THE PROCESS OF DEVELOPING A CO_2 TEST INJECTION: EXPERIENCE TO DATE AND BEST PRACTICE

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Key Messages

- Data from 45 small scale projects and 43 large scale projects have been compiled in order to extract learnings and best practice guidelines were reviewed.
- No project is the same, and there is not a perfect template, however lessons learnt from previous projects can be applied to new projects.
- There needs to be an agreed and well defined workflow with clear decision points.
- At a very early stage, there needs to be very clear protocols for data collection, use of samples, input into databases, publication and dissemination of scientific outcomes.
- Key performance indicators need to be agreed with the regulators so that objectives of monitoring are clear.

Background to the Study

There are a significant number CO_2 injection sites around the world of varying size, all of which could provide useful learning experiences for anyone attempting their first test injection. Many projects will have gone through project planning, risk assessment, permitting processing etc; the learnings of which may be useful for future projects.

The purpose of this study is to document experience of the development of CO_2 injection projects in order for countries looking to embark on their first CO_2 test injection to refer to. This first test injection is considered to be in the order of 10,000 t CO_2 per year. They will then be able to refer to the experience and lessons learned through the development and operation of CO_2 test injection projects elsewhere in the world.

The initial stages of any injection project will be a desk based assessment and initial site selection, followed by exploration and detailed site characterisation, obtaining permitting for injections and setting out a monitoring plan.

Every storage site will have gone through various stages and processes before injection can start. These will differ depending on the size, location, local regulations and the geology of the site. However, the processes, if not the details may be common amongst all sites, including site characterisation and license permitting (though regulations will vary throughout regions). Many CO_2 demonstration sites have been the first of their kind and regulations and permitting have developed alongside the project. For a country hoping to start their first injection it would be useful to be able to access one document that outlined the whole process with a timeline and pointed to relevant sources of information.

There are several best practice documents and guidelines available; these vary in scope and technical detail. A number of non-site specific best practice guides have been produced, such as NETL's risk assessment and site selection manuals and WRI's CCS guidelines that outline the entire process. There are also best practice guidelines considering learnings taken from particular projects, such as the SACS, best practice for the storage of CO_2 in saline aquifers, which uses, amongst others, learnings from the Sleipner storage site in the North Sea. Other examples of best practice guides are the QUALSTORE best practice guide and the EU Guidance documents. There are several documents outlining issues regarding public communication including guidelines from NETL and WRI. The Global CCS Institute recently commissioned CO2CRC to produce a summary of best practice guides, including a summary of the varying areas of coverage and technical detail. The document is publically available on their website: http://www.globalccsinstitute.com/publications/review-existing-best-practice-manuals-carbon-dioxide-storage-and-regulation.

CO2CRC, a consortium based in Australia was commissioned by IEAGHG to undertake a study compiling learnings from test injections.

Scope of Work

This study does not intend to redo work already carried out, but to produce an over-arching document, which follows the process of setting up a test injection. This document would identify gaps in best practice guides as well as point readers towards available information. The document produced would order the steps and processes that the user would need to go through during the management of the test injection; from scoping of the project (including success criteria), site selection, planning, injection and closure. Many of the steps will happen simultaneously, but an order can still be established along with an expected timeline. This would be broad enough to allow for different permitting and legal processes in different countries as well as different site specific technical issues.

The study was suggested to be carried out in 4 parts;

The first part will be the identification of test injection projects. To date there has been a significant number of CO_2 test injection projects conducted around the world including: Frio, Otway, Ketzin, Nagaoka, as well as a significant number of US Regional Partnerships Phase II projects. Each of these projects would have to have gone through significant planning and development before entering into operation. The projects identified should have relevance to pre-commercial CO_2 test injections and pilot projects in the order of 10,000 t CO_2 per year.

The second part will be the identification of key development issues. For each project identified it would be valuable to document development information around project scoping, development of success criteria, project planning, planning a monitoring program, site selection, risk assessment, public engagement, legal and regulatory requirements, permitting, scheduling, costs, funding, staffing, skills required, management processes, reporting, reviewing and any unexpected hurdles and their solutions.

The third part will be looking at trend analysis. Once information is gathered, trends across projects could be analysed identifying what processes are common across projects and when and why processes may differ.

The fourth part will be the development of a test injection manual or best practice guide. Once information from existing projects has been gathered and trends analysed, a CO_2 test injection development manual could be produced. This will be an overarching document with all the steps needed in the process of setting up a test injection.

A follow-up of this work is the possibility of producing a webtool, whereby users will be able to enter information they have and be able to access the appropriate parts of the guide as well as relevant reference documents. This work will not be part of the current study, but the contractor was asked to keep this in mind when producing the guide.

CO2CRC were asked to refer to the following recent IEAGHG reports relevant to this study, to avoid obvious duplication of effort and to ensure that the reports issued by the programme provide a reasonably coherent output:

- Injection Strategies for CO_2 Storage Sites (CO2CRC, 2010/04)
- CCS Site Selection and Characterisation Criteria (Alberta Research Council, 2009/10)
- Global Storage Gap Analysis for Policy Makers (Geogreen, 2011/10)
- What we have learnt from large scale demos, phase 1 and 1b (IEAGHG 2009/2011)

Findings of the Study

Information from 45 small scale injection projects and 43 large scale injections projects have been compiled in order to look at trends and put together learnings. Small scale projects were considered to be those injecting less than 100,000 tonnes, though the majority of projects inject considerably less (<15,000 tonnes).

Key Development Issues

A decision pathway for any project, including small scale projects, is needed, such fig. 2, where there will be defined decision points which may be dependent on availability of funds, regulatory approval, risk assessment and geological suitability. How closely such a pathway is followed appears dependent on the project and those with an industrial partner may be more likely to follow closely, however there generally appears to be more flexibility with small scale projects than with larger ones.

Figure 2 The generalised project decision pathway

The first phase ‘identify and assess’ can take from between a few months to several years, depending on the starting point of a project. A project can start from a desktop study and compilation of possible options, though often it can depend on where CO_2 is available or if an oil company makes a site available for injection.

The ‘select concept phase’ aims to narrow down the site options to one (possibly with backup options) by developing a higher level of confidence of several factors including geology, logistics, cost and regulations. This is the phase where contact with the regulator is necessary and if there are not already regulations in place a set of key performance indicators (KPIs) may need to be agreed. There should also be communication with stakeholders, including the local community. This phase is usually 1-2 years.

The ‘define’ phase will further reduce uncertainty and define and finalise the project scope enough to take the project to the final investment decision (FID). The time scale will vary greatly with the complexity of the project; if an existing operator has control, possibly a matter of months, otherwise a minimum of a year should be expected.

The ‘execute’ phase happens after the FID and construction and equipment installation can take place. Necessary systems for approvals and cost controls need to be in place and in the case of a greenfield site; this phase will take around 12 months. This concluding act of this phase will usually be injection of CO_2.

Provided the previous phases have been undertaken carefully and all permits are in place, the ‘operate’ phase should run smoothly. It is necessary in this phase to draw up plans for abandonment. The timing of this phase will depend on the objectives of the project.

The ‘abandon’ phase includes the stages of suspension, closure and abandonment. Suspension is temporary and may be of short duration, but the decision to close the site has implications for decommissioning and KPIs may need to be agreed with the regulator. Abandonment will involve plugging and abandoning any wells, unless they will be used for some other purpose. Required monitoring after closure, will depend on the regulator as will liability transfer.

Trends in project development

Projects can only be compared in a general way, as they are all different and there are also only a limited number. When looking at the geographical distribution it can be seen that the majority exist in North America, partly due to the success of the Regional Carbon sequestration Partnership Program and partly due to the availability of CO_2 for the purposes of EOR. There are also often fairly pragmatic reasons for the general location of a project, though obviously the geology is always a factor.

The main purpose of projects is demonstrating storage, but there is not always a clear statement of project objectives, and though 1/3 of projects are labelled as research, the specific purpose is not often given. The objectives of a project may also change over time.

Projects have a range of ownership and governance models, with 23% energy company owned, 17% by government, 16% by a single research organisation and 44% by a research alliance. Even if a project is owned by a single organisation, most projects involve collaborative arrangements between organisations, which can be a mix of industry, government, research bodies and academia. There does not appear to be a preferred structure within small scale projects, though it is important to have a clear governance structure and decision making process, so that risks can be managed.

Funding arrangement information for the projects is not always easy to find, though it has been determined for the projects, though comparison is difficult as costs are often done on a different basis, however costs appear to range from $1 million to $100 million. A major difference with a small scale and a commercial project is funding, whereas a commercial project will not start until all money is confirmed, a research project often has funding uncertainties throughout the first half of the decision chain. This is often due to first-of-a-kind projects with no early basis for budgeting.

Reservoir lithology and storage type were compared, with the majority into sandstones and deep saline aquifers, there was also a significant amount into coalbeds, depleted oil and gas fields and EOR. This roughly parallels large scale projects, except for ECBM, though this may be due to small scale projects showing it not to be viable for large scale testing.

The majority of CO_2 is from natural sources, followed by gas processing, with only a very small percentage from CO_2 capture from combustion. The majority is also transported by truck. These decisions seem to be mostly based on cost and where a combustion source is used it is to show proof of concept. Sourcing the CO_2 is a critical component of any project and will have financial, locational and logistical implications for the project.

Project lead time was also compared and there was not seen any obvious trend, and no 'learning curve over time' was discerned. It was also difficult to compare due to different ideas on when the concept of a project is. There are also often issues, such as stakeholder agreements, which will be different for each project.

Learnings from Case Studies

Projects where particular technologies or approaches have been successfully applied, have been used as case studies to extract more in depth information regarding site characterisation, modelling, monitoring and risk assessment.

Site Characterisation

Most small scale projects do not follow the theoretical pattern of project development that has been suggested in the literature as being optimal for large commercial scale operations. Generally, small scale projects are opportunistic, typically initiated by research organisations; they rely on an alliance with industrial partners for operational expertise and access to suitable locations, site selection and therefore depends very much on which sites can be made available

Most small scale projects are located in brownfield sites where a pre-existing database can help to minimise the extent of pre-injection characterisation necessary. Pre-drill reservoir characterisation typically consists of the integration of pre-existing geological and hydrological data. The degree to which new data is collected for this purpose varies but generally seems to be quite small. Drilling purely for stratigraphic information is rare, with most projects only drilling the intended injection well, though it will generally be sampled to supplement the existing dataset, typically acquiring data on the sealing formations which are frequently not sampled in standard petroleum developments.

Storage sites within depleted fields or with an EOR component may only need minimal site characterisation, but deep saline reservoirs will usually be data deficient and require project specific data collection even when these reservoirs are located within the footprint of an existing production project.

The degree of pre injection site characterisation that pilot scale projects have engaged in varies considerably. The variability reflects the range of sites chosen for the experiment, including the availability of prior data, and the type of storage being investigated. Progress to larger scale demonstrations or full industrial scale projects will require a more extensive prior characterisation of the proposed site, and more exhaustive modelling than is seen in most small scale projects. Larger projects are also likely to benefit from early pilot scale projects.

Modelling

Reservoir simulations are performed routinely to assess CO_2 injection tests and provide valuable information for system design, permitting, and monitoring. The simulations are also useful for some less obvious functions including provision of a systematic framework for integrating site characterisation data; as a communication tool to help people better understand CO_2 storage; and building confidence in the CO_2 storage process if the models demonstrate that the project is thoroughly researched, well designed, and properly operated.

In most published cases, models provided an adequate simulation of the CO_2 storage process, particularly in the prediction of the pressure response during injection. However, very rarely could the models fully describe the entire CO_2 storage process.

In most cases, projects follow a generalised workflow for reservoir simulations which consists of:

- Analytical injection model and volumetric storage capacity estimations during site screening.
- Simplified, possibly 2D-radial, scenario modelling using homogeneous parameter distributions including uncertainty analysis during the pre-feasibility phase of a project. Model parameterisation is based on pre-existing and literature data.
- Predictive modelling of the injection process in specific reservoir intervals during the detailed site characterisation phase. Additional data from core analysis, logging and initial well tests are used to better constrain reservoir parameters. Well test (i.e. brine injectivity test) will provide data for initial model calibration.
- Model calibration and validation during the injection and post-injection phases. Measured data from the M&V program are compared to model predictions and the

model is continuously updated resulting in improved confidence in the model's predictive capability.

As in any other modelling field, the type, resolution and dimension of the reservoir model should be appropriate to the specific requirements and objectives of a project. Reservoir models associated with pilot projects that have research objectives related to the detailed behaviour of CO_2 in the subsurface (dissolution rates, residual saturation, CO_2-water-rock interactions) may require high resolution models and extensive computational effort. However, depending on the complexity of the subsurface, a simple 2D radial model may be sufficient to predict the maximum plume extent and, in conjunction with M&V, satisfy regulatory requirements for a relatively simple test to demonstrate safe injection and storage of CO_2. The more detailed and calibrated modelling results from pilot injection projects can be matched with (semi-) analytical or simple 2D models that are less data intensive and require less numerical effort, the higher the confidence in providing an adequate modelling process that is time- and cost-effective.

Monitoring

Monitoring is used primarily as the basis of assuring that undesired or unexpected events that are identified in the risk assessment of the project, and that the likelihood of them occurring is not increasing. Though other objectives include pre injection monitoring for developing site baselines and adding to the data collation in site characterisation; and varied assessment of the storage activity relative to performance targets and reporting requirements, providing modelling calibration and storage effectiveness guidance.

However, for test injection activities, where R&D on monitoring technology may be a focus, knowledge of processes in the sub surface becomes vital, and can be extended to include understanding the performance and limitations of monitoring technologies in assessing these processes. Therefore monitoring in test injection projects may be used for a variety of purposes. This may include monitoring (and benchmarking monitoring techniques) for spatial distribution of injected fluid or changes in fluid saturations; geomechanical and structural events/changes to the subsurface; physical/chemical changes to injection interval and overburden; and/ or physical/chemical changes in the near-surface/surface/atmosphere.

Baseline monitoring to establish natural variability should be undertaken as soon as the evaluation of the site commences and certainly well before injection of CO_2 is initiated. Project monitoring should take place as soon as changes are made in the subsurface, typically associated with the start of injection of CO_2. In the case of EOR or ECBM, project monitoring may start with the production of hydrocarbons rather than the start of fluid injection. However, there are many considerations required in developing effective monitoring operations and the planning for monitoring ideally should start no later than early within the evaluation stages of a CO_2 storage project.

For many of the test injection projects, the planning for monitoring commences at the very onset of the opportunity definition, as a key purpose of a test project typically includes R&D into monitoring technologies. Field trials of the effectiveness of particular monitoring techniques falls within the evaluation stage, so that findings (including realised technology restrictions), can be considered in the more mature monitoring plan. When projects require monitoring of the biosphere; seasonal variability and related factors typically require long term biosphere characterisation, which needs to start at the start of the “Define” stage. The commencement of the project build phase typically coincides with the deployment of the majority of the monitoring infrastructure (such as dedicated observation wells) and the commencement of baseline monitoring (such as initial 4D seismic). Monitoring of the performance of the CO_2 injection will typically extend beyond the conclusion of CO_2 injection, with the time depending on the requirements of the regulator and match between modelling and monitoring results. Assurance monitoring is likely to continue through to near the end of the closure of the project, again depending on regulatory requirements. In some circumstances assurance monitoring may be continued by the regulator or some designated body, post closure.

Risk Assessment

Information and documentation for risk assessments for test injection projects was very limited. In some cases this may be due to this being carried out by the industrial partner and the research organisations not having access, in some cases it may not be published. Otway was used as a case study as all information was available.

The risk assessment is updated throughout the project. The risk response plan resulting from risk assessments evolves along with the stages of the test project’s characterisation through to operation and monitoring observations. Early in the project’s characterisation and data acquisition stages, a risk targeted-uncertainty reduction process should take place. In ideal cases the development of a field for a test injection project provides an opportunity to collect much of the necessary data for some uncertainty reduction, such as a sampling and logging program to accompany the drilling of the injection or monitoring well. However, in some cases, if risk levels warrants and budget allows a targeted uncertainty reduction characterisation program may be required. It is at points such as these that risk- and cost-based decisions on project continuation may result in major project changes or project cancellation.

As a project progresses towards execution and operation, working thresholds are able to be established to assure risks associated with containment and performance are maintained at an acceptable level. Understanding these thresholds assists in forming the basis of the monitoring plan in terms of capabilities of technologies to determine whether these thresholds are being approached. An example of this is fracture pressures, where a reasonable uncertainty range should be developed according to the existing data, a pressure threshold determined, iterative modelling of pressure to injection design so that maximum pressure is comfortably below the threshold, a pressure monitoring system designed installed, and an operational response plan developed if pressure approaches the threshold.

During the operational stages all risks should either be sufficiently below an acceptable risk level or have contingency measures in place to respond to an undesirable event taking place.

The level of cost and effort applied to a risk response and monitoring plan should be based on the assessment of that risk with all its likelihoods and consequences considered. In all cases the project activities should follow appropriate industry standards and best practices in the management of risk.

Figure 1 shows a compilation of features from the small scale projects, though it is important to note that this does not aim to be statistically meaningful, or to show what a project should entail, but should give some idea of general features and may be useful at the earliest stages of developing project concept.

Figure 1 Project parameters according to types of projects

PROJECT PARAMETER	PROJECT TYPE				
	DSA	EOR	DOGF	ECBM	Basalt
Max Number of Projects	18	9	4	11	2
Time (start of injection) (years)	3	2-3	3	3	5-6
CO_2 Source	Multiple	Geological	Natural Gas	Multiple	Food/Magmatic
Transport	Mainly truck	Pipe + Truck	Onsite	Truck	?
CO_2 injected (tonnes)	15,000	20,000	64,000	2,000	2,000
Injection Rate (tonnes/day)	127	74	84	31	36
Injection Pressure (psi)	1,662	1,240	1,980	1,995	362
Injection Depth (m)	1,600	1,600	2,900	700	700
Cost US$	12	12	60	6	17
Percentage of Projects Using the Specific Technology					
Downhole Seismic	100	40	100	40	50
Groundwater Monitoring	70	80	50	80	100
Soil Monitoring	40	100	70	30	100
Atmospheric Monitoring	60	60	50	30	100
Biological Monitoring	20	0	20	40	100
Tracer Analysis	40	40	20	60	100
Electromagnetic	20	10	0	0	0
Gravity	0	20	0	0	0
Pressure Logging	100	70	100	100	100
Thermal Logging	90	60	100	100	50
Wireline Logging	90	70	80	40	100
Observation Well	60	40	80	80	50
Geochemical	80	60	100	100	100
INSAR	0	0	0	10	0
Reservoir Modelling	90	90	100	100	100
Coring	100	60	100	100	0
Reflection Seismic	100	60	100	60	0
Geological Model	90	80	100	90	50

Best Practice

Best practice guidelines were reviewed, while few cover the entire chain, the more specific guidelines tend to cover particular aspects in more detail. So it may be best to use guidelines together, or focus on the ones which cover the aspect being researched. Figure 3, shows the level of detail that can be found for specific aspects, more details of where to find the guidelines are given in the report.

