an umbilical line from the processing site at Melkoya, 145 km away. Pressure sensors both down-hole and within the wellhead allow reservoir pressure to be monitored. Pressure sensors also allow the effect of temperature changes and breaks in injection on the density of the hydrostatic CO_2 column to be monitored. The Snohvit project monitoring facilities are groundbreaking, because of their remote aspect (www.co2captureandstorage.info). However, the range of monitoring techniques used at Snohvit are limited when compared to Statoil's other two saline injection programmes at In Salah and Sleipner (Table 4).

Table 4. Monitoring methods at In Salah, Sleipner and Snohvit (after Wildenbourg et al., 2009).

Monitoring Methods			In Salah	Sleipner	Snohvit
Subsurface	**Seismic data**	4D surface seismic	Y	Y	Y
		high resolution – 2D seismic	-	Y	-
		well seismic VSP	Y	-	-
		micro-seismicity	Y	-	-
	Non seismic and borehole data	EM/electrical	-	Y	-
		gravity	Y	Y	-
		tiltmeters	-	-	-
		well fluids	Y	-	-
Surface and near surface		seabottom imaging	-	Y	-
		soil gas	Y	-	-
		surface flux	Y	-	-
		ecosystems	Y	Y	-
		satellite remote sensing	Y	-	-

Outlook and Issues

Injection into the Tubean formation commenced on the 22 April 2008. Future concerns will therefore be focussed on the fate of injected CO_2 and the monitoring of pressure build up within the reservoir. Although the monitoring of CO_2 using 4D seismic has been successful at the Sleipner site, with CO_2 having a large effect on the seismic response, there are concerns that the different characteristics of injection at the Snohvit site may cause monitoring difficulties (Madal and Tappe., 2004). The differences in characteristics are noted in Table 5.

Table 5. Comparison of the CO_2 injection sites at Sleipner and Snohvit, Norway.

	Utsira Formation (Sleipner)	Tubean Formation (Snohvit)
Porosity	35-40%	10-15%
Injection depth	800-100 m	2400-2600 m
Gas cap	No gas cap above CO_2 reservoir	Minor gas cap above CO_2 reservoir

Elsubier et al. (2009) have portrayed in their long term simulations of CO_2 migration that the sealing properties of the reservoir penetrating faults will have a prominent control on the fate of CO_2 .

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Sleipner

Partnership: EU Commission
Project Type: storage, offshore saline aquifer
Location: Norwegian North Sea
Partners: Consortium of 18 Partners
Start Date: October 1996
Estimated Storage: 25Mt
Project Website: www.statoil.com/en/technologyinnovation/newenergy/co2management/pages/sleipnervest.aspx

Injection Rate	2,800 t/day, 1 Mt/year
Depth of Injection	1012 m
Reservoir Lithology	unconsolidated sandstone
Transport Method	offshore platform-platform pipeline
Porosity	35-40%
Permeability	1-8 D
Formation and Age	Utsira Sand (Miocene)
Thickness	250 m

Figure 48. Location and summary characteristics of the Sleipner CO_2 injection site.

Overview

Commencing in October 1996 the Sleipner project, run by Statoil, began injecting CO_2 into a saline aquifer in what was to be the first demonstration project of carbon storage in the world. Although seen to be a demonstration, the Sleipner project has been injecting CO_2 on a fully commercial basis. The natural gas produced at Sleipner contains around 9% CO_2 (www.statoil.com) and therefore the CO_2 percentage must be lowered (2.5%) before it is pumped south via the Zeebrugge export pipeline. In 1990 however, the Norwegian government introduced a tax on CO_2 which today equates to around 50 USD/t (www.statoil.com). For this reason it made economic sense for Statoil to capture the CO_2 using a conventional amine process, and then transport it to a deep saline aquifer for permanent geological storage.