Figure 3 Scope and content of some best practice manuals

	Pre-feasibility	Site Selection	Capacity Estimation	Simulation and Modelling	Construction	Operation	Closure	Monitoring and Verification	Risk Assessment	Community Consultation	Regulation
SACS	Basic	Technical	Technical	Technical	-	Basic	Detailed	Technical	Detailed	Basic	Basic
NETL (SS)	Basic	Detailed	Technical	Basic	-	-	-	-	Basic	Basic	Detailed
NETL (RA)	-	-	-	Technical	-	-	-	-	Technical	-	-
NETL (MV)	-	-	-	-	-	Technical	Technical	Technical	Basic	-	Basic
NETL (GS)	Technical	Technical	-	-	-	-	-	-	-	-	-
NETL (PO)	-	-	-	-	-	-	-	-	-	Technical	-
WRI (CCS)	Basic	Detailed	Basic	Basic	Basic	Basic	Detailed	Detailed	Detailed	Basic	Detailed
WRI (CE)	Basic	Basic	-	-	Basic	Basic	Basic	Basic	-	Detailed	Basic
DNV	Detailed	Detailed	Detailed	Basic	-	Detailed	Detailed	Basic	Detailed	-	Detailed
DNV (Wells)	Detailed	Detailed	-	-	-	-	-	-	Technical	-	-
CO2Cap	-	Basic	Basic	-	Detailed	Detailed	Basic	Technical	Basic	-	-
GEOSEQ	-	Basic	Basic	Basic	-	-	-	Detailed	-	-	-
CO2NET	-	Basic	Basic	Basic	-	Basic	-	Basic	-	-	-
IEA	-	-	-	-	-	-	-	-	-	-	Technical
CO2Cap (R)	-	-	-	-	-	-	-	-	-	-	Technical
MRCSP	Basic	Basic	-	Basic	Technical	Technical	-	Technical	-	-	-
CO2Care	-	-	-	-	-	-	Technical	-	-	-	-
GCCSI/ICF	Detailed	Basic	Basic	Basic	Basic	-	Technical	-	-	Basic	Basic
CO2CRC	Detailed	Detailed	Basic	Detailed	Detailed	Detailed	Basic	Detailed	Detailed	Detailed	Detailed

-	Not Covered
Basic	Briefly covered in a generic way
Detailed	Comprehensive discussion, generally generic
Technical	Provides technical detail of projects, generally comprehensive

NETL (SS)	Best Practises for: Site screening, site selection, and initial characterization for storage of CO_2 in deep geologic formations
NETL (RA)	Risk analysis and simulations for geologic storage of CO_2
NETL (MV)	Best Practices for: Monitoring, verification, and accounting of CO_2 stored in deep geologic formations
NETL (GS)	Best Practices for: Geological storage formation classification: Understanding its importance and impacts on CCS opportunities in the United States
NETL (PO)	Best Practices for: Public outreach and education for carbon storage projects
WRI (CCS)	Guidelines for CCS
WRI (CE)	Guidelines for community engagement in CCS

Observations from test injections considered in this study, show that collaborative agreements may be necessary at this stage of development and realistically a significant level of financial involvement from government is required. Another common thread in virtually all projects is to link research institutions with industrial partners, in order to advance the science with practical field based trials (with the industrial partner proving the operational experience).

Expert Review Comments

Comments were received from 9 reviewers representing industry and academia and were overall highly positive, with all reviewers agreeing on the usefulness of the work. Comments included updates on projects, clarifications on the terms used in the decision pathway, improvements to some diagrams and inclusion of a summary expressing the use of small scale pilot projects. This was all addressed in the final report.

Conclusions

This study provides an indication of how a project might be organised and undertaken, the conditions that might prevail (depth, amount of CO_2 likely to be injected, injection rate, timing, cost) and the range of technologies that should or might be deployed, though these parameters will vary depending on the objectives of the project and the particular features of the site.

As well as the learnings derived from the project compilation, any new injection project should use the information available from previously written best practice manuals and guidelines. The guidelines reviewed in the study are project based, often focused on different aspects of a project and vary greatly in the amount of detail given. There is no single all-encompassing “best practice” for small scale projects that can be followed to the letter. Rather there are many lessons to be learned from the 45 small scale projects that have been reviewed in this report which will be applicable to other projects to varying degrees.

The objectives of the project must be agreed and clearly defined in a manner that addresses the expectations of all key stakeholders, whilst recognising that as a research/pilot project, not all objectives will necessarily be achieved. For this reason, it is also important to also prioritise objectives as well as retain the necessary degree of flexibility so that if there are unexpected outcomes, objectives can be modified or re prioritised in a sensible manner. If the project is being undertaken by a consortium, ensure that there is full alignment between all participants on issues such as budgets, funding, responsibilities, liabilities, governance, confidentiality, communications, operations and management and board responsibilities. To the extent possible it should be ensured that there is alignment of funding, budgets, and the expenditure profile over the life of the project.

There needs to be an agreed and well defined work flow with clear decision points to enable the project to be logically taken from identification of the opportunity through to the operate stage and finally the abandon stage. There should be agreement on how and on what basis the project will be abandoned at the conclusion of the project including ensuring that there is adequate funding available meet abandonment (including remediation) requirements.

Engagement with the local community should be at the earliest possible opportunity; ensuring that they learn about the project from members of the project and not from the media. A local liaison officer or community officer, who lives in the vicinity of the site and who can act as the first point of contact, but at the same time ensure that the opportunity is there to talk directly to the scientists and engineers and establish an open and transparent approach to all aspects of the project. Also a broader communications strategy should be in place, at the regional national and international levels, for the project, particularly once it starts moving towards the operational phase, in order to provide positive stories on the project to the media and also to address any incidents at the site, should they occur.

Key performance indicators will need to be agreed with the regulators, so that objective of monitoring are clear and to ensure that the project can confidently move forward in the knowledge that the “ground rules” will not change in the middle of the project. Where regulations already exist ensure that will meet the needs of the project, and that you can meet the requirements of the regulations.

Comprehensive characterisation of the site needs to be undertaken and a system in place so that all models are updated as new information becomes available. Characterisation should include a broad understanding of the geological setting of the site including depositional environments of reservoirs and seals, structural setting, geomechanical properties, seismicity, ground waters (dynamics and composition), geological and reservoir models.

There should be a monitoring regime that will deliver data to address key performance indicators, address regulatory needs, meet community expectations and provide assurance to the community. Though before injection takes place, baseline data should be collected and there needs to be adequate knowledge of natural variability, both temporal and spatial, for all key parameters.

Risk assessment and management should be embedded within all aspects of the project including research, monitoring and operations.

The closure and abandonment stages of small scale projects are in general not well documented; it is important the information relating to these concluding activities is captured and made available, including information on any post closure monitoring.

Recommendations

A great deal of effort has gone into compiling data for all of the projects considered in the study and they have been placed in a useable format. The information is very relevant and useful for any new project and also existing projects to see what learnings there are from different projects. It is therefore recommended that IEAGHG make full use of this data by compiling a searchable database and hosts this information on the website. If this cannot be carried out internally, it is suggested that this be contracted out. This information should also be updated on a regular basis, which could be by utilising the contact details on the data sheets.

REPORT

Developing a small scale CO_2 test injection: Experience to date and best practice

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IEA Environmental Projects Ltd.IEA Greenhouse Gas R&D Programme

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CONFIDENTIAL

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1. Executive summary

In this review of small scale injection projects, information has been compiled on a total of 45 projects from around the world, ranging in scale from a few hundred tonnes of CO_2 to approximately 70,000 tonnes. The Report documents the experience of these projects and the lessons learned, with the objective of assisting countries or organisations wishing to embark on their first CO_2 injection test. The documentation available from these projects is variable in scope and detail. There are various reasons for this but hopefully this IEAGHG study will help new players in the CCS space develop CO_2 injection and storage projects at a scale of up to 10,000 tonnes of CO_2 or more, in a cost effective, time efficient and safe manner, drawing on lessons from the small scale CO_2 storage projects documented here.

In addition to the compilation of existing test injection projects (completed, operational and planned projects) the Report seeks to identify key development issues for projects and how they have evolved over time; identifies trends in project development as well as similarities and differences between projects; documents examples of projects and seeks to identify the important factors in successful projects.

Data sheets were compiled for the 45 small scale projects and a comprehensive summary database was developed as a prelude to the analysis of the similarities and differences between projects. The decision-making process of most projects is poorly documented and therefore a generic (industry-type) flow chart is used which approximates to the process that many projects adopt, commencing with the development of the concept to final abandonment, with key interim steps outlined, such as the basis for decision to move to front end engineering design (FEED) or to final investment decision (FID). It is clear from the study that the ‘classical’ flow chart, which starts with a major overview of a large number of sedimentary basins before finally focussing in on the preferred site, seldom works that way. Few projects start with a blank sheet of paper! More often than not, the site for the project is pre-ordained for a variety of reasons and it is more a matter of “making it work” or if this is not possible, of abandoning it. Most commonly the injection occurs at a “brownfield” site where there is information already available, rather than at a “greenfield” site, where there may be little or no information available. However this varies with the type of injection project, with injection into deep saline aquifers more likely at a greenfield location.

Small scale projects are undertaken for a variety of reasons. First and foremost they provide real world experience of CCS operations, to industry, government and researchers at a modest cost. Some of these are undertaken with the clear intent of it providing the lead-in to a much larger project; others are undertaken with no such intent. Some projects are planned to not progress beyond the small scale either because of lack of funding or because there is insufficient storage capacity, or because approval for a large scale injection will be difficult or unlikely to be forthcoming. Nonetheless the small scale injection does provide tangible evidence of proof-of-concept. A related but further reason for small scale experiments is to provide the opportunity for stakeholders, including the broader community, NGOs and other interested groups to be able to visit the project and “kick the tyres”. This is a powerful counter to the criticism that the technology is “unproven” as well as providing clear evidence that governments and industry are demonstrably active in undertaking measures to decrease emissions. The opportunity to test new technologies – for detection of leakage for example- can also be provided at low cost through small scale projects. Finally, the search for knowledge is an important driver of many small scale projects, with researchers eager to better understand CO_2-rock sub surface reactions, or to be able to better model CO_2 migration in porous media. For all of these reasons, small scale projects are, and will continue to be, an important component of taking CCS forward to the fully commercial and widely-deployed phase.

Every small scale injection project is different and there are only a limited number of projects to compare and contrast. What is clear is that the majority of small scale projects have been successfully undertaken in North America, with Australia and Japan, China and the European Union each having undertaken one or two small scale projects. In most countries, projects are undertaken through industry-government-research consortia, with a range of governance structures. Costs vary greatly from less than $1 million to $100 million, but accurate costing data is very difficult to obtain and the mean cost is more likely to be in the range of $15-20 million. Half of the projects are based on injection into sandstone reservoirs, although a significant 28% involve injection into coals. The source of the CO_2 is quite variable; the majority of the CO_2 is transported by truck to the site – a reflection of the cost effectiveness of road transport for a small amount of CO_2. Most projects inject less than 10,000 tonnes of CO_2, with less than one-quarter of the projects injecting more than 10,000 tonnes. The depth of injection ranges from approximately 300m to over 4000m but averages around 1200m. The time taken from making the preliminary decision to undertake a project to injection of the first molecule of CO_2 is variable but averages approximately three years.

Documentation of examples of projects is done on the basis of particular activities (site characterisation, reservoir modelling, monitoring and risk assessment) rather than trying to use one project as the “perfect” example or prototype, not least because no single example exists. In terms of site characterisation, Sumner County, Otway, MRCSP, SACROC and Carbfix, are used as examples and most illustrate the point that small scale projects do not follow the theoretical pattern of project development that has been suggested in the literature as being optimal for large commercial scale operations. Generally, small scale projects are opportunistic, typically initiated by research organisations; they rely on an alliance with industrial partners for operational expertise and access to suitable locations and site selection therefore depends very much on which sites can be made available. In most small scale projects, pre-drill reservoir characterisation typically consists of the integration of pre-existing geological and hydrological data. The degree to which new data is collected for this purpose varies but generally seems to be quite limited. Drilling purely for stratigraphic information is rare, with most projects only drilling the intended injection well, though it will generally be sampled to supplement the existing dataset, typically acquiring data on the sealing formations which are frequently not sampled in standard petroleum developments. Storage sites within depleted fields or with an EOR component may only need minimal site characterisation, but deep saline reservoirs will usually be data deficient and require project specific data collection even when these reservoirs are located within the footprint of an existing production project. Generally it does not appear that the majority of projects have felt the need for static geological models although this may be due to under reporting of the pre-injection workflow. However most do appear to have constructed dynamic models using known characteristics of the subsurface to assess migration pathways, but it is not always clear whether these pre- or postdate the drilling of the injection well or injection itself.

Reservoir simulations are an important element of the workflow associated with most CO_2 injection projects. Reservoir models for injection pilots are used to design the injection test, predict plume and pressure behaviour for permitting by the regulator and design an appropriate monitoring and verification scheme. A variety of codes are used to do this. Key points in good practice reservoir modelling are illustrated through the K12B, Otway, Pembina, Frio, MRCSP and Nagaoka Projects. Reservoir simulations are performed routinely to assess CO_2 injection tests and provide valuable information for system design, permitting, and monitoring. The simulations are also useful for providing a systematic framework for integrating site characterization data, visualization of model results provide a valuable communication tool. Reservoir simulations can build confidence in the CO_2 storage process if the models demonstrate that the project is thoroughly researched, well designed, and properly operated. In most published cases, the models provided a reasonable simulation of the CO_2 storage process, particularly in the prediction of the pressure response during injection. However, very rarely could the models describe fully the entire CO_2 storage process.

Commercial-In-Confidence

Monitoring is the third key step of the subsurface storage workflow. It is used primarily to assure that undesired or unexpected events that are identified in the risk assessment component of the project are not occurring and that the injection is behaving as planned or to understand the deviations from the predicted response. In other words, to confirm that geologic CO_2 storage is effective, that CO_2 is not leaking from the storage site, that it is remaining within the storage formation and not migrating to the near-surface environment, and that it is not seeping out of the ground. The examples used in this section of the Report are Ketzin, Otway, Pembina and MGSC. The monitoring programs for the test injection projects were opportunistic, utilising existing data for establishing a baseline for the monitoring, and also using existing wells for down-hole observations and monitoring-based sampling. Nearly all projects undertook pressure and temperature monitoring as a standard for the projects. Some general trends were noted in the type of monitoring used in relation to the storage type across the test injection projects. Deep saline aquifer storage more commonly utilises geophysical techniques, particularly seismic, to understand the areal distribution of the injected CO_2. Depleted hydrocarbon fields, EOR and ECBM, being more brownfield sites, commonly had a stronger understanding of the subsurface geological structure and most did not require extensive extra monitoring techniques. Instead these styles of storage sites focused on geochemical monitoring to understand the performance of the container fill (depleted hydrocarbon fields) or the enhanced recovery process (EOR and ECBM). The application of new (novel or emerging) monitoring techniques was patchy, independent of the storage type, and most likely depended on the available budget in the project. Most of the small scale test projects have not been developed specifically for CCS monitoring RD&D. In most cases a set of 'standard monitoring techniques' have been applied to assist in the delivery of the project's primary objective 'storage demonstration'. However in some of these projects, when the financial scope allowed, additional monitoring to further the RD&D on CCS monitoring has been successfully undertaken.

Documentation of storage risk assessment for test injection projects, was very limited indeed despite its perceived importance by regulators and other key stakeholders importance. One of the few documented uses of risk assessment in a small scale project is that of the Otway Project and therefore this example was used in the Report. A key objective of the Otway Project (and many other projects), was the demonstration of safe and effective underground storage of CO_2. The achievability of such containment was assessed via risk and uncertainty analysis, which considered the occurrence of unlikely events inducing leakage. Due to the nature of subsurface leakage, a specific risk analysis technique was applied to containment risk. This assessment strongly relied on the characterisation of the subsurface, fluid flow and understanding of the changes resulting from the injection. The resulting risk assessment was used to determine the optimal risk mitigation and monitoring program required to assure CO_2 containment.

In seeking to highlight some of the ingredients of successful projects, the Report stresses the importance of collaboration and points to the success of the Regional Partnerships program in this regard. An industrial partner (or partners) with operational experience was also a critical ingredient for many projects. Successful community outreach was also an essential element, although somewhat surprisingly many projects do not seem to adequately document their efforts in this area. The Report quantifies the range of technologies applied, but also points out that there are other less quantifiable criteria, that are at least as important in terms of helping to maximise the chance of success of a small scale injections and of taking it along the decision pathway. These include a suitable, affordable and adequate supply of CO_2, clarity on the decision-making process and key milestones on which decisions will rest; there is agreement on liability issues and the governance structure and lines of responsibility are defined.

2. Introduction

The aim of this Report for the IEA Greenhouse Gas Program is to document the experience of small scale CO_2 injection tests and the lessons learned from those projects to assist countries or organisations wishing to embark on their first CO_2 injection test.

A number of non-commercial, relatively small scale test CO_2 injections, have been carried out over the past decade, ranging from injections of just a few tonnes of CO_2 to 10,000 tonnes or more of CO_2. These have been undertaken in various parts of the world, including the United States, Canada, China, Germany, Japan, France and Australia. The documentation available from these projects is variable in scope and detail and to date there has been no single compilation of the overall experience arising from these projects. There are various reasons for this including: the capacity of projects to provide comprehensive descriptions of all aspects of a project, the lack of funding for full documentation of a project, the loss of key project personnel, the need for people to move on to the next project as quickly as possible and in some circumstances the commercial sensitivity of a project.

Despite this, there are many potential lessons to be learned from these projects if the information can be successfully compiled and therefore there is clearly great merit bringing together as much data as possible. For countries or organisations seeking to develop their own CO_2 injection and storage project, access to such information could serve to accelerate the development of their proposed project and also result in cost savings to the project. Additionally it is important to ensure that best practice is encouraged in all future projects to facilitate risk management and minimise the prospects of health, safety or environmental incidents arising as a result of poor practices being followed.

Whilst a number of large, successful, comprehensively monitored CCS projects would provide the basis for widespread community acceptance of CCS, projects may not happen if there is strong local or national opposition to the technology in the first instance. Indeed if there is no acceptance at the start, then projects are unlikely to get underway. A number of benefits can accrue from small scale projects, most notably the opportunity to inform the local community (Ashworth et al., 2010), and the community at large about CCS and especially storage, through a real world storage example at a relatively modest cost (say $20-100 million) compared to a full scale project (say 2 billion dollars plus). The other benefits can include:

- a low cost on-the-job learning opportunity for technicians, engineers, scientists, managers
- decreased technical uncertainty and risk prior to embarking on a large-scale project
- impetus to regulators to confront some of the regulatory issues when there is a real project (even if small to medium sized)
- ability to test equipment (and boundaries) at a modest scale, in a way that could not be contemplated for a large scale project
- a real-world working relationship for the partners (if being pursued through an industry partnership)
- testing of legal and other agreements in a relatively benign atmosphere where there is not a lot of money at stake
- tangible evidence that CCS is moving ahead, despite the slow pace of progress on large scale projects
- exposure to working with a real community and understanding how to communicate with and listen to the community

- CCS facilities for politicians, bureaucrats and community leaders to visit and understand
- opportunities to encounter (and overcome) real world problems such as maintaining CO_2 injectivity, ensuring there is no formation of CO_2 hydrates, handling contaminants, testing for brittleness in pipes and running compressors under multiphase conditions
- ablility to test monitoring options under operational conditions and assess the practicality of the various techniques as well as develop new techniques.

Some excellent summary reports have been compiled on the results obtained from individual storage projects, including some large scale projects, such as the Weyburn Project (Hitchon, 2012), the smaller Pembina Project (Hitchon, 2009)) and those arising from some of the USDOE Regional Partnerships (Litynski et al., 2013). However more commonly, it is the scientific highlights of projects that have been published rather than the operational or management or technical details. Whilst the scientific results are very valuable and important from a research perspective, it does mean that a great deal of practical information has yet to be made available.

In some cases the manner in which an injection/storage project was developed and the operational details of the project may not be familiar to researchers. One reason for this is that in some instances the project was undertaken at the 'gift' of a largely commercial operation, with the major driver for the operations being commercial considerations rather than research outcomes, but where the company was willing to provide researchers with access to the project. In such circumstances, the researcher will not have access to all the available information or may be unaware of operational details for commercial reasons. Nonetheless, outstanding research storage projects at a range of scales have been undertaken, within a largely commercial environment, for example the In Salah Project in Algeria and the Citronelle EOR Project in the USA. However, inevitably, as the lessons learned have been within that commercial environment, some information has not been made available for commercial-in-confidence reasons.

There are some projects, such as the Frio, Ketzin and Otway projects, which are, or have been 'owned' by a research organisation and where there are no commercial drivers in terms of oil or gas extraction and where there are fewer constraints on the release of information, including operational information. Additionally, projects supported by the USDOE are typically expected to make information publicly available. Finally the authors have themselves all worked on storage projects which has provided a depth of personal knowledge that was drawn on for this Report.

It is hoped that this IEAGHG study will help new players in the CCS space to develop CO_2 injection and storage projects at a scale of up to 10,000 tonnes of CO_2 or more, in a cost effective, time efficient and safe manner, drawing on lessons from past, present and in some cases planned small, scale CO_2 storage projects.

3. Deliverables

Deliverables for this study specified by IEAGHG were:

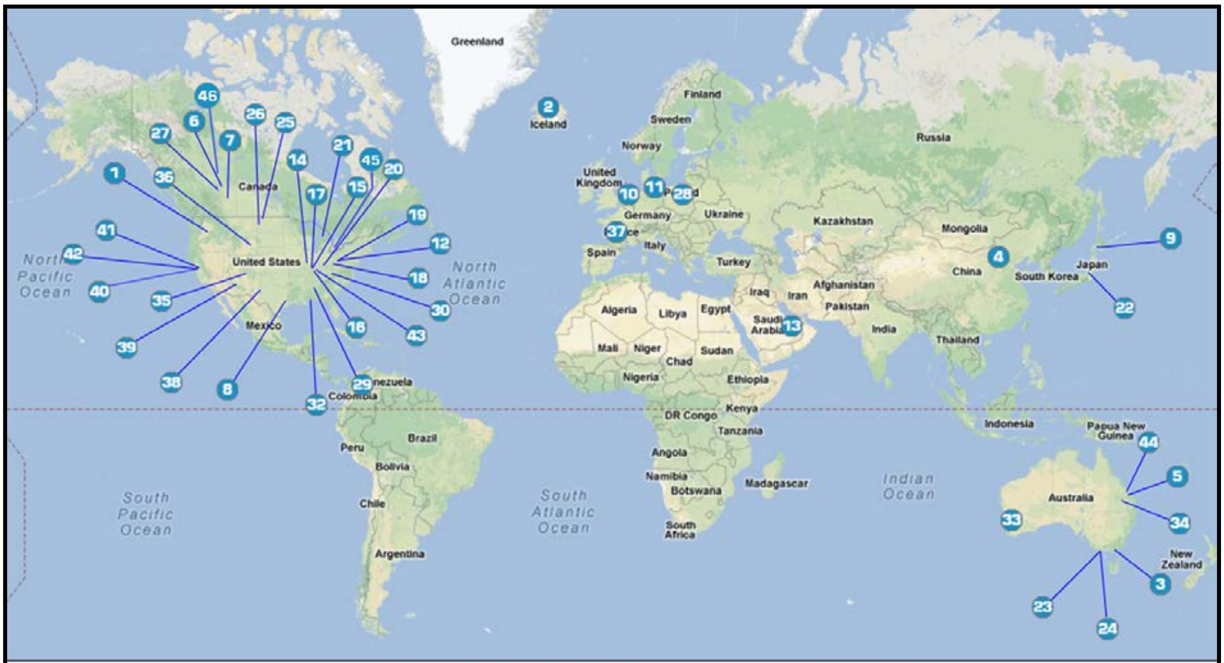
- a compilation of existing test injection projects (completed, operational and planned projects)
- identification of key development issues for projects and how they have evolved over time
- an assessment of trends in project development over time as well as similarities and differences between projects
- documentation of relevant examples of projects, identifying the key factors in a successful project.

4. Compilation of information: A database of small scale projects

Compilation of a comprehensive database of small scale projects was the first and most time consuming task of this IEAGHG review. It was decided to base it primarily, though not exclusively, on publicly available data, and to not include any commercial-in confidence data. As a first step in developing a pro forma for the questionnaire, it was decided by the project team to use the Otway project as a starting point, not because it was necessarily the best documented project, but because the project team was familiar with it and it did provide a comprehensive and publicly available data set. Subsequently views were sought from other researchers on key parameters and in addition the pro forma was modified as additional data were collected from a wide range of projects. Given the scope of the review, as defined by IEAGHG, it was anticipated that by taking a limit of say 100,000 tonnes of CO_2 injected, that this would serve to readily limit the data collected. However, this arbitrary limit proved difficult to 'enforce' on occasions. To illustrate the difficulty that can arise, the Zerogen Project was initiated with the express intent of storing millions of tonnes of CO_2, but ultimately only injected a few tonnes of CO_2. Its final tonnage of injected CO_2 clearly placed it in the 'small scale' category, but much of the methodology adopted by the project and the capital costs were more in keeping with a large 'commercial scale' project than a small scale test. Nonetheless because of the final, quite limited amount of CO_2 injected, and because it had valuable research outcomes, it was decided to include it in the data base. The Cranfield Project (Formally project 31) and the Decatur Project, which are involved in outstanding research, each involved the injection of in excess of one million tonnes of CO_2 and therefore were not included in the small scale compilation.

Nonetheless as part of the data compilation it was decided to collect some information on large scale projects, for comparison purposes and as a way of testing that small scale projects were relevant to large scale/commercial projects. Summary data were collected on a total of 43 large scale projects.

One of the surprises in compiling the information for any scale of project was the great difficulty encountered in obtaining much of the information. There is probably no one reason for this, but it became clear in the compilation phase, that insufficient emphasis was placed by some projects on adequate reporting and particularly on the production of a close out report of the type that has been produced for the Weyburn Project for example (Hitchon, 2012). Given the amount of public money expended on projects, this would seem to be a major failing. Hopefully this Report will help to partly address this gap.



1 BSCSP Basalt	16 MGSC Sugar Creek EOR Phase II	32 SECARB - Mississippi Saline Reservoir Test Phase II
2 Carbfix	17 MGSC Tanquary ECBM Phase II	33 South West Hub (Collie South West Hub)
3 CarbonNet	18 Mountaineer PVF	34 Surat Basin CCS Project (Previously Wandoan)
4 CIDA China	19 MRCSP Appalachian Basin (Burger) Phase II	35 SWP San Juan Basin Phase II
5 CS Energy Callide Oxyfuel Project	20 MRCSP Cincinnati Arch (East Bend) Phase II	36 Teapot Dome, Wyoming
6 CSEMP	21 MRCSP Michigan Basin Phase II	37 Lacq-Rousse
7 Fenn/Big Valley	22 Nagaoka Pilot CO2 Storage Project	38 West Pearl Queen
8 Frio, Texas	23 Otway I (Stage I)	39 WESTCARB Arizona Pilot (Cholla)
9 JCOP Yubari/Ishikari ECBM Project	24 Otway II Project (Stage 2A,B)	40 WESTCARB Northern California CO_2 Reduction Project
10 K12B	25 PCOR Lignite	41 WESTCARB Rosetta-Calpine test 1
11 Ketzin	26 PCOR Williston Basin -Phase II (NW McGregor Field)	42 WESTCARB Rosetta-Calpine test 2
12 Marshall County	27 PennWest Energy EOR Project	43 Western Kentucky
13 Masdar/ADCO Pilot project	28 Recopol	44 Zerogen Project
14 MGSC loudon Field EOR Phase II	29 SECARB - Black Warrior Basin Coal Seam Project	45 East Canton Oil Field
15 MGSC Mumford Hills EOR Phase II	30 SECARB - Central Appalachian Coal Seam Project	46 PCOR Zama Field Validation Project

Figure 1 – Map of small scale project locations.

There are two databases arising from this study: the first consists of a ‘data sheet’ for every small scale project (Table 1). This was compiled in Word for ease of handling. Once compiled for this Report, each project was sent to the project for validation. Most projects took the opportunity to correct any errors, provide additional information or point to potential sources of extra information. A second (corrected) version of the data sheet was then sent out to the project for final validation. A number of (though not all) projects confirmed that the data sheet was correct. The data for every project has been collected and collated uniformly from reports and publications and from project feed-back. The data sheets also provide key references that can be used for further detail. In all, data sheets for a total of 45 projects were compiled (Table 2 and Appendix 2). As two of the projects were added after the analysis of trends, in-depth analysis of various aspects such as monitoring techniques was undertaken on 43 projects.

Table 1 – Data compilation sheet for small scale projects.

PROJECT SUMMARY

Project name:	Total cost of project:
Project owner:	Location:
Project type:	Year of first injection:
Project scale:	Current status:
Type and Depth of reservoir:	Type of seal:

PROJECT DETAILS

	Project operator	Project contact phone
	Project contact	Project contact email
	Project Location	CO_2 Source
	Injection site coordinates	CO_2 transport/delivery
	Project planning start	Injection rate
	Duration of injection	Injection pressure
	Planned injection volume	Total volume injection
	Reservoir porosity	Reservoir permeability
MONITORING	Seismic monitoring	Gravity studies
	Water monitoring	Pressure logging
	Soil Monitoring	Thermal logging
	Atmospheric monitoring	Wireline logging
	Ecological monitoring	Observation well
	Tracer analysis	Geochemical research/Fluid sampling
	Electromagnetic	InSAR
RESERVOIR STUDIES	Reservoir modelling	Geologic model
	Coring	Seismic
	Other technologies	

Project context
Aims of the project
Ownership and liability
Regulatory and approval conditions
Pre-injection geological database and site characterisation
Source of CO_2
Transport of CO_2
Additional Project details
Stakeholder engagement
Significant learnings from the project

Once the data sheets had been compiled (for the 45 small scale projects) a summarised version of the information (Table 2) was put into spreadsheet format (Appendix 1), so that temporal, spatial and other trends could be explored. However if detailed information is required then the reader is referred to the individual data sheets provided in Appendix 2.

Table 2 – Summary parameters compiled for small scale projects (see also Appendix 1).

Project Name	Total Cost of Project
Reference No.	Cost Currency Converted (USD)
Type	Seismic Monitoring
Project Scale	Water Monitoring
Project Owner	Soil Monitoring
Project Operator	Atmospheric Monitoring
Prime Contact	Ecological Monitoring
Phone	Tracer Analysis
Email	Electromagnetic
Project Location	Gravity Studies
Country	Pressure Logging
Coordinates	Thermal Logging
Current Status	Wireline Logging
Project Planning Start	Observation Well
Year of First Injection	Geochemical research/Fluid sampling
Storage Target	InSAR
CO_2 Source	Other Monitoring Technologies
CO_2 Transport/Delivery	Reservoir Model
Total Injection (tonnes)	Coring Model
Planned Injection (tonnes)	Seismic Model
Injection Rate (tonnes per day)	Geologic Model
Injection Pressure (psi)	Reservoir Model
Injection Depth (metres)	Project Webpage

A number of conclusions and observations can be drawn regarding the compilation phase of the study:

- The availability of data on small scale projects is highly variable nationally and internationally.

- There are many examples of project science being well reported, usually in peer reviewed literature, but far fewer examples of the technical, management and operational information being documented. Part of the difficulty for projects is that for the most part, scientific journals are not interested in publishing technical or management or operational details and therefore it is necessary in many instances for the project to itself publish the information and make it available whether in hard copy or electronic copy. The other difficulty that has to be recognised is that the citation index or similar metrics are often the basis of career progression for researchers – reports on operational details seldom result in a high citation index and are therefore accorded a lower priority by researchers.

- A number of the US Regional Partnership Projects offer examples of how data can be effectively compiled and curated, but even in this outstanding national program, the quality of reporting is inevitably somewhat variable. Outside of the Regional Partnerships, projects develop their own reporting and database formats with little uniformity in reporting and few projects appear to have comprehensive, publicly accessible databases.

- Identifying the contact for projects was often difficult, and for older projects, sometimes impossible, due to staff mobility and limited long term curation of information. National repositories for storage information would be valuable.

- The impression was gained that the ease of access to data was very dependent on whether individuals in the project team were still involved or had moved on to other projects or had moved totally out of the CCS arena.

- The Global CCS Institute compiles information each year on commercial projects but there is no such compilation for small scale projects. Given that the data have now been compiled to a uniform standard in this study, to the extent that this is possible, IEAGHG may wish to consider the value of keeping a database of small scale projects updated on an annual basis.

5. Key development issues for small-scale CO_2 injection tests

5.1. The decision pathway

Developing and executing any project, including a small scale injection project, can be expected to follow a pathway not dissimilar to the generalised pathway illustrated in Figure 2 with defined decision points, which may depend upon availability of funds, regulatory approvals, risk assessment, geological suitability and so on. As the project proceeds along the path, the level of investment increases, the level of confidence in the technical aspects increases and the participants in the project become increasingly certain in their involvement. Conversely if these things do not happen and the level of confidence decreases, then either the project embarks upon a new phase of data collection, or additional funds have to be sought etcetera, or the project is abandoned or revised to such an extent that once again the project (and the participants) embark along the decision path. Figure 2 represents a generalised project decision pathway, but this will vary for each project to the extent that there may be somewhat different decision gates or the position and the relative importance of each decision point on the chain may change. For example, some projects may have a fixed budget and a primary and critical point is to live within that budget with no deviation contemplated. Others may be required to inject an agreed amount of CO_2, though with recognition of the need for the budget to have some flexibility to take account of geological or other uncertainties that may affect costs.

A primary aim with all projects, whether small or large, whether commercial or research projects, has to be to decrease uncertainty as the project moves from left to right along the chain. In terms of specific components of the chain, it consists not of a single pathway with a ‘seriatum’ of first funding, then geology, then modelling and so on, but is more likely to be a parallel set of activities, each with their decision points, which in turn feed into a limited number of the higher level decision points represented in Figure 2. The next section (chapter 6) of this Report deals with some of the detailed activities which underpin the decision chain.

Some of the critical issues keep coming back for reconsideration along the chain as part of the ongoing process of review. An obvious example of this for most projects is ongoing consideration of funding, with the question being asked again and again “is the funding sufficient to undertake the project as proposed and if not, how do we modify the project – or the budget?” At the same time, there is an expectation that the degree of confidence in the project costs will increase – and the contingency that is attached to those costs will decrease. In other words the contingency may be 100% of the anticipated capital cost at the conceptual stage of the project, but by the time the final investment decision is made it may be down to 15% of the revised capital cost.

The decision chain in most projects should be structured to allow a “stop”, “go” or “review” decision to be made at agreed points on the critical path, in precisely the same way that a major commercial project proceeds. As pointed out earlier, those decisions will often rely on multiple parameters and a series of ‘sub-decisions’, but nonetheless, there can be critical decisions that may rest on one issue – for example if regulatory approval cannot be obtained, then the project will have to stop until it can be obtained. Therefore the decision pathway can be a complex one, which varies according to the particular circumstances of the project and it is not possible to define a single way forward. Consequently from the perspective of developing a small scale project, the most useful approach is perhaps to define key components which together contribute to the critical pathway.

These are taken here to be issues such as project objectives, project concept, governance, funding, regulation and liability, site characterisation, reservoir modelling and risk assessment, with each of these appearing along the critical pathway at various stages. These are discussed in the next chapter in more detail and examples are provided from projects.

So far this discussion has been about the process that applies to projects in general. The extent to which the process outlined is actually followed by small scale projects is difficult to discern from publicly available information. It is likely that projects with a major commercial partner will follow the conventional decision pathway, but informal discussions with projects revealed that often there is a much less formalised approach. Part of the reason for this may be that where a project is run by an academic institution, such a formalised decision-making process is not a normal part of the research process or the organisational ethos. The other reason may be that there is far less money at stake if a small scale project goes wrong than if a large scale project goes wrong. However this in particular can only be described as a flawed approach, first because whilst the project itself may be low cost, the potential for high cost liability must be considered; and second because an accident at a site, can adversely impact not only on the reputation of those directly involved in the project, but more broadly on CCS as a mitigation option.

How long is the decision pathway likely to be? This varies enormously. It has been attempted in this review to determine the average time, but as is evident from Figure 13 (see later), the time ranges from 1-2 years to 5 years or more. Part of the reason for this variability is differing views on when a project actually starts: whilst the date when injection commences is a clear milestone, when should the project be deemed to start? When it is first (perhaps informally) discussed or when a final investment decision is taken or when it is approved by the regulator? There is no simple answer to this, so for the most part this Report has accepted the starting point as designated by the project, or the earliest date it has found referring to the project. But if an average figure is to be taken then it is of the order of 3-4 years from initiation of a project to first injection. Beyond that, obviously the total time for the project is highly dependent on the scope. A commercial project will continue for as long as there is a requirement to store CO_2. A small scale project will continue until the research or demonstration objective or objectives are achieved, which can be as long as ten years or more if the scope of a project is expanded.

With all this variability in mind and noting the earlier comments about the iterative process that is followed along the project decision pathway, it is perhaps helpful to briefly review each stage before considering in greater detail in Chapter 6 the underlying issues and techniques that contribute to the decisions.

Figure 2 – The generalised project decision pathway.