Site Characterisation

The site at Sleipner West (Figure 48) is composed of a well head platform, Sleipner B (SLB), and a treatment platform, Sleipner T (SLT). The platforms lie around 12.5 km from each other and are linked via a flow line. The well head platform is externally controlled from the gas producing, Sleipner A (SLA) platform, via an umbilical line. The target for geological storage is a small structural closure that was initially identified in 1994, by 3D seismic (Arts et al., 2008). The structural closure lies within the shoreface deposits of the Utsira formation. The Utsira formation is Miocene and up to 300 m thick in places (Hermanrud et al., 2009). It consists of loosely consolidated sandstones deposited in a lower shoreface setting. Sands, thought to be deposited in marine mass flows at water depths of around 100 m are split by thin intra-reservoir mudstone layers. The formation’s porosity of 35-40% and permeability of 1-8 D give it excellent reservoir characteristics. The formation is around 250 m thick at the injection site which lies at a depth of 1012 m; 200 m below the top of the gas field reservoir (Arts et al., 2008).

The caprock to the reservoir is provided by a 250-330 m thick shale package known as the Nordland Formation, which is Pliocene in age. Core testing suggests that the cap-rock is capable of sealing a CO_2 column of at least 100 m but perhaps up to 400 m depending on the density of CO_2 (Arts et al., 2008).

Pre-injection

Prior to injection, the targeted storage site was mapped by 3D seismic surveys, along with well logs and core samples from the reservoir sand. Although water sampling was tried, the unconsolidated form of the Utsira Sand meant that only drilling fluids and sand could be retrieved (Torp and Brown, 2002). A reservoir simulation was also performed prior to injection. It was predicted that CO_2 at 100 m depth would be in a supercritical phase. Due to its buoyancy it was predicted that the CO_2 would migrate to the top of the Utsira Sand, before being trapped by the caprock and migrating laterally. Due to the high permeability and high pore rock volume of the reservoir, it was estimated that there would be no significant pressure build up during the 25 year production life (Torp and Brown, 2002).

A further concern involved the slightly corrosive properties of $CO_{2.}$ To prevent any risk of CO_2 reaching the production wells below the Sleipner platform, a deviated horizontal well was drilled that would inject 4 km away from the gas field.

Injection

An injection rate of 1 Mt per year has been achieved at Sleipner since 1996 (www.co2captureandstorage.info). Before injection occurs the CO_2 is compressed in stages to 80 bars and cooled to 40°C, where it is then in the supercritical state. To achieve the stated injection rate, four parallel units, a fluid knock out drum, a compressor, a cooler and a gas turbine driver were installed (Torp and Brown, 2002).

Water is removed at 30°C for every stage of compression. The resultant injectate has no free water at the wellhead, which both limits corrosion and hydrate formation. The injection well is composed of chromium duplex steel, again to limit corrosion, and has a total length of 3752 m. The main deviation from the otherwise standard injection well is the high angle of inclination (83°) needed for the well to terminate in the lower Utsira Formation (Torp and Brown, 2002).

Monitoring

The fate of injected CO_2 in the 'Utsira Sand' has been carefully monitored by a consortium of partners previously working under the project name of SACS – Saline Aquifer CO_2 storage programme, but which today is known as CO2STORE. The monitoring of the CO_2 plume has been predominantly achieved using 3D seismic data. As explained by Arts et al. (2008), baseline 3D seismic data has been acquired and published six times since 1996. Predicted changes in seismic velocity were estimated from acoustic rock properties taken from well logs and out of situ laboratory work. The effect of CO_2 on the seismic can be easily viewed (Figure 49), with the CO_2 plume being modelled by a large multi-tier feature, comprising nine discrete sub-horizontal reflections (Arts et al., 2008). These bright reflections are thought to represent increased CO_2 saturation which is thought to be derived from accumulations, up to a few m thick, of CO_2 under intra-reservoir mudstones. This can be seen in 2D seismic cross sections in Figure 49.