5.2. Identify and assess

The starting point of every project is different. Typically a project is seen to commence with a desk top compilation of possible project options which will then be narrowed down to the most promising options, but the reality is somewhat different in many cases, with the site being almost preordained because there is CO_2 available, and/or an oil company or a government is willing to make the site available for a test injection, and/or there are research ‘champions’ who want to work in a particular area that they are confident is going to be suitable etcetera. In such cases, the challenge may be to make the site ‘work’ rather than the challenge of identifying the site. So, seldom does a project start with a totally blank sheet of paper; there are usually constraints and preferences, including consideration of socio-economic issues, right from the start. Nonetheless as the assessment proceeds, firmer views start to develop on what are likely to be the more promising sites (and/or the more promising agenda for a site or sites) and the practicality of the sites. How long will this phase take? Again this is highly dependent on the starting point. If, for example, the project is starting off with a ‘blank sheet of paper’ and it is first necessary to undertake a national or regional or basin assessment of all potential storage sites, then this early phase could take a year of more, depending on the size of the area to be assessed and access to existing data. If the area to be assessed has undergone extensive petroleum exploration, then there is likely to be a lot of existing data. If on the other hand it is necessary to do green field exploration, then this phase alone could take several years. So in summary, Phase 1, the ‘identify and assess” phase, could take anywhere from a few months to several years; it all depends on the starting point.

5.3. Select concept

Assuming that Phase 1 has identified a number of options for an injection site, the aim of the second phase is to narrow down the choice of site to one (perhaps with one or more back-up options). In addition, Phase 2 aims to generate several test/engineering concepts and to select these against a pre-agreed set of value drivers. An integral part of this process is to develop a higher level of confidence in a range of critical issues e.g. geology, logistics, the cost. This in turn requires a far greater level of knowledge, which often means that new information needs to be collected and interpreted. It is also the stage at which the regulator is approached to obtain a view on the likelihood of approval. It might also be the phase that reveals that there are actually no regulations to cover CO_2 injection, which results in an additional uncertainty and perhaps also extends the time spent on this phase of the decision pathway, because it is necessary to wait until regulations have been promulgated. Alternatively it may be necessary to assist the regulator to develop appropriate regulations, which probably also requires that key performance indicators (KPIs) are agreed with by the regulator. These are likely to rest on questions such as:

- What is the confidence that the capacity of the reservoir will be adequate for the amount of CO_2 proposed to be injected?
- Under what flow and pressure conditions will the proposed seal retain CO_2 and with what confidence including the possibility of fault reactivation?
- If there is any leakage, will it be possible to detect it (and remediate it)?
- What is the chance of contaminating an aquifer, what would be the environmental significance, how is this “significance to be determined such at risks can be kept ALARP?
- Is there any prospect of leakage to the atmosphere posing a hazard?

During this phase of development of the project it is necessary to also start to talk about the project to stakeholders and especially the local community and to explain its possible scope

This phase also requires that the process of more detailed site characterisation is commenced and that work is undertaken on the design for the plant, and the potential transport system (tanker or pipeline), which in turn has major implications for the plant and the site layout. By this stage, a significant level of funding is required and therefore it is necessary that the foundation members (or the company) have agreed to provide that funding and to take the project to the front end engineering design (FEED) stage.

Phase 2 is a very important in that it sets the scene for the entire project and requires a great deal of expert staff time and adequate funding in order to proceed to the stage of final investment decision (FID). Again, if the project is being undertaken at a site where there is already a great deal of information as a result of petroleum exploration, where there is exploration activity underway and where regulations are already in place, then Phase 2 can possibly be accomplished in as little as 12 months. More realistically it is likely to take up to two years or more depending on the availability of data and staff.

5.4. Define

The aim of this phase is to further reduce uncertainty in all the areas considered in the previous phase, but also, and perhaps in particular, to define and finalise the project scope and undertake detailed engineering design with the aim of taking the Project to final investment decision (FID). Final decisions are reached in this phase on the source of CO_2 because of the implications this is likely to have to engineering design. This could include any issues arising from the presence of impurities in the CO_2 stream (for example is any water going to have to be removed or alternatively is stainless steel to be used), any need for onsite storage of CO_2 and detailed planning for any health, safety or environmental issues. The budgetary implications of the detailed engineering design require careful consideration and by this stage the aim is to bring down the level of uncertainty and decrease the percentage required in the budget for contingency.

By this stage initial reservoir modelling (static and dynamic) will have been completed, thereby enabling an assessment of the likelihood of various extents of the CO_2 plume, including demonstration that it would be highly unlikely to extend beyond any boundary specified by the regulator or beyond areas where there are agreements in place with landholders. In some projects, where the aim is to look at some particular aspect in detail, such as residual trapping, more detailed design will be needed on the experiment to decrease any experimental uncertainties.

Depending on funding and the level of confidence of the project participants, some baseline surveys may be undertaken during this phase, not because they are necessary for FID, but because the sooner they are commenced before any injection, the greater the degree of confidence that natural variability can be clearly differentiated from any changes resulting from the project. It may also contribute to the granting of final approvals for the project from regulatory authorities.

The ‘define’ phase concludes with a final investment decision by the company, the consortia or the Board, depending on the governance arrangements, in light of the budget being realistic (and the funding available or very likely to be available), an effective risk management strategy, all agreements with landholders in place, the necessary government /regulatory approval finalised and agreements in place regarding liability issues as well as appropriate insurance cover and a reasonable expectation that the project will be able to earn and retain the social licence to operate.

The amount of time this phase is likely to take will vary greatly with the complexity of the project. Where an existing operator (probably an oil company) has responsibility for the project, this phase may be achievable in a matter of months. Where the project is 'owned' by a non-operating entity, such as a government body or a research organisation, it is likely to take a minimum of one year. If insufficient funding is available initially, then seeking the required additional funds can further slow down matters.

5.5. Execute

Having now got the final investment decision in place, the project enters the 'execute' phase, where the project is constructed and commissioned. This is obviously the most expensive phase of the project with equipment and pipelines installed, wells drilled and roads and tracks constructed. Therefore it is essential to have the necessary systems in place for approvals and cost control. It is likely that this stage will take at least 12 months in the case of a greenfield site. If one or more wells have to be drilled then obviously the time taken can increase considerably (along with costs) if down-hole problems are encountered. If on the other hand, the project is being carried out by the owner-operator, then the process is much simplified and is likely to be much quicker.

Along with the construction and related commissioning, it is likely that during this phase, the monitoring program will be refined and baseline monitoring initiated or continued if it is already initiated, any final approvals obtained, the risk assessment further refined and emergency response plans developed and perhaps tested. A comprehensive operational plan will also be developed during this time. Community consultation will also continue, possibly including site visits for interested members of the local community.

The concluding act of this phase is likely to be the decision to commence injection of CO_2. This may be a phased process in that there may be a small scale injection to ensure all systems are working as expected, before a major phase of injection is initiated. This commencement is also likely to fall under the close scrutiny of the company or the consortium or the Board, as it marks a significant (increased) phase in the risk profile, with the related potential liability implications. Consequently, there is (and should be), a formalised and fully documented approval process to commence injection.

5.6. Operate

Provided the previous phases of the decision pathway have been undertaken carefully and all approvals obtained, the operational phase should in theory proceed smoothly. The reality is that there are likely to be many unexpected complications. Hopefully these will be of a minor nature and will not adversely impact on the project to any significant extent. Again, full documentation of all incidents is the expectation for this phase.

The time for the operational phase to run will have been determined on the basis of the injection rate and the amount of CO_2 to be injected. If on the other hand the operational time is based on meeting a particular key performance indicator, such as detection of injected CO_2 at a monitoring well, then the duration of the operational phase may be less certain. If the KPI is not achieved, then the operations may be terminated when the budget limit is reached. Conversely if the KPI is reached before the anticipated date, then there may be funds available for doing some additional research. Therefore depending on the motivation for the project, there may be benefits in building flexibility into the operations to enable additional research to be done. It may also be that depending on the results a whole new phase of the project may be proposed, that builds on the infrastructure and the knowledge built up in the project. This is likely to be a very cost effective way of obtaining new information rather than necessarily undertaking a new project at an entirely new site.

From the broader CCS perspective it is very important that wherever possible, the opportunity is taken to arrange site visits for key stakeholders whilst operations are in progress and therefore this should be regarded as a core component of this stage rather than just an 'add-on'. Obviously monitoring is one of the most important aspects of this phase of the project, with the possibility that if something unexpected were to happen, such as a major leak into an aquifer or into the atmosphere, then the project may have to be interrupted whilst remedial work was undertaken or it may have to be prematurely terminated. The chance of this happening at a well characterised site, with leading practice operations and monitoring is remote, but nonetheless there must be contingency plans in place.

Finally during the operational phase it is necessary to start to draw up plans for well abandonment. Initially this needs only to be a very generalised plan, with a very approximate budget, but as the operations proceed towards completion, those abandonment plans must become progressively more detailed.

5.7. Abandon

It will be important to distinguish between suspension, closure and abandonment, though all three of these stages are included here in this final phase.

A decision to suspend injection may occur during the operational phase because of some temporary difficulty arising and it could be of quite short duration. It is unlikely to require any formal approval process and will just be regarded as an operational issue. Where a project has been completed, the decision may be taken to suspend injection while a new project proposal is developed for the site. This may have been built into the original project proposal as a logical way forward, or it may have evolved as the project progressed. In either case it is likely that a formalised approvals process will have been pursued for the suspension to occur, because of the need to plan for a new phase, with the funding implications that this may have. It is likely that the regulator will require that monitoring continues during any extended suspension. Obviously the commencement of a new project at the site defers any decommissioning.

A decision to close the site has much more significant implications for decommissioning in that there are likely to be major costs arising from the need to remediate a site and initiate the formal well closure process required by the regulator. It is likely that some KPIs will have been agreed with the regulator, when commencing the closure process which in turn will require ongoing monitoring. Alternatively the regulator may just require that an agreed program of monitoring continues for a specified period, before closure is permitted.

The final stage of abandonment will, as a minimum, require that the injection well and any monitoring well be plugged and abandoned, unless of course a third party such as a government body decides that the well would be useful for some other purpose, in which case, formal responsibility (and any liabilities) would transfer to that third party. The extent to which monitoring is required after abandonment will be totally dependent on the regulator and the agreements reached at the start of the project. However, the regulator may not require any further monitoring after abandonment has been approved. At this stage, again depending on the agreements with governments at the start of the project, it is possible that there will be a transfer of ownership (and liability) to government or some other body.

It is important to point out that the manner in which this final 'abandon' phase will be carried out and how liability is handled is somewhat speculative, to the extent that to date there is no publicly available information on CO_2 injection sites that have been formally closed, abandoned and handed back to the licensing authority or some other responsible government body, with the possible exception of some of the acid gas injection projects in Western Canada.

6. Trends in project development: similarities and differences between projects

As has been previously pointed out, every injection project is different. In addition there are only a limited number of projects to compare and contrast or for trying to establish trends. Consequently it is possible to only compare projects in a very general way.

6.1. Project distribution

Right at the start of a project, there has to be consideration of locational issues (is the initiative and funding coming from a particular state or province or company which requires that the project is undertaken in a specific geographic area) or to test a particular geological storage option, or are there logistic issues. Whilst not explicit in the data sheets, it is clear that there are a range of fairly pragmatic reasons for the general location of a project, but obviously the geology has to be potentially suitable and this is discussed in greater detail under ‘site characterisation’ (Chapter 7). The distribution of small scale projects (Figure 1) clearly demonstrates the relative abundance of small scale projects in North America, compared to the rest of the world, probably reflecting two things: the success of the Regional Partnership program in encouraging projects and second, the availability of CO_2 because of the existing CO_2 pipeline system, which in turn reflects the many EOR opportunities and projects, particularly in the United States. The relative lack of small scale projects in Europe may be improved with the two very recently announced UK CCS projects, which are not included in the database as there were few details available on whether they will include small scale projects. However the political problems encountered with storage projects, such as in Germany, is likely to be an inhibiting factor particularly for onshore projects in Western Europe. The fact that some countries or regions have banned onshore storage is also a major inhibition to undertaking small scale projects, given the very much higher cost of undertaking any project – large or small – that would be incurred for an offshore project. The comparative abundance of small scale injection projects in Australia is in part a reflection of the fact that two distinct projects have been undertaken at the one site (Otway) and the prospect (which may or may not be realised in every case) that the three Flagship projects will include small scale injections. The Gorgon Project and the related Barrow Island storage project may have undertaken a small scale injection tests as part of the lead up to the initiation of the major storage project in 2016, for a data well was drilled, but the injection test may have been done with water rather than with CO_2.

6.2. Project purpose

Does the purpose for which a project was undertaken provide a basis for categorising of projects in order to look for trends? A clear statement of project objectives was sometimes difficult to find in project synopses. The majority of small projects were described by the proponents as ‘trial’ or ‘test’ projects (Figure 3). Some will never be anything other than excellent small scale projects, for example Ketzin or Carbfix. A number were, are, or will be, tests that precede larger scale projects. For example the Carbonnet Project which is still at the planning stage, envisages that a small scale test will be undertaken as an early step. Several of the Regional Partnerships have small scale tests preceding anticipated (Stage 3) larger tests. However some, for example Zerogen, were initiated with the intention of it being a large scale project, but ended as a small scale test. In other words, project objectives changed, or were not always attained, or the perfectly realistic decision was taken in the case of a commercial project, that the project was commercially non-viable. About one-third of projects were classified as 'research' although the specific purpose of the research was not always spelt out, but it is likely that many were largely to demonstrate safe injection and storage, with monitoring a key component of this. Overall there is no indication from the database that the purpose of projects has changed over time. However, it is apparent that where project sites extend beyond their initial purpose of demonstrating storage, they do evolve to answer specific questions, such as whether a particular monitoring technique can be applied or developed (as in the case of the Ketzin Project) or to determine residual CO_2 trapping (as in the case of the Otway II Project), suggesting that there is extra scientific value to be obtained from sites where the opportunity exists to explore specific scientific issues.

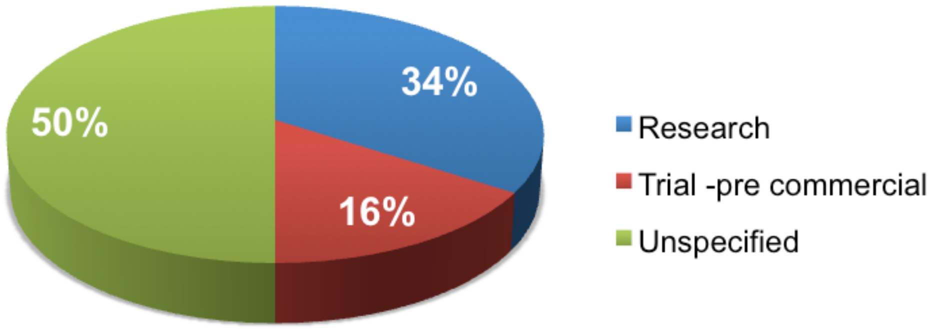


Figure 3 – Small scale projects differentiated by the type of purpose each project falls under.

6.3. Ownership and governance

Small scale projects show a range of ownership and governance models. State (or provincial) government agencies are the owner or co-owner as part of a research alliance of the majority of pilot injection sites (Figure 4). Energy companies and research organisations own 11 and 8 pilot operations, respectively. While purely government-owned projects focus on injection into deep saline aquifers, energy companies and research organisation cover the full range of CO_2 storage types (Figure 5). However the distinction between 'research organisation' and 'research alliance' is not always clear. For example, CO2CRC is funded as a research alliance, but also is a company with the status of a research organisation. It is apparent that research alliances are the single most important 'owners' of pilot projects, but what is not so clear from the data compiled is the precise form of ownership. In many, indeed most cases, the alliance may not own the storage site and their status is more that of an overall manager of the total project, though not necessarily of the actual operations, which are often outsourced to an experienced service or drilling company, who in turn may subcontract specialised aspects of the operations to another service company. Therefore the picture of ownership, management and operation for projects can be quite complex and is seldom described in any detail by most projects.

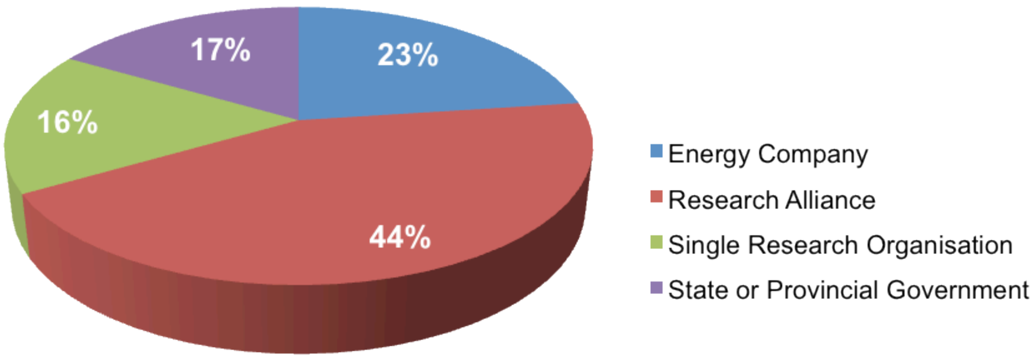


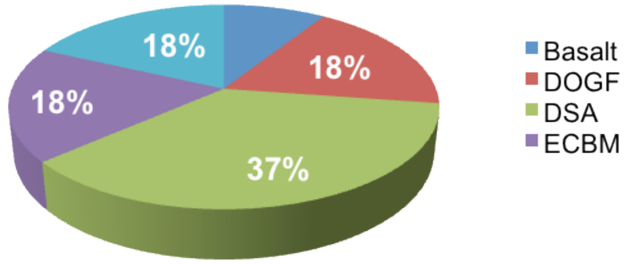
Figure 4 – Ownership of CO_2 pilot injection projects.

Few of the small scale projects provide any information on governance arrangements. If the Project is being undertaken and funded solely by one organisation, then clearly the decision on what arrangements to put in place rests with that organisation and the regulator. The Lacq-Rousse project appears to be an example of this approach. However, this review of small scale projects revealed that most projects involve collaborative arrangements between several organisations and can involve up to twenty or more organisations – industry, governments, research bodies, academia. In some instances, a single organisation will be the operator or the lead partner for the other partners, with the operator also the incorporated entity with legal responsibility for the project. The Nagaoka Project appears to be of this type. This can be a relatively simple arrangement to put in place provided the partners are agreed on all aspects of the project and have a clear mechanism for handling disputes should they arise. In some instances, where the project is part of an oil or gas project, the operator has the tenement, knows the geology, may provide the CO_2 and is willing to take on legal liability. The operator may also insist on ‘owning’ the project so that risk can be satisfactorily managed, whilst the other participants may contribute cash, staff time, expertise etc to an agreed formula. An example of such an arrangement may be the San Juan Basin small scale project.

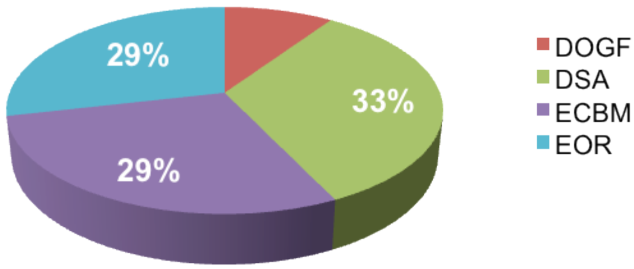
A few projects appear to be “owned” by an academic or research institution, such as the Frio Brine project (Texas Bureau of Economic geology) or the Ketzin Project (GFZ), but seldom do the organisations own the tenement. Some projects are owned by governments; for example the Carbonnet Project (Victorian Government) and the South West Hub project (Western Australian Government).

One of the less common arrangements is that used for the Otway project, in which a group of companies, governments and research bodies have set up a special purpose vehicle, an incorporated legal entity – specifically a Company Limited by Guarantee - CO2CRC Limited. This company holds the tenements and other assets, is the formal operator (although day-to-day operations are subcontracted out) employs people, handles liability and is required to formally report to the regulator. The partners have each agreed to contribute cash and in kind to the Project and to share liability. The Chief Executive reports to the Board of Directors.

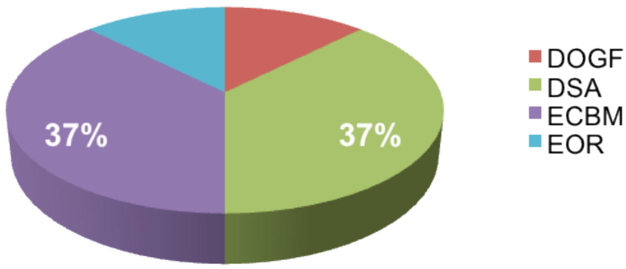
Injection projects for energy companies



Injection projects for research alliances



Injection projects for single research organisations



Injection projects for state or provincial government

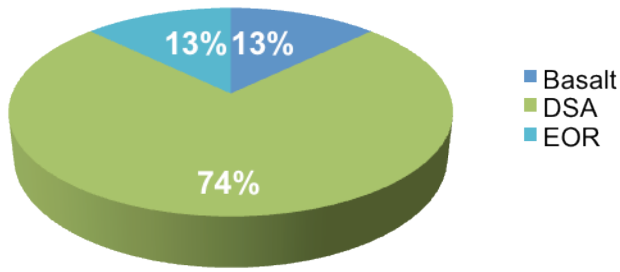


Figure 5 – Type and number of pilot injection operations four different ownerships. DOGF = depleted oil or gas reservoir, DSA = deep saline aquifer, ECBM = enhanced coal bed methane operation and EOR = enhanced oil recovery project.

There is no preferred structure for small scale projects in that each project has to operate within unique circumstances, that vary with who holds the tenements, who is willing to take on liability, how the costs are met etc. What is important to do at an early stage, is to have a clear governance structure and decision-making process, so that all risks to the project can be effectively managed.

6.4. Funding

Few of the projects give any indication of their funding arrangements. It is possible, with some difficulty, to determine how much a project is believed to have cost and this has been done in this review (see Appendix 1). However it is always difficult to compare project costs. Costings are often done on a different basis, with some projects including in-kind contributions and others not. Some fully cost staff time whereas others use different staff-time formulae. Some have to purchase CO_2 whereas others get it at no cost to the project. It becomes even more difficult to compare costs between countries. In addition there are few small scale projects where a comprehensive post project financial analysis has been undertaken. One of the few examples where it has been done is the Zerogen project, which is perhaps a reflection of the fact that it was primarily a commercial project which only became a small scale project by default. In commercial projects, the approach is often taken that there can be no start on a project until all the money is confirmed. Some of the small scale projects may also work this way, but in a research environment, which is what most of the small scale projects are, there are often funding uncertainties throughout much of the first half of the decision chain.

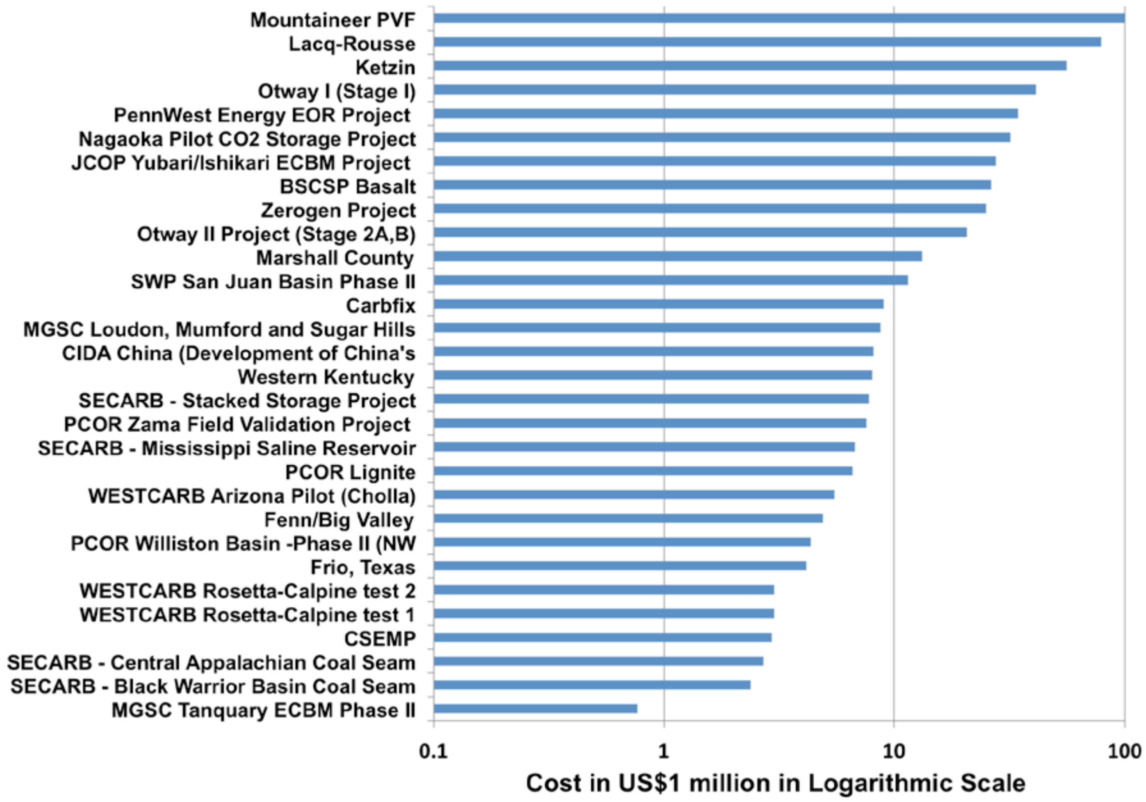


Figure 6 – Indicative cost of small scale projects in US$ (2013). Note the use of a log scale.

This arises in part because the project is often first-of-a-kind, where there is no early basis for budgeting. Therefore, initially the budget is little more than an aspirational budget, within which the project concept is developed – and vice versa.

The comparative cost of Projects is shown in Figure 6. The cost varies from as little as approximately $1 million for the MGSC Tanquary project to approximately $100 million for the Mountaineer PVF project and $80 million for the Lacq-Rousse Project. At the other end of the scale, several of the ECBM projects appear to be exceptionally low cost, probably because virtually all the costs were met by the gas company. If these values are excluded, then the range of costs for small scale projects is of the order of $4-40 million, with a mean value of approximately $15-20 million.

6.5. Reservoir Lithology

Some projects have been undertaken to demonstrate the potential for storage in particular lithologies (Figure 7), with storage in sandstones being the dominant storage option (50%) and 17% in carbonates. Storage in coals makes up almost a third of all small scale tests. Basalt storage was the least investigated of the lithologies, with only two basalt projects - BSCSP Basalt and Carbfix. The Carbfix project specifically identifies research into mineral carbonation as an objective, whereas in the case of the BSCSP project, the research focus is on monitoring and leakage. How does this compare with large scale projects? 75% of large scale projects are in sandstone reservoirs, 17% in carbonates and 8% in coals. Not surprisingly perhaps, there are no large scale projects in basalt. In other words the small scale projects do reflect fairly well the reservoir preference in large scale projects and probably also the general perception of the storage potential of these lithological types. The only disparity is in coals which appear to attract a high level of research interest, despite the lack of interest in coal at the large scale, perhaps because the results from small scale coal projects provide evidence that storage in coal is unlikely to be commercially viable or provide significant storage capacity.

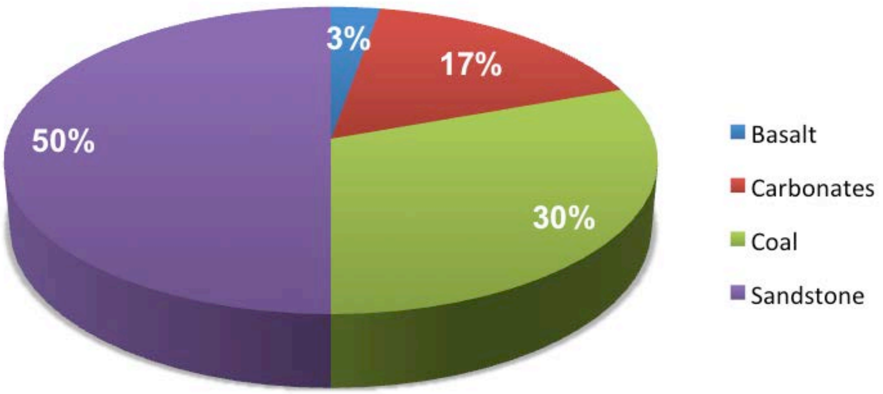


Figure 7 – Range of sediment type into which the CO_2 is injected in small scale projects.

6.6. Storage type

When projects are considered according to storage type (EOR, depleted oil and gas, deep saline aquifers, ECBM, basalt), deep saline aquifers (DSA) are the single most important storage option tested (Figure 8), followed by approximately a quarter of all tests related to coal bed methane production (ECBM) and rather fewer related to enhanced oil recovery (EOR). Some projects have tested (or will test) more than one storage type, for example Otway I undertook research into storage in a depleted gas field, whereas Otway II, at the same site, is undertaking research into a saline aquifer which lies above the reservoir tested in Stage 1. How does the profile of large scale projects compare with small projects? DSAs are again the single most important large scale reservoir tested, with approximately 50% of all projects, but EOR at 34% is obviously and not unexpectedly, far more common in large scale project than in small scale injections. In fact the boundary between what is a DSA and what is EOR in some projects is somewhat uncertain in that some injections may be undertaken into reservoirs that have residual oil in some places and not in other, or the injection maybe initiated in the water leg of a depleted structure; a number may fall into both categories. However ECBM at 8% is clearly far less common at large scale than in small scale injections.

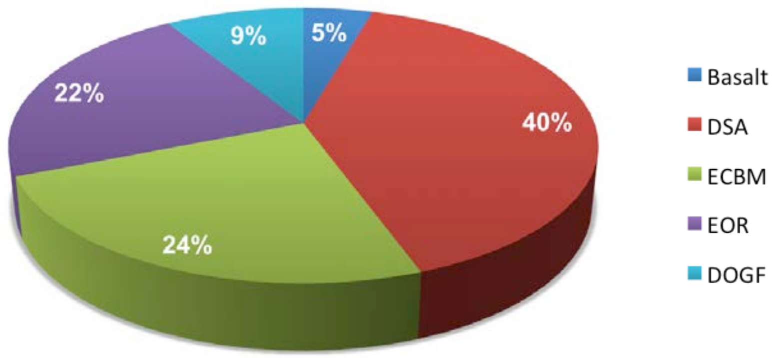


Figure 8 – Type of small scale projects; DOGF = depleted oil or gas reservoir, DSA = deep saline aquifer, ECBM = enhanced coal bed methane operation and EOR = enhanced oil recovery project.

6.7. Source and transport of CO_2

One of the most vital issues for any project, large or small, is whether a source of CO_2 can be secured for the proposed project. Figure 9 shows that approximately 40% of projects have a geological source of CO_2 (especially in the USA, where there is an extensive CO_2 pipeline network) with approximately 30% from gas processing (a secondary form of geological CO_2). However approximately 20% of projects use food grade CO_2 (usually at a cost of up to ten times that of geological CO_2). Only 5% of projects use combustion-sourced CO_2. In terms of the long term aim of CCS to make deep cuts in emissions from coal-fired power plants, there would be merit in having far more small scale projects using combustion-based $CO_{2.}$ However, given the major cost of capturing the CO_2 from flue gases, and the uncertainty surrounding the availability of this source for some years to come, most projects decide on the lower risk and cheaper CO_2 that is available from geological or natural gas sources. This is likely to continue to be the case for some time. Notable exceptions include the Mountaineer PVF Project which used CO_2 separated from a slipstream of flue gas from a coal-fired power plant to inject 37,000 tonnes into two reservoirs. The Lacq-Rousse Project is another excellent example of a whole CCS chain using CO_2 sourced from an oxyfuel plant, injecting about 50,000 tonnes of CO_2. The Ketzin Project which has injected a small amount of 1500 tonnes of CO_2 from the Schwarze Pumpe oxyfuel pilot plant operation in eastern Germany within the frame of a field test. This demonstrated ‘proof of concept’ but proved impossible to do on an ongoing basis for largely political reasons, though cost may have been another factor.

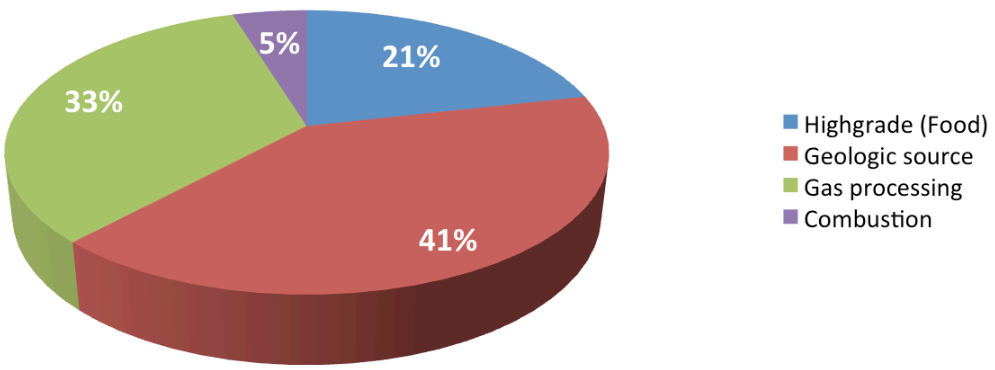


Figure 9 – Type of CO_2 source for small scale projects.

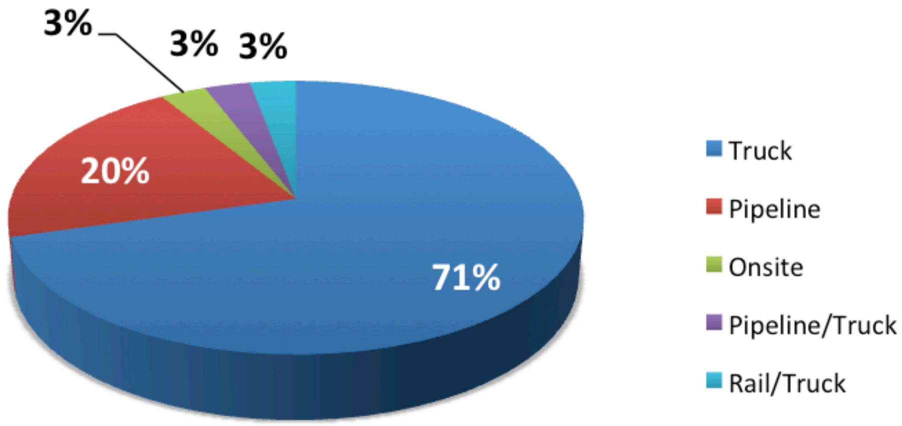


Figure 10 – Method of transport of CO_2 for small scale projects.

The type of CO_2 that will be used also influences how the CO_2 will be transported to the project site. The dominant mode of transport of CO_2 for small scale projects (Figure 10) is by road (truck), which also has significant cost implication, but obviously in general it is much cheaper to use road transport for small quantities of CO_2 than to install a pipeline for small quantities. An exception to this is the Otway Project which built a short pipeline from its dedicated source of (geological) CO_2 with approximately 20% methane, when it became clear that a pipeline was the cheapest option. In the USA, it is sometimes only the final relatively short distance from a pipeline to the project site that is by road. So far no project is based on ship transport.

Clearly then, sourcing the CO_2 is a critical component of the project concept, which can have profound financial, locational and logistic implications to the project. In addition, once the source of the CO_2 is confirmed, it is seldom possible to make changes, without incurring significant extra costs and delays. Therefore the decision on CO_2 source and transport is a very important part of the decision chain and largely reflects the financial reality that it is more cost effective to transport a few thousand tonnes of CO_2 by truck.

6.8. Amount of CO_2 injected

Does the amount of CO_2 injected, provide a basis for defining trends? The amount of CO_2 that is to be injected and stored is regarded as a specific objective in some projects though it should not be seen as something that necessarily has to be attained, for the project to be a success. For example, if a project proposes to inject 10,000 tonnes of CO_2 and only injects 8000 tonnes, this does not mean that the project is unsuccessful, if the scientific objective was met by injecting only 8000 tonnes. Nonetheless the amount of CO_2 to be injected is often seen as an important metric. In terms of community perceptions it may be difficult to convince a non-specialist that injecting a few hundred tonnes of CO_2 can be used to demonstrate the safety of injecting millions of tonnes of CO_2. Realistically, a project that injects just a few tonnes of CO_2, may provide the basis for answering some important scientific question, but will not have the public, or political impact, of injecting a commercially significant quantity, such as 20,000 or 50,000 tonnes of CO_2. The database suggests that the amount of CO_2 injected, provides little other than a fairly arbitrary basis for categorizing projects, in that there is a continuum (Figure 11). However, approximately half of all small scale projects involve injection of 1000 tonnes or less of CO_2, one-quarter are in the range of 1000-10,000 tonnes and one-quarter are in the 'commercially-significant' range 10,000 to 100,000 tonnes. This suggests on balance there is no particular lack of balance in scale, although it might be expected that the initial need for an injection in a region or country where one has previously not been undertaken, will be to carry it out at a 'commercially (or politically?) significant' scale, which may lie in the range of 10,000-50,000 tonnes of

CO_2. Subsequently, the need may well be to answer specific engineering or scientific questions, where an injection of less than 10,000 tonnes of CO_2 will suffice, perhaps before embarking on a large scale or commercial scale project of say one million tonnes. Therefore there is nothing to support the view that the natural progression with projects will be to inject progressively more CO_2; well formulated questions that are effectively answered by well conducted experiments with modest amounts of CO_2 injected may allow a large scale project to progress more speedily, rather than having a seriatum approach of multiple injections with each injecting progressively more CO_2 than the last. A more sophisticated approach to the issue may ultimately be more cost effective and time effective.