Seismic acquisition also took place in 2008. However, the data has not yet been published by Statoil or CO2STORE.

Along with 3D seismic surveys, time-lapse seafloor gravity surveys have also been utilised at Sleipner to trace the CO_2 plume. Gravity surveys were conducted in 2002 and 2005 with 5.19 Mt and 7.76 Mt in the plume respectively. Thirty benchmark survey stations were deployed in two perpendicular lines, overlapping the subsurface footprint of the CO_2 plume. Although a gravity anomaly of up to -13.7µGal could be traced; the measurements are dependant on CO_2 density, temperature conditions and the effect of dissolution (Arts et al., 2008). It is thought that future gravimetry studies will portray a larger gravity anomaly with a greater confidence in the variable parameters.

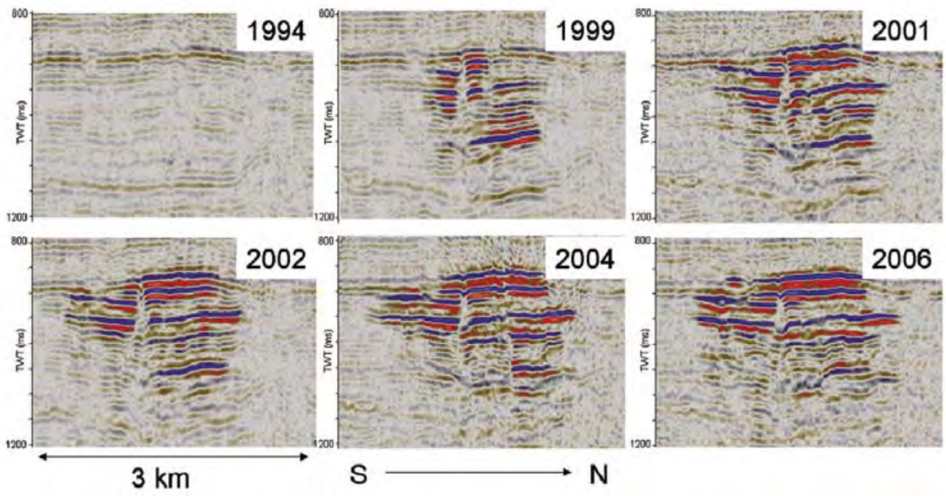

Figure 49. 2D seismic cross sections of the Sleipner site (from Arts et al., 2008).

Outlook and Issues

As mentioned previously, it is thought that pressure build up in the reservoir will not be an issue at Sleipner (Torp and Brown, 2002). With a planned injection total of 25 Mt, the main concern for the continued injection at Sleipner is the fate of injected CO_2. It is thought that currently, around one-third of injected CO_2 is stored in structural closure, above the structural spill points of the top two intra-reservoir mud (seen in the top two sub horizontal high amplitude reflections in the seismic in Figure 49). The remaining two-thirds lie below these spill points with one-third permanently remaining below the lowest two intra-reservoir traps. The extent of migration of the remaining one-third will be highly dependant on capillary trapping (Hermanrud et al., 2009). Since the CO_2 plume reached the caprock in 1999, there is currently no evidence that the CO_2 has breached it.

Other modelling variables under investigation include top seal topography, the number of feeder pathways and CO_2 properties.

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Rangely

Project Type: storage, EOR
Location: Colorado, USA
Start Date: 2000
Estimated Storage: 26 Mt

Injection Rate	4.5 Mm^3/day
Depth of Injection	1950 m
Reservoir Lithology	sandstone
Transport Method	pipelines
Porosity	12%
Permeability	8 mD
Formation and Age	Weber Formation (Permo-Pennsylvanian)
Thickness	160 m (58 m net)

Figure 55. Location and summary characteristics of the Rangely CO_2 injection site.