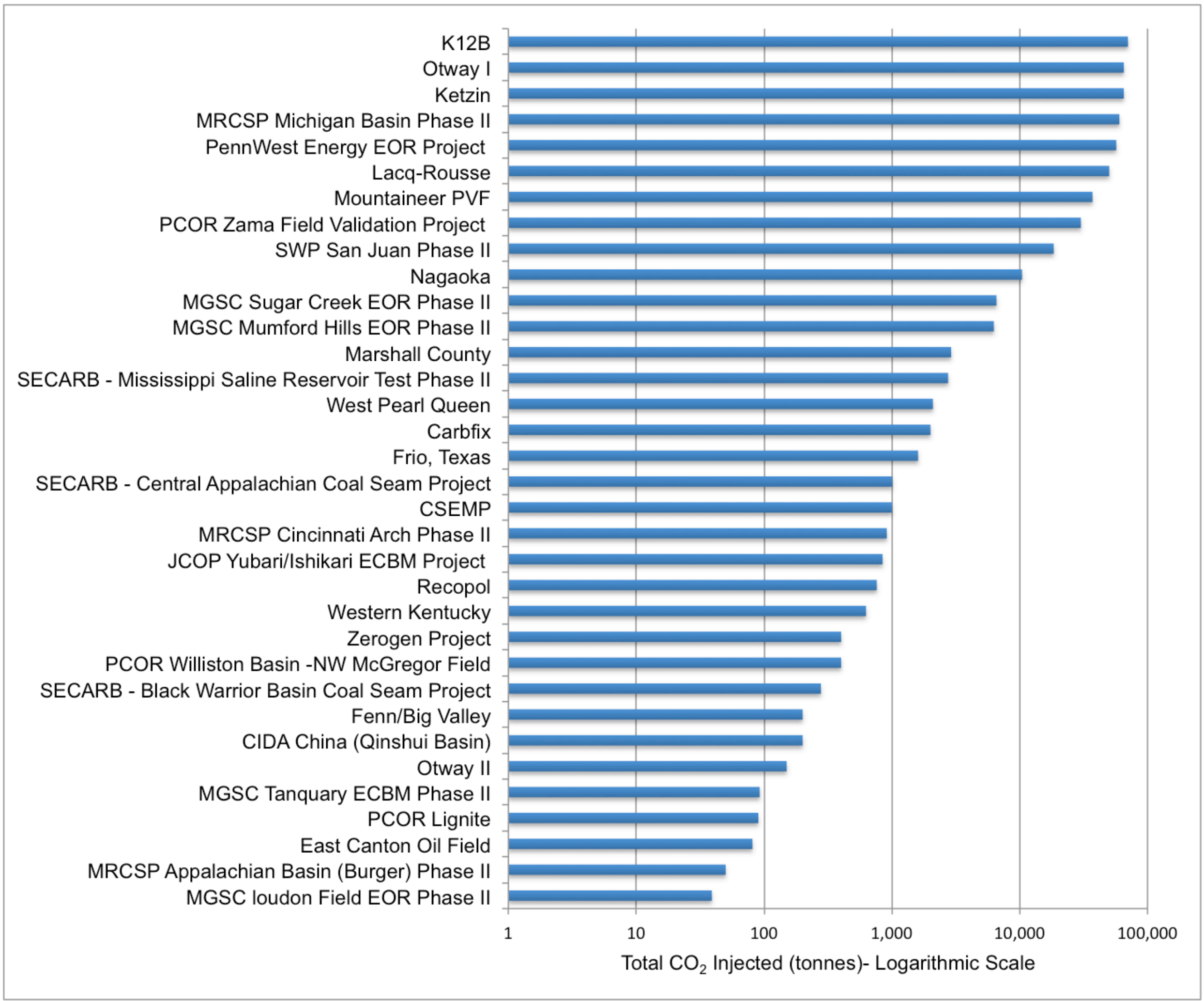


Figure 11 – Total known CO_2 injected in small scale projects (on a logarithmic scale).

6.9. Depth of injection

Another metric obtained through this review was the depth of injection Figure 12. There is no inherent reason why a 'shallow' injection is better than a 'deep' injection, and the deeper the injection the more costly it is likely to be Whilst it would be better to state an operating pressure rather than focus on depth, pressure information is seldom provided for projects where as depth is generally given. One reason for determining the depth of injection may be the presence of competing resources. Some injections are as shallow as approximately 335m (e.g. PCOR lignite) and the deepest is over 4000m deep (the Lacq-Rousse project). Clearly very different questions are being explored in the shallow projects where the CO_2 is sub critical. In fact almost half of all small scale projects have had injection depths of 800m or less, most of these in coal basins where obviously a major driver was to investigate ECBM and where the optimum enhancement in methane production is when the injected CO_2 is subcritical. Therefore this does provide a fairly clear distinction in Project type i.e. whether or not the injection is at depths greater than or less than 800m. Once the threshold of approximately 800m is crossed, then the project will be less costly if the CO_2 is injected at say 1500m rather than 3000m, but the deciding factor on depth is likely to be the suitability of the geology and the objective of the project.

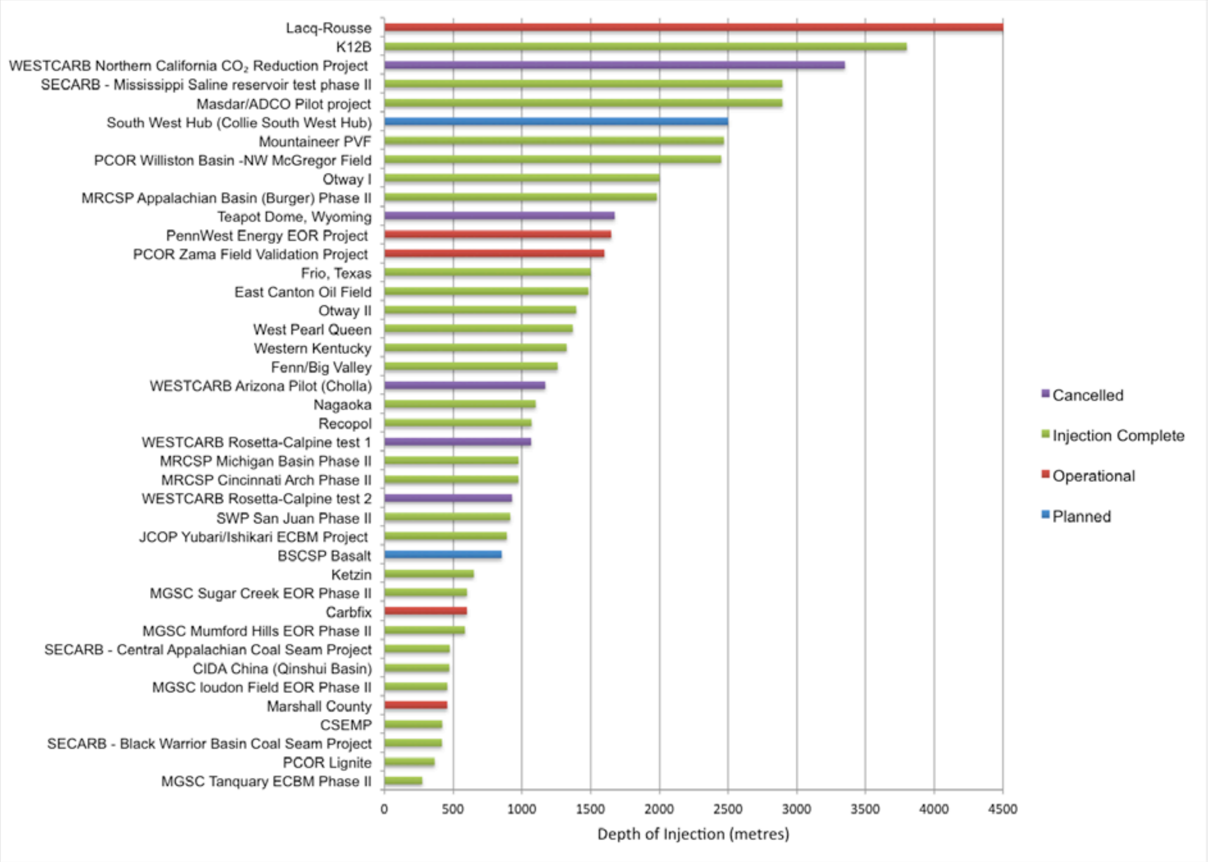


Figure 12 – Known injection depths for small scale projects, (values for projects that provided ranges of depths were averaged).

6.10.Project lead time

Does the time to undertake a project show any trends over time? In other words over the past decade or so has it been possible to more speedily undertake a project because of prior experience? Figure 13 shows the lead time from when a project was first proposed to when the first injection of CO_2 took place; there is no obvious trend, with the 'lead time' ranging from as little as one year to six years. Part of the difficulty here is that the point in time when a project is considered to have started is very unclear in most projects. Was it when the idea was first conceived, or when the money was obtained for the project, or when it was approved by the regulator? Few projects provide a detailed timetable/gantt chart to indicate their progression. Therefore it is not possible to discern a 'learning curve' over time. More likely the time taken to initiate injection is related to whether or not it is conducted on a brownfield site such as an existing petroleum tenement (and be part of an active EOR project for example) where the geology, the injectivity and the reservoir model is well known, compared to a greenfield site. Obviously issues such as the time taken to conclude stakeholder agreements and finalize funding also have a major impact on timing, which obviously varies from project to project.

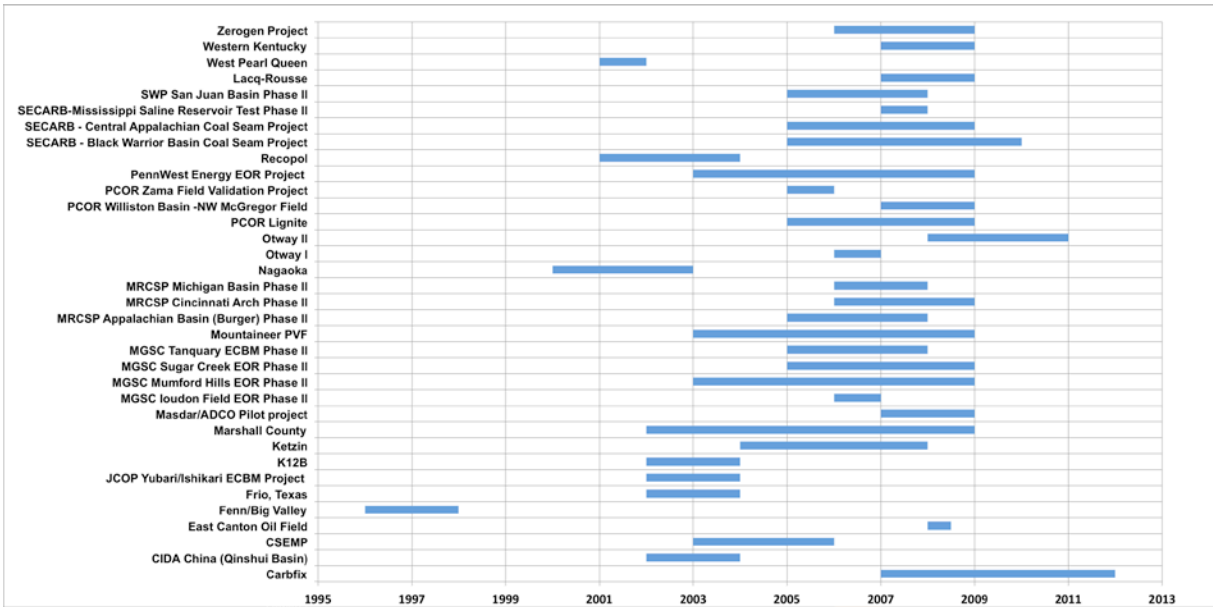


Figure 13 – Project lead times for projects with known year of planning start as well as year of first injection.

7. Relevant examples of small scale projects

The previous chapter has documented a number of features of small scale projects and as previously pointed out, there is great diversity in the range of projects. In addition there is no single project or group of projects which could be regarded as 'ideal 'projects and could be used as prototypes of the perfect project. What can be more usefully done is to provide examples of projects where particular technologies or approaches have been successfully applied, focussing on the critically important areas of site characterisation, reservoir modelling, monitoring and risk management.

7.1. Site characterisation of small scale injection sites

A preliminary evaluation of the projects compiled for this study suggested that the high level of geoscientific investigation required to prove up a suitable injection site, was often underestimated. This in turn often appeared to lead to a lack of appreciation of the significant resources that need to be devoted to proving up a storage site. This is perhaps particularly the case for experts in other parts of the CCS chain such as power station engineers, chemical engineers, government regulators, finance providers who may have no direct experience in exploration for resources. Therefore, as part of this study, an assessment of the amount of effort devoted to the characterisation of an injection site prior to the start of the injection operation was considered to be important (Figure 14).

The CO2CRC defines site characterisation in the context of geological storage of carbon dioxide as "the collection, analysis, and interpretation of subsurface, surface and atmospheric data (geoscientific, spatial, engineering, social, economic, environmental) and the application of the knowledge to judge, with a degree of confidence, if an identified site will geologically store a specific quantity of CO_2 for a defined period and meet all required health, safety, environmental, and regulatory standards" (Cook 2006).

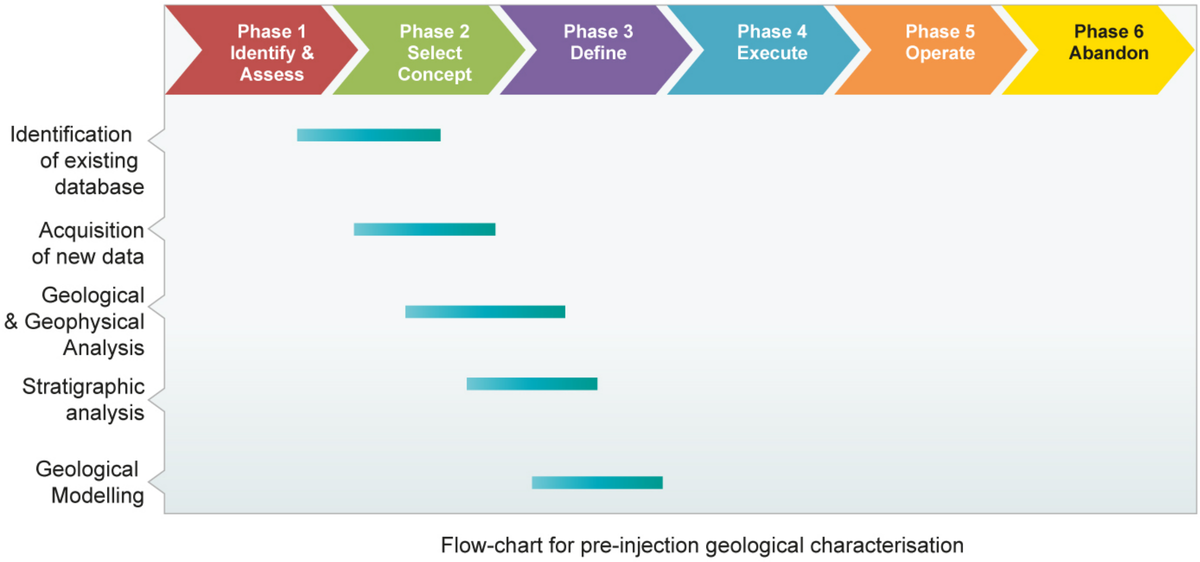


Figure 14 – Pre-injection flow chart diagram.

The development of safe storage at a commercial scale site requires a detailed site investigation, with all the associated exploration costs, before financial commitment can be made to a major project. The few major non-EOR projects in operation today (such as Sleipner and Snohvit) or under construction (Gorgon) are not typical of future power generation CCS projects in that these existing projects are intimately related to gas extraction projects and have therefore leveraged very extensively on the databases built up in the exploration and development of these resource projects.

Schematic work flows for a detailed geological characterisation project have been offered in a number of publications, e.g Gibson Poole et al. (2005) and Gibson-Poole (2008). However, these are often developed on the basis that the process starts with the search for a greenfield site and finishes with the decision point of moving to a commercial project. Most of the projects in this study do not fit into this pattern as they have been conceived as small scale tests, although some, such as the US Regional Partnerships are designed as precursors to demonstration scale projects. Site selection in many of these cases can often be opportunistic, depending on what can be made available by an industrial partner rather than being the result of a rigorous selection process. A suggested alternative work flow for small scale demonstration projects is given in Figure 15.

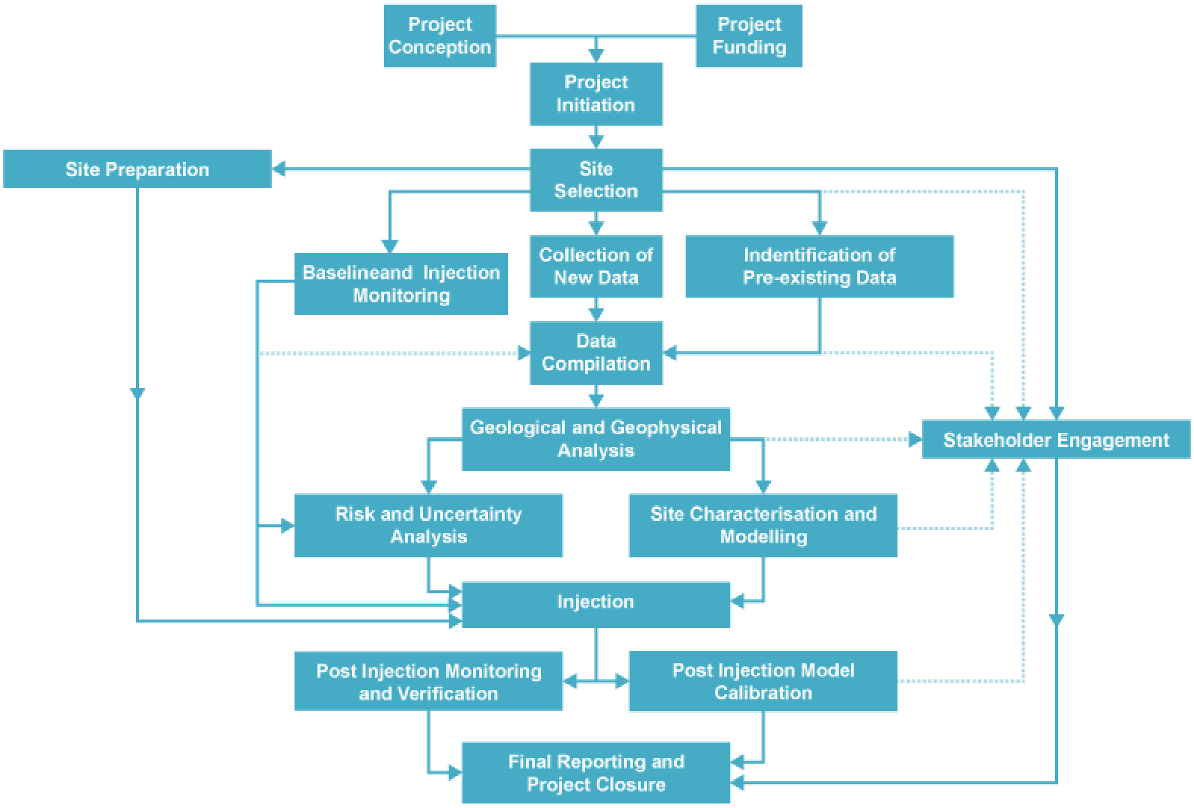


Figure 15 – An alternative work flow diagram for small scale demonstration projects.

Because of the manner in which most of the projects documented in this study developed, they are not new greenfield sites which commenced with an assessment of regional geology and then progressively narrowing down to detailed characterisation. For the most part they were associated with existing oil and gas developments and therefore could be considered as brownfield sites. The benefit of this brownfield starting point is that it enables the project to utilise the pre-existing data that were acquired often before there was any thought of, let alone the inception of the storage project. In the case of EOR or ECBM projects, the fact that storage operations are proposed or taking place within reservoirs that are actively producing oil or gas means that reservoir parameters and properties are likely to be well understood (Figure 16).

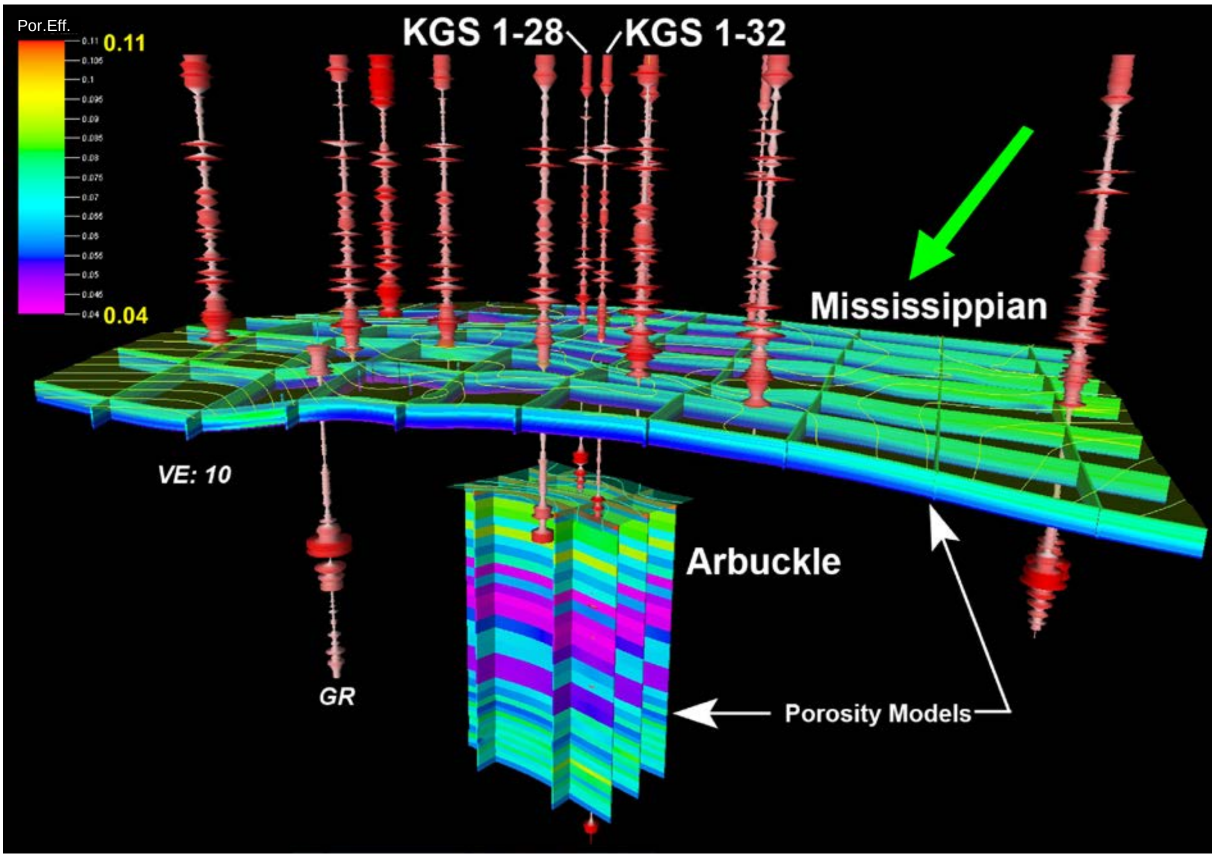


Figure 16 – Wellington Field – Porosity Fence Diagram. Pre-existing geological data used to develop a porosity fence diagram in the small scale field test in the Arbuckle Reservoir at the Wellington Field, Sumner County, Kansas (Watney and Rush 2011).

Similarly in the case of storage in depleted oil and gas fields, the previous phase of exploitation will in most cases have produced an extensive database for the project to utilise. In the case of the Lacq-Rousse Project for example, the Rousse depleted gas field (Figure 17), had been operational for over 50 years and therefore had comprehensive knowledge of the geology of the reservoir formation and a high degree of confidence in its likely behaviour during the storage phase.

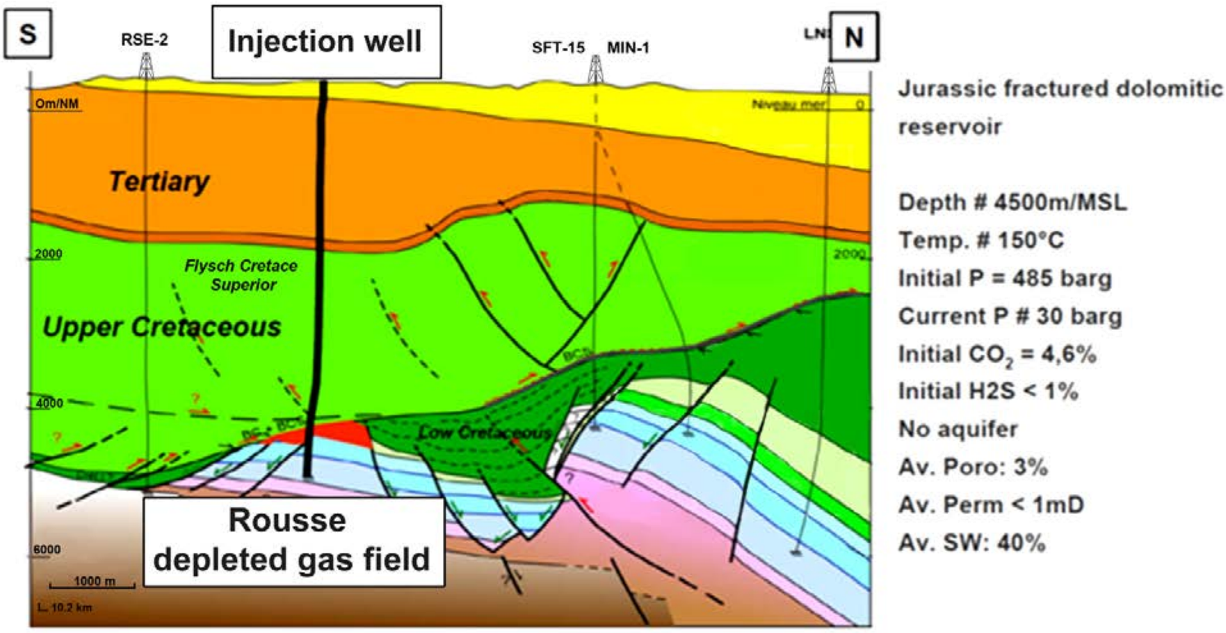


Figure 17 – The Lacq-Rousse Project – Example of a well characterised site prior to start of the storage project (Moulet 2009).

This may not always be the case with small production schemes, which may only have generated a small data set. An example of this is the Australian CO2CRC Otway Project (Phase I) which was conducted in a structure and reservoir previously exploited as the Naylor Gas field (Figure 18).

This small field was located on a feature identified through a 3D exploration seismic survey in a region of small gas accumulations and was developed using a single monobore well which was abandoned after two years of production when an increasing proportion of water made production uneconomic. As a consequence, the development left a smaller data legacy than would be found from a larger field. Nonetheless using these data, and constructing detailed static and dynamic models based on the information from Naylor 1 and other wells in other small fields in the same area, allowed for the project to conduct a detailed site characterisation before the first stratigraphic/ data well, CRC-1, was located and drilled. This well ultimately also became the injection well.

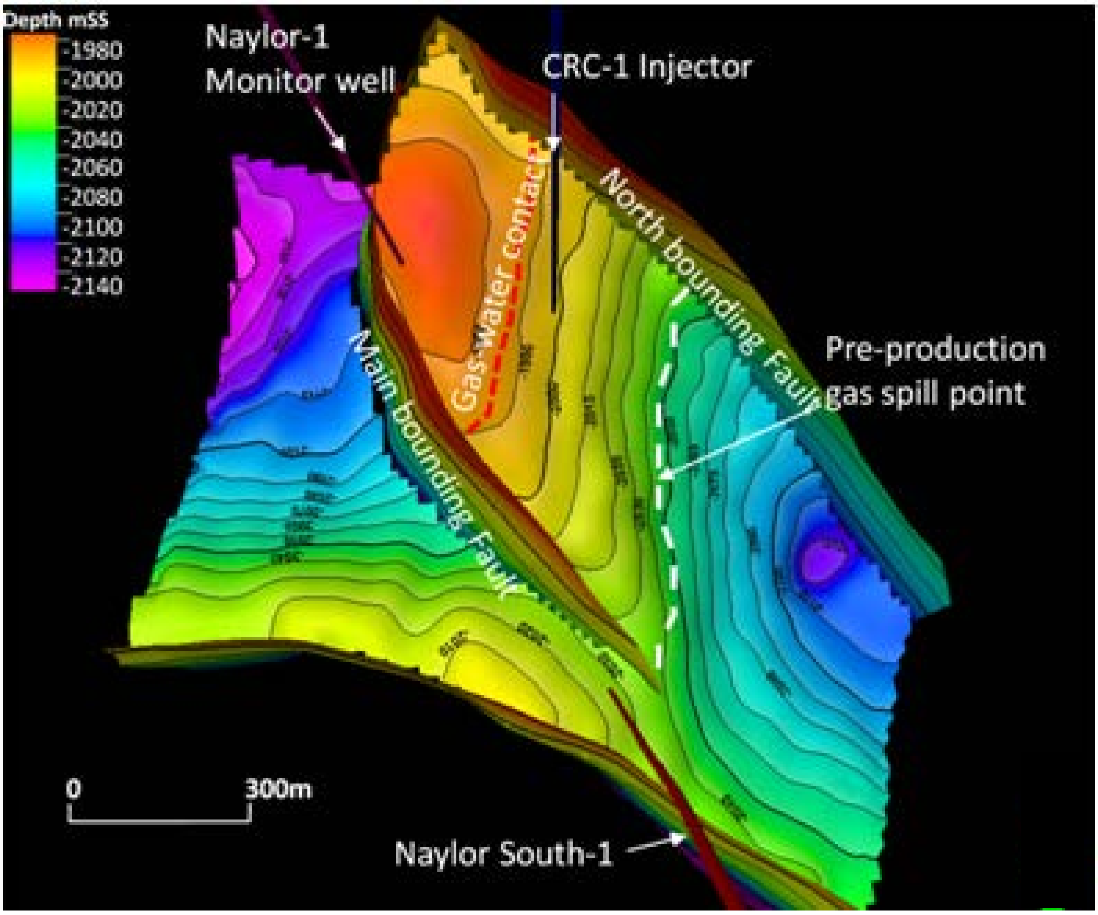


Figure 18 – The Naylor Field 3D structural model, including top reservoir horizon, faults, spill point, and post production gas-water contact. The Naylor Field, CO2CRC Otway Project, structural model (Dance 2013).

Storage sites which have an enhanced oil recovery component or those in depleted fields will be likely to have data sets which may be adequate for initial characterisation. But because of the inevitable pre-occupation of the petroleum industry with on-structure reservoir rocks where trapping of conventional oil and gas is likely to have occurred, it is likely that storage sites in deep saline aquifers will have relatively sparse datasets with any coring limited to the reservoir rock. In particular there is likely to be an absence of data or core from the overlying seal rocks. This may be particularly true in future anticipated large scale development, when storage may be targeted at formations that have never been the site of petroleum accumulations, or are the deeper parts of producing formations away from the structural highs that house the oil and gas accumulations.

In the 11 deep saline aquifer tests identified in this study six were conducted within the area or adjacent to producing or depleted oil or gas fields. In all these cases it is likely that the preliminary site characterisation will have benefited to some extent from data that had been collected during exploration and drilling operations, even where the information collected in the actual saline reservoir may have been limited. One site (Ketzin) was in the deeper portion of a gas storage structure; in another case (Otway II) the saline aquifer was in a shallower (stratigraphically younger) portion of the gas-bearing structure and the amount of information obtained from petroleum exploration and production relevant to the storage formation was quite limited. However, the data well for Otway I provided very valuable information, perhaps pointing to the benefit (in terms of data availability, logistics and cost) of undertaking multiple experiments at one well-known site rather than spreading activities over several sites.

The other saline aquifer tests were conducted in reservoirs that were not associated with petroleum production operations and were generally sited on the basis of their proximity to a power plant or a major source of industrial CO_2. In most cases, the storage formations were well known regionally from deep drilling, usually associated with petroleum exploration although in the mid continent area, deep injection wells were also a useful source of information. The Zerogen Project provides a cautionary example of the difficulties of setting out to try to prove up a storage site in a formation that was poorly known but geographically well positioned. It was anticipated that reservoir rocks with storage characteristics that would be adequate for a planned large scale storage project would be encountered. Extensive exploration and a small scale injection test revealed that the reservoir qualities did not meet the requirements of the proposed large scale project, leading to the project abandonment. This example highlights the risks that arise in undertaking a greenfield exploration program for a CCS project at any scale.

In most pilot projects, pre-drill reservoir characterisation consisted of the integration of regional geological and hydrogeological data. Generally the preferred storage reservoir had already been identified from the known regional geology, particularly where this was a petroleum producing formation elsewhere in the region. In a few projects 2D seismic data was acquired prior to the commencement of drilling. For example in the case of the MRSCP Appalachian Basin and Cincinnati Arch projects, the test sites were geographically well located adjacent to power stations but the local subsurface structure had not previously been defined to level of detail required, thus necessitating the preliminary seismic survey (Figure 19).

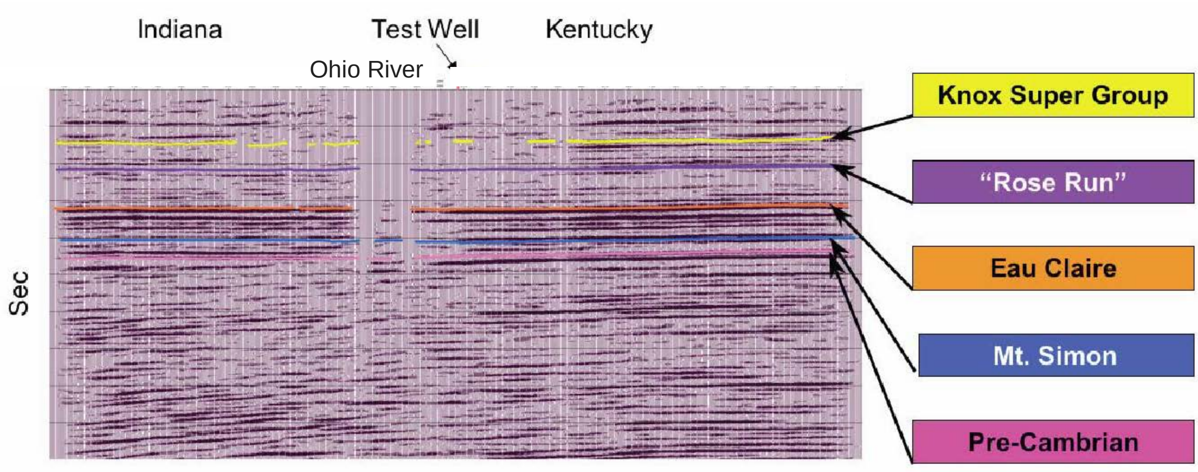


Figure 19 – Results of the 10-mile seismic survey confirmed the presence of continuous rock Layers with no deep faulting - Seismic lines acquired for reservoir characterisation in the MRCSP Appalachian Project (Wickstrom et al. 2009).

The development of a static (computer based) geological model does not seem to have been regarded as an essential early step in all projects. This impression may be partially due to the fact it is the injection result that is the focus of most of the papers and presentations available on line and the full extent of pre-injection characterisation that was carried out may not have been reported. In many cases where the characterisation of the injection site geology is mentioned it is a description of the reservoir properties, as known from the existing data that is discussed rather than the process of site characterisation itself.

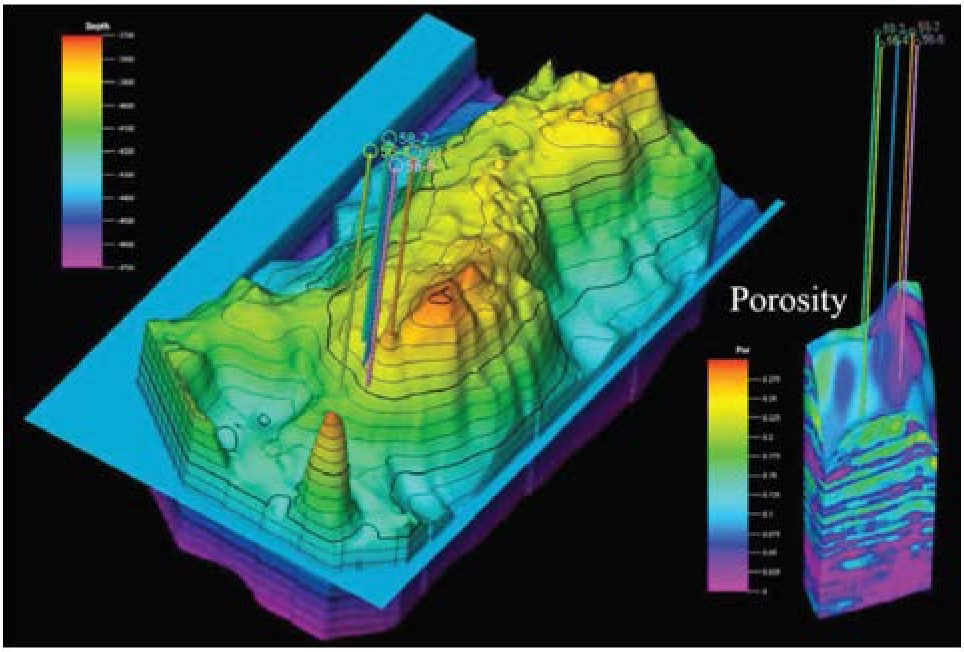


Figure 20 – Geomodel of the SACROC Phase II site depicting depth (left) and porosity (right). An example of a geological static model from the SACROC EOR Project (NETL Fact Sheet 2010).

Most of the projects have constructed dynamic models in order to model the migration paths and dispersal speed of the CO_2 plume, but it is not always clear whether this dynamic modelling pre or post-dated the drilling of the injection well or the injection itself.

In many projects, following initial compilation of regional geological information, the first and most critical phase is pre-injection data acquisition through the drilling of one (or more) data or exploration wells. Preferably these allow the coring and/or other sampling of both the reservoir and seal, and the acquisition of a complete set of petrophysical logs. These cover the need to characterise both reservoir and seal prior to CO_2 injection. However in many cases the well or wells which are used in the characterisation process have been for the identification of petroleum resources and may not have good information on the seals for example. But whether the subsurface data were collected for petroleum exploration or specifically for CO_2 storage, they provide essential input into both static and dynamic models before the injection phase is commenced.