Overview

Rangely Field is located in NW Colorado (Figure 55) on the north plunge of the Douglas Creek Arch, between the Piceance and Uinta Basins. Hydrocarbon production is from the Permo-Pennsylvanian Weber Formation, which is about 1950 m underground. Accumulation is localized on an anticline of Laramide age. The Weber Formation interfingers across the structure into the arkosic Maroon Formation to the south.

The Rangely Field was discovered in 1933 and its sand unit is the largest in the Rocky Mountains. The field had 1,879 million stock tank barrels (MMSTB) of original oil in place and was developed in 1940, hydrocarbon gas was injected for pressure support in 1950's and unitized for water flooding in late 1950's. Since 1986 CO_2 has been used for Enhanced Oil Recovery in order to increase the field's commercial life. The field is currently being operated and owned by Chevron Texaco. Rangely CO_2 Project is aimed at accessing the fate of the injected CO_2 and to investigate microseepage: test and develop the microseepage detection methods. After monitoring and careful observation it was found that the risk of CO_2 up to the surface is low. CH_4 is gave a much greater cause for concern in that respect.

Site Characterisation

The field sits atop the Rangely Anticline, which is located on the NE flank of the Uinta Basin. At this location, the Weber Sandstone is the principal reservoir, accounting for over 98% of the total field production. The formation is overlain by a series of other sedimentary units, including the Mancos Shale on top of the sequence, followed by the Dakota, Morrison, Curtis, Entrada, Carmel, Navaho, Chinle, Shinarump, Moenkopi, and Park City formations (Figure 56).

The Weber Formation is Permian to Pennsylvanian (245-315 Ma), and typically consists of fine-grained, cross-bedded calcareous sandstones. Average thickness of the unit is 360 m, although the gross reservoir thickness averages 213 m, and the net production interval within the formation varies from approximately 15 to 120 m because the section consists of interbedded sands, silts, and shales of the Weber formation with tongues of shale, silt, and arkose of the Maroon Formation as shown in Figure 56. A littoral marine environment apparently predominated in this area during deposition of the Weber Formation, resulting in the formation of sand bodies of various depositional, complex multilayered and laterally coalescing sand units. The texture indicates a reworked mature deposit. Separating or forming laterally equivalent facies to these sand units are gray and red shales, red silts, and coarse maroon arkoses generally considered to have been deposited in a deltaic environment with a source attributed to the Uncompahgre Highlands to the south. Depth to the top of the Weber Formation in the Rangely Field ranges from about 1676 to 1981 m. Porosity and permeability vary within the Weber Formation and within the field. In general, porosity in the sand is estimated to average near 15%. Numerous anticlines and synclines deform the strata within the two basins. A major fault, the Uinta Basin boundary fault, lies in the subsurface near the northern margin of the Uinta Basin.

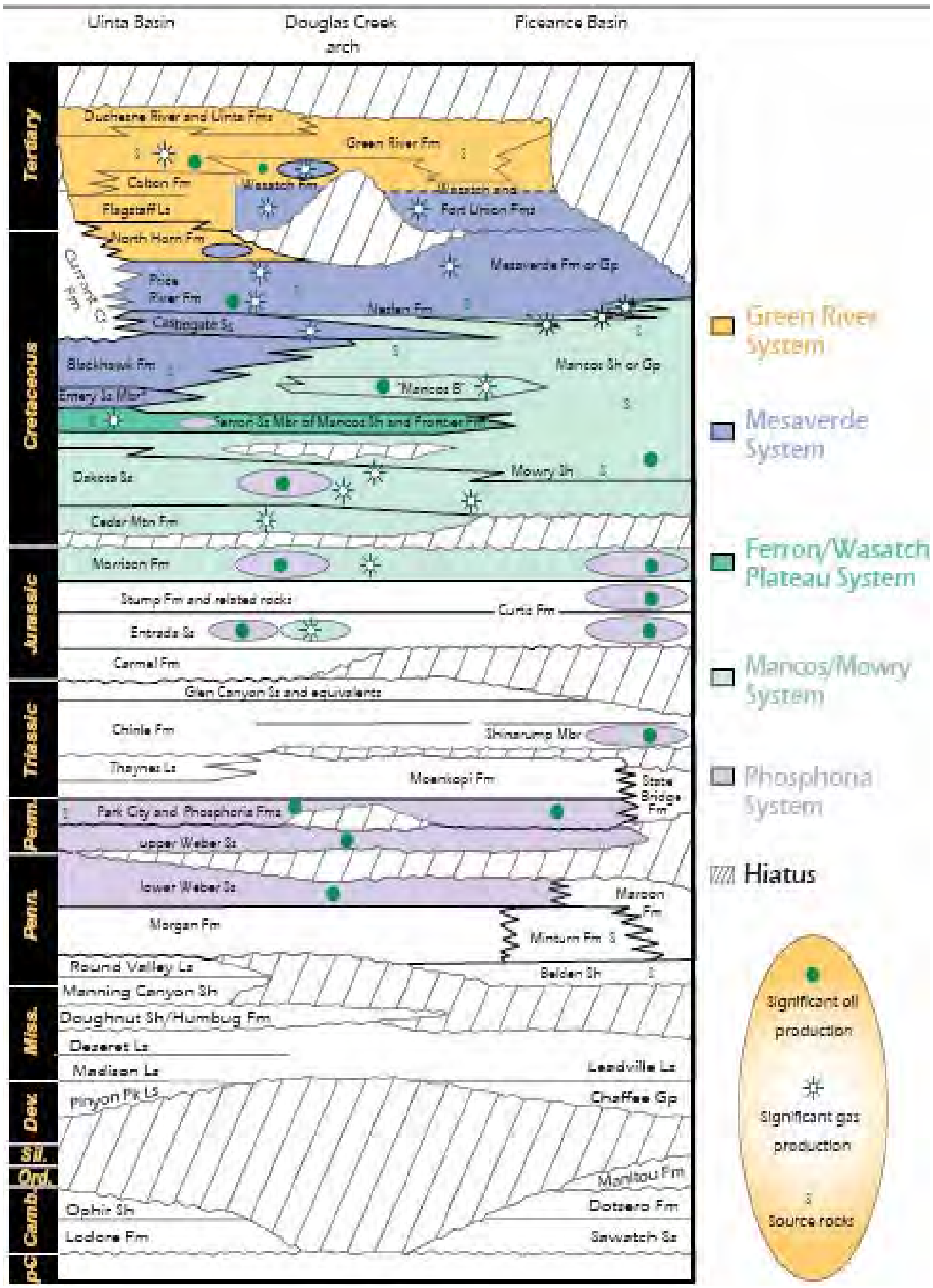

Figure 56. Stratigraphic column for the Unita-Piceance province showing major stratigraphic units, hydrocarbon occurrences and petroleum system defined in this province**.**

Pre-injection

The heterogeneity of the Weber Sand Reservoir required that a geological evaluation be considered with reservoir engineering to enhance primary and secondary recovery. The CO_2 for the project originates at Exxon's Shute Creek gas sweetening plant near LaBarge, Wyoming. The gas is transported via an Exxon pipeline 77 km to Rock Springs, where it is transferred to a Chevron Texaco pipeline which transports it the 207 km to the Rangely Field. Construction for the pipeline and injection process began in 1984.

Injection

CO_2 and water are pumped into the unit in alternating cycles and travel through the reservoir rock to drive the oil into the producing wells. The CO_2 is injected into the Weber sand (approximately 2000 m deep) at an injection rate of 4.5 million m^3/day through about 240 injectors. Consequently, an average of 14,000-15,000 barrels of oil/day is recovered via 340 wells. However, it has being observed that about 80% of the injected CO_2 comes back up through the wells. Noticeably, this amount has increased slowly as the age of the reservoir increases, which indicates that a percentage of the CO_2 is retained in the reservoir. According to computer modelling some injected CO_2 is dissolved in formation water as aqueous CO_2 and bicarbonate. The cumulative amount of CO_2 sequestered is 26 Mt.

Monitoring

Measurement of CO_2 and CH_4 soil gas concentration and exchange with the atmosphere was conducted directly across the Rangely Field in the summer and winter. During winter (which is characterised by minimum biological activity) the methane from deep source was detected and confirmed using ^{13}C and ^{14}C. CH_4 was estimated to be leaking at a rate 400 t/year, whereas CO_2 was less than 170 t/year relative to the control site.

Outlook and Issues

Methane will most likely be more of a problem than CO_2 in the CO_2-EOR operations because of its greater mobility, relative to CO_2. Measurements of this type will be more difficult to apply for purposes of detection of microseepage in warm and humid climate. The study on microseepage within the Rangely Weber Sand Unit ended in 2002, but the Rangely CO_2-EOR project is still operational.

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Gorgon

Partnership: GJV (Gorgon Joint Venture)
Project Type: storage, offshore saline aquifer
Location: Greater Gorgon Area, offshore NW Australia
Partners: Chevron, Shell and ExxonMobil
Time Scale: Approved: Aug 2009, Injection: 2014, Life span: 40 years
Estimated Storage: 129 Mt
Project Website: http://www.chevronaustralia.com/ourbusinesses/gorgon.aspx

Injection Rate	4.9 Mt/year
Depth of Injection	2700 m
Reservoir Lithology	fine grained sands and siltstones
Transport Method	offshore platform-platform pipeline
Porosity	20%
Permeability	25 mD
Formation and Age	Dupuy Formation (Upper Jurassic)
Thickness	200-500 m

Figure 52. Location and summary characteristics of the Gorgon CO_2 injection site.

Overview

The Gorgon Liquified Natural Gas (LNG) project is a Joint Industry Venture (JIV) between the operators Chevron (50%), Royal Dutch Shell (25%) and ExxonMobil (25%). The Gorgon Gas Fields, at around 145 km from mainland Australia (Figure 52), contain up to 14% natural CO_2 in the reservoir fluid composition. As CO_2 will solidify under the process of liquefying natural gas, it must be removed from the raw gas stream prior to processing. Rather than vent the CO_2 into the atmosphere, it is proposed that CO_2 will be stored in a saline aquifer, below the processing plant at Barrow Island, at around 2 km depth. It is estimated that a sum of ~120 Mt CO_2 will be injected within the life of the plant, with injection predicted to start in 2014 (Flett et al., 2009).

Site Characterisation

In order to minimise geological uncertainty, two techniques were utilised when characterising the reservoir proposed for CO_2 injection. Firstly, a pilot seismic study was conducted to allow for primary data acquisition. Although initial seismic work has been acquired in 2D, it will allow the ideal source/receiver positions to be established for future 4D seismic acquisition. Secondly, in 2006, an appraisal well was drilled to allow for a more comprehensive understanding of pore volume, injectivity and containment. This was accomplished using the following listed facilities of the appraisal well (Flett et al, 2009):

- modern open hole logging suite;
- wireline mini-frac and formation pressure testing;
- leak off test data;
- water production and well test data;
- vertical seismic profiling;
- 500 m of core through all stratigraphic units of the injection reservoir.

The targeted reservoir for CO_2 injection is the Late Jurassic sands and silts of the Dupuy Formation. Thought to have been deposited in a deep water slope, the clastic system is regionally extensive and now lies at around 2 km sub-sea. Although the Dupuy Formation can be split into four stratigraphic units, injection is only targeted at two of the most sand-rich units. The lower unit known as the Lower Dupuy is 90% fine grained sand (Flett et al., 2009) in the northern wells, but has higher shale content in wells to the south. The second target for injection is the blocky fine to medium grained sandstone known as the Upper Massive Sand. The unit also contains significant low permeability intra reservoir siltstones that will act as baffles in the reservoir.

The reservoir is capped by regionally extensive shale known as the Basal Barrow Group Shale. It is a deltaic shale deposit that is penetrated before the Dupuy Formation in every well drilled, and is therefore thought to provide a continuous barrier to CO_2 migration. The permeability of the shale, and therefore its sealing potential was tested with mercury injection capillary pressure analysis (Flett et al., 2008). A salinity contrast of 20,000 ppm NaCl equivalent was measured between the Dupuy Formation and aquifers above the seal, suggesting that there is at least one hydraulically compartmentalising seal.

Pre-injection

Prior to injection, reservoir simulation models have been developed to determine the maximum well injection rate while ensuring the containment of CO_2. Reservoir models have been constructed on a range of scales, with a prominent focus on permeability, reservoir connectivity and subsequently CO_2 plume evolution. Although initial models were static, dynamic modelling has now allowed an understanding of the most likely injection/migration scenario and subsequently will allow decisions to be made on the rate, location and number of injection wells.

Geomechanical modelling, based on pore pressures, leak off tests, mini-frac data, image log data, fault geometries and rock mechanics data, has also been completed. This will provide further constraint on the location and trajectory of injection wells along with feasible injection rates (Flett et al., 2009).

Injection

As the project is still in its early stages, with construction only starting on the 1st December 2009, the details noted below only reflect a development plan. Due to the relatively low average permeability of the reservoir, at 25 mD, it is proposed that to maintain an injection rate of 4.9 Mt/year (Malek, 2009), up to eight deviated injection wells will be needed. These will be drilled along side four water producing pressure management wells and four reservoir surveillance wells. Water producing pressure management wells are designed to minimise pressure build up around the injection plume in order to maximise the achievable injection rates (Flett et al., 2008).

It is predicted that the low permeability intra reservoir siltstones of the Upper Dupuy Formation will hamper migration to the top-seal, which is predicted to take up to 8000 years according to reservoir simulations. It is therefore predicted that residual and dissolution trapping will have a significant effect on permanently trapping CO_2 within the reservoir of the Dupuy Formation (Flett, 2008).

Monitoring

Monitoring techniques have again been assessed within the development plan to coincide with reservoir simulation to ensure responsible monitoring of the CO_2 plume. Monitoring techniques will be utilised via an array of various methods listed in the Table 6.

Table 6. Monitoring techniques to be used at the Gorgon CO_2 injection site (from Flett, 2009).

Injection Wells	-Well head pressure -Flow Rate -Continuous Down-Hole Pressure
Reservoir Surveillance Wells	-Saturation logs -Continuous down-hole pressure above injection interval
Surface Seismic	-3D baseline survey over plume area -Repeat 3D seismic and passive seismic
Surface Monitoring	-Soil gas flux sampling over seismic grid -Sampling at near surface seepage points

Outlook and Issues

The Gorgon Project is proposed to be the largest-scale CO_2 storage project in the world. Until injection commences in 2014 it is unknown as to whether stated injection rates will be achievable. The five greatest risks to successful injection as stated in the executive summary of the phase 3 of the development plan are:

- insufficient capacity for $CO_{2;}$
- inadequate containment of CO_2 in the reservoir;
- insufficient rates of injection into the reservoir;
- containment of other hydrocarbon resources by migration of CO_2 from the disposal site;
- commercial viability of the project.

If injection rates are achieved the Gorgon project will reduce net global greenhouse gas emissions by approximately 45 Mt/year (www.co2captureandstorage.info).

Located on Baffin Island, a 'Class A' Nature Reserve, the project is restricted to a 25 hectare zone. Although reducing the projects environmental footprint this limit adds significant challenge to the project in areas such as seismic acquisition. These problems can often be overcome however, such as the use of helicopters for managing drilling and recording operations.

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