There are apparent exceptions to this; for example the Zerogen storage project was carried out as a major exploration effort consisting of 12 wells seeking permeable reservoir sands, before a limited CO_2 injection test added confirmatory evidence that the storage resource was not suitable. During the course of the Zerogen program and before the injection test was commenced, an enormous amount of useful geological data was collected including 7km of core and the geological models were continuously updated to include the new findings from the wells. The ZeroGen Project underwent several changes in project objectives and aspired scale. This meant that the exploration program constantly changed as objectives changed and as funds were released in a piecemeal fashion.

Whilst almost all of the projects compiled and discussed in this Report are in sedimentary basins, there are two basalt projects. These two basalt tests appear broadly to follow much the process used by deep saline aquifer projects. The Carbfix project (Figure 21), which had a prior dataset based on the adjoining Hellisheidi thermal field, reports carrying out detailed field characterisation study at the injection site. This involved drilling the injection well, four shallow monitoring wells and five deep monitoring wells between 2004 and 2008, and testing a variety of monitoring technologies and studying the chemistry of the groundwater at the site.

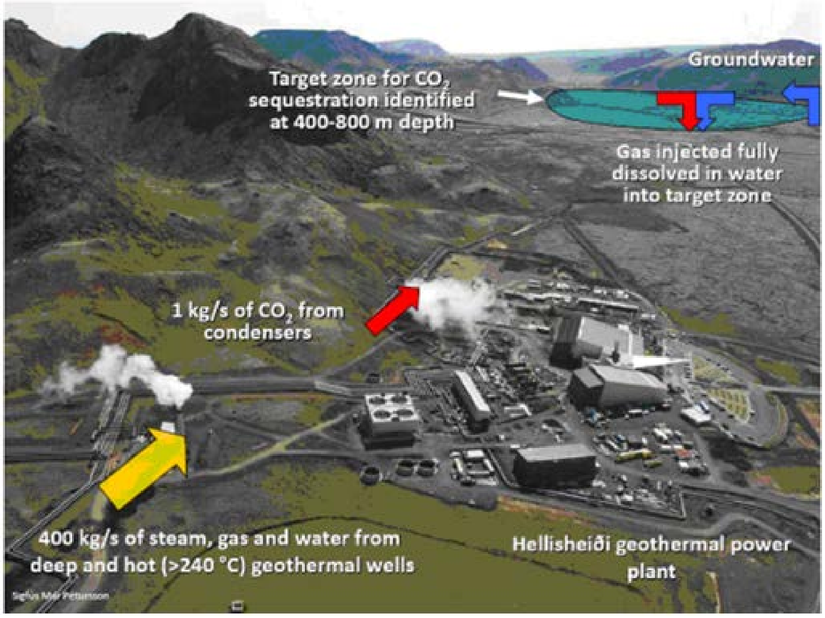


Figure 21 – Overview of the Hellisheidi Power plant showing proximity of the storage site to the geothermal sources (Matter 2011).

In the BSCSP Basalt project the chosen location was more of a greenfield site with little existing data. The anticipated geologic conditions at the site were first extrapolated from surrounding water boreholes and a large amount of environmental and subsurface data was collected for the characterisation including the acquisition of a four mile (6.4km) swath of vibroseis. As was the case with Carbfix, the focus of the site work was on the monitoring and verification of the injected fluid, although the two projects differ in the nature of that fluid. In the case of Carbfix, CO_2 was dissolved into water prior to injection, whereas in BSCSP the plan is to inject pure CO_2.

In the case of ECBM projects, as these are generally conducted in producing CBM fields, there is often a large amount of pre-existing core material available for analysis, as well as a number of production wells already drilled which can be used for monitoring. However, in projects such as Fenn/Big Valley, new evaluation wells were drilled prior to commencement of CO_2 injection in order to obtain fresh core material to test for degassing under controlled conditions to in turn carry out gas volume and composition analysis and for the measurement of sorption isotherms for a range of gases. Reservoir simulation models are reported from several of the ECBM projects together with cleat and fracture modelling. Several projects reported “project created” geological models and at least one constructed a geological model using industry standard software.

7.1.1. Lessons learned

Most small scale projects do not follow the theoretical pattern of project development that has been suggested in the literature as being optimal for large commercial scale operations.

Generally, small scale projects are opportunistic, typically initiated by research organisations; they rely on an alliance with industrial partners for operational expertise and access to suitable locations, site selection and therefore depends very much on which sites can be made available

Most small scale projects are located in brownfield sites where a pre-existing database help to minimise the extent of pre-injection characterisation necessary.

In most small scale projects, pre-drill reservoir characterisation typically consists of the integration of pre-existing geological and hydrological data. The degree to which new data is collected for this purpose varies but generally seems to be quite small.

Drilling purely for stratigraphic information is rare, with most projects only drilling the intended injection well, though it will generally be sampled to supplement the existing dataset, typically acquiring data on the sealing formations which are frequently not sampled in standard petroleum developments.

Storage sites within depleted fields or with an EOR component may only need minimal site characterisation, but deep saline reservoirs will usually be data deficient and require project specific data collection even when these reservoirs are located within the footprint of an existing production project.

Generally it does not appear that the majority of projects have felt the need for static geological models (to the extent that they are not widely reported), although this may be due to under reporting of the pre-injection workflow. However most do appear to have constructed dynamic models using known subsurface characteristics to assess migration pathways, but it is not always clear whether these pre or postdate the drilling of the injection well or injection itself.

In conclusion the degree of pre injection site characterisation that pilot scale projects have engaged in varies considerably. The variability reflects the range of sites chosen for the experiment including the availability of prior data, and the type of storage being investigated. Progress to larger scale demonstrations or full industrial scale projects will require a more extensive prior characterisation of the proposed site, and more exhaustive modelling than is seen in most small scale projects. Larger projects are also likely to benefit from early pilot scale projects. Many larger projects are also likely to benefit from early pilot scale projects.

7.2. Modelling and reservoir testing of small-scale CO_2 injection tests

Reservoir modelling, varying from simple analytical equations to complex 3D multi-phase transport models, supports all stages of a CO_2 pilot injection project. Usually, the complexity and predictive capabilities of the reservoir model improve over the length of the project as new data from reservoir studies (core, logging, seismic, hydraulic testing) and monitoring become available for model calibration. The database on pilot injection projects compiled for this Report contains information on the type of modelling software used as well as which reservoir studies were performed. Some details are discussed in the following sections.

After a site has been selected for CO_2 pilot injection based on existing data, additional reservoir studies need to be performed to produce data necessary for designing the actual injection test. This is particularly the case for injection into saline aquifers, for which there is only a limited amount of pre-existing data as opposed to storage in depleted petroleum reservoirs for which reservoir tests had been performed previously. The majority of pilot projects collected core from a new data well, which normally is sighted in the expectation that it will become the injection well. Where possible, data will also be obtained from new or existing observation wells. In some cases of CO_2-EOR projects or injection into depleted hydrocarbon reservoirs for which no new wells had to be drilled, existing core material will be tested for reservoir characterisation. Not surprisingly for almost all projects, new or existing core is seen as essential. The data sources for seismic surveys are less clear although more than 20 projects acquired new seismic data, at least three of which performed repeated 3D seismic surveys (Figure 22). However a large number of projects do not indicate that they used or had access to seismic records, which is somewhat surprising, given the perceived utility of the technique to storage projects

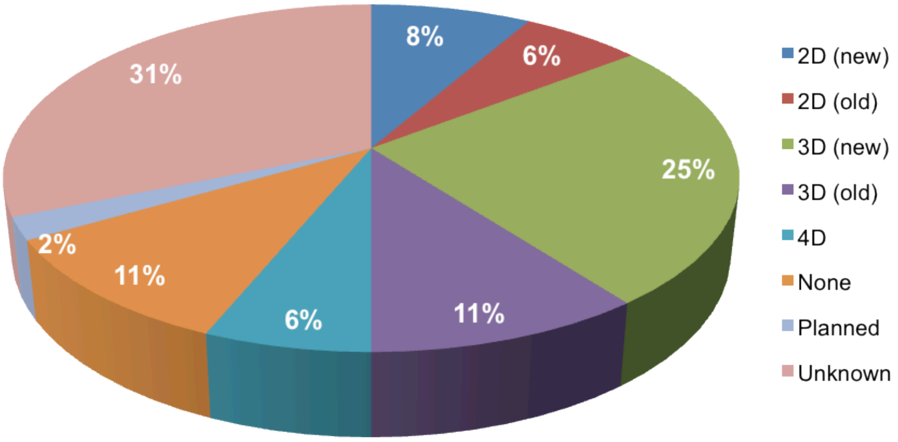


Figure 22 – Seismic Data collection for reservoir studies at pilot CO_2 injection projects.

One important aspect with respect to reservoir studies that could not be captured in a meaningful way in the database is information about pre-injection reservoir testing (i.e. injectivity test, step-rate test), as these test results are reported only for very few pilot injection operations. Short-term, pre-injection injectivity tests would provide valuable data before embarking on the full injection stage of the pilot project to confirm that the targeted interval is adequate for the desired injection rates under the planned injection program.

The simplest and cheapest test that could be performed would be the production of formation water, the results of which can be used to infer the possible CO_2 injection rates from the water production rate. This was done for example at the beginning of the Otway 2B residual saturation test (Figure 23). The production of formation water from the very permeable sandstone aquifer revealed some potential sanding issues and helped in terms of ensuring better completion of the screens in the injection interval. The produced water saturated with CO_2 was later re-injected to displace the injected CO_2 and drive the reservoir to residual saturation.

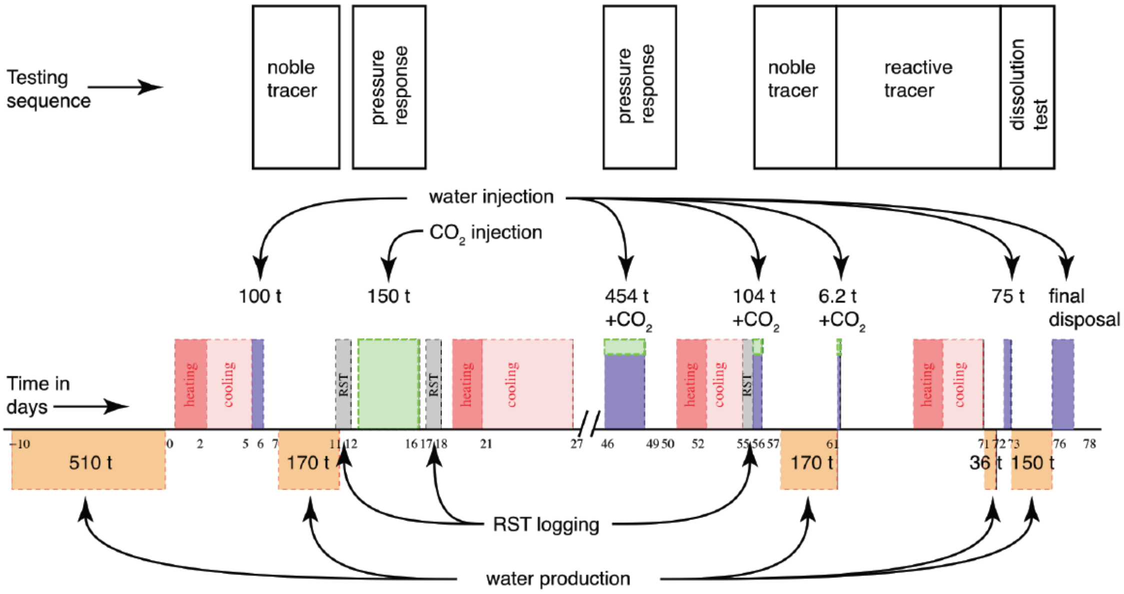


Figure 23 – Sequence used in the residual saturation and dissolution test at the CO2CRC Otway pilot site (Paterson et al., 2013).

Independent from the example above, which uses water injection as part of a test sequence, water injection by itself can be a useful way of confirming that the formation can accept fluids. Depending on the availability and their composition, either surface water or formation water could be injected. The latter is preferred because different chemistry of the injected water can cause scaling issues in the injection interval. For example, a pressure-transient analysis of a standard interference well test and breakthrough-curve analysis for a two-well recirculation tracer test were used to successfully characterise the hydraulic parameters of the injection interval and calibrate reservoir models at the Frio Brine project prior to CO_2 injection.

Depending on the availability, prior to the main test, small amounts of CO_2 could also be injected to better constrain relative permeability and temperature effects in the borehole and near-borehole environment. For example, in addition to collecting 7000 m of cores from 12 wells Zerogen tested 5 of their appraisal wells; 4 through water injection and 1 through CO_2 injection. The tests resulted in higher than expected pressure build up, indicating inadequate injectivity for the desired CO_2 injection volumes. Hence, one of the key findings from the ZeroGen experience is that early dynamic flow testing of a single or small number of wells is relatively expensive but is far more valuable than collecting core data from a larger number of cheaper stratigraphic wells. Similarly, the MRCSP Appalachian Basin (Burger) Phase II test encountered lower-than-expected injectivity and concluded that field tests were needed to confirm that the injectivity predicted by logging and core testing methods was correct.

Two small-scale huff and puff tests were performed at the Fenn-Big Valley ECBM test site after the well was initially produced and step-rate tested for permeability estimation. Each test consisted of 3 stages (injection, soak and production period). The injection stream consisted of pure CO_2 followed by 13% CO_2 & 87% N_2 in the first test, and pure N_2 followed by 47% CO_2 & 53% N_2 in the second test. The five simulation software packages tested were incapable of predicting the produced gas composition in the field test with any degree of accuracy. At the JCOP Yubari-Ishikari ECBM project, various injection tests were performed including: fall-off, CO_2 huff'n'puff, step rate and N_2 flooding. Therefore experience to date does point to the value of early small scale injectivity test, prior to commencement of the full test. Whilst it does add modestly to the overall cost of the pilot project it can prevent the expenditure of a great deal of money to fully build the pilot project, only to find that the injectivity is too low for the project as planned.

7.2.1. Reservoir Modelling

Reservoir simulations are an important element of the workflow associated with most CO_2 injection projects. Reservoir models for injection pilots are used to:

1. Design the injection test by constraining bottomhole injection pressure, injection rate, maximum radius of the CO_2 plume, storage capacity, storage mechanisms.
2. Predict plume and pressure behaviour for permitting by the regulator.
3. Design an appropriate monitoring and verification scheme.

Pre-injection reservoir models need to be continuously updated by calibration to actual test data, which in turn leads to an improved understanding of the reservoir and increases the confidence of the regulator and public that stored CO_2 behaves within predicted parameters.

Previous studies have identified a lack of data from CCS pilot or demonstration projects that could be used for the calibration of numerical modelling efforts, particularly for the post-injection phase (Michael et al., 2010). Only a handful of CCS pilot projects had been in operation at that time (i.e. Frio, Otway, Ketzin, Nagaoka), and some of the project results had not been published. Since then, new CO_2 injection projects have been completed and there has been an increase in publications comparing reservoir simulation results with observed data from CO_2 injection pilots around the world (eg. Bacon et al., 2009; Ennis-King et al., 2011; Pamukcu et al., 2011).

Simulation software that has been used for modelling CO_2 injection at pilot sites can be divided into two categories (see summary table/project database):

1. Commercial software developed primarily for the petroleum industry, and adapted in various ways for CO_2. The most common choices are Eclipse (Schlumberger), GEM (from the Computer Modelling Group), and VIP (Halliburton).
2. In-house or research software, usually developed in research institutions. These codes tend to be more specialised, and do not have the wide range of features to deal with general petroleum simulation. TOUGH2 (Laurence Berkeley National Labs) and its derivatives as well as STOMP (Pacific Northwest National Labs) are the most widespread examples, but there are others available.

Code comparison studies have shown that most of these modelling codes produce repeatable results when simulating CO_2 geological storage (Pruess et al., 2004; Class et al., 2009). An ongoing model comparison initiative, Sim-SEQ, attempts to better understand and quantify uncertainties arising from conceptual model choices when using the aforementioned model codes (Mukhopadhyay et al., 2012). Therefore, the choice of software depends mainly on the respective operator and scientific collaborator for each CCS pilot project. In the US, for example, CCS is largely funded through USDOE Regional Partnerships Program and research often is provided by the National Laboratories. Therefore, projects in the Blue Sky Carbon Sequestration Partnership (BSCSP) and the Midwestern Regional Carbon Sequestration Partnership (MRCSP) use predominantly PNNL's STOMP for their reservoir simulations, whereas SECARB and WESTCARB use LBNL's TOUGH2. Other US regional partnerships and other international projects with strong industry participation use the more expensive, but often more user-friendly, commercial software such as Eclipse, GEM or VIP. This is particularly the case for CO_2-EOR projects, for which in most cases a reservoir model already exists. More specialised software is needed in the case of CO_2-Enhanced Coal Bed Methane projects. COMET3 is an example of software that can simulate the additional feature of enhanced fractures and methane desorption and was used in MGSC ECBM pilot projects.

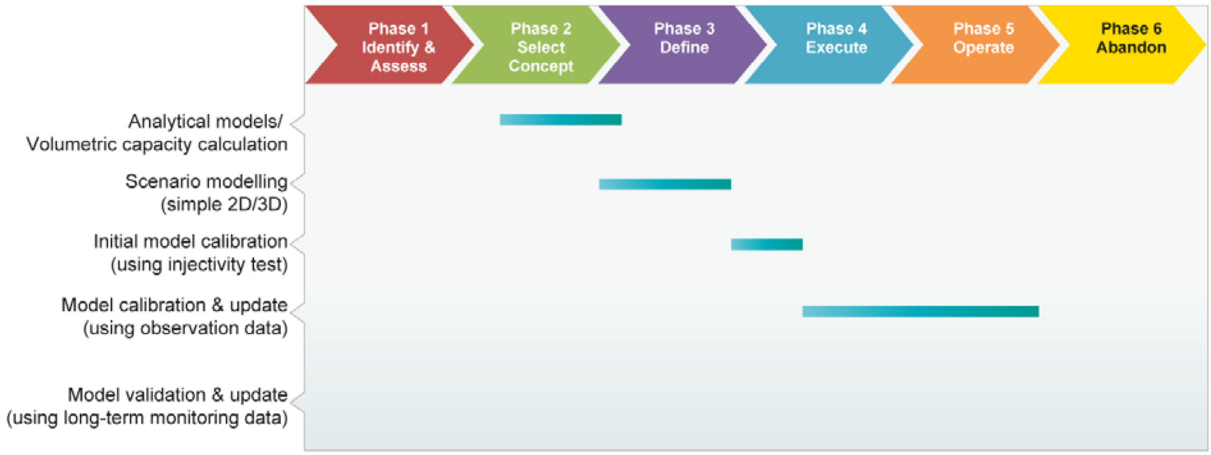


Figure 24 – Reservoir modelling workflow diagram.

It is still the case that the majority of the published simulation results from the various pilot projects are based on pre-injection models that were used for injection and M&V design and permitting. One of the reasons for this is that many of the projects are relatively recent and model calibration is either ongoing or publications are in preparation. In other cases, projects came to an end shortly after actual data were collected and the results of calibration efforts were never made public, which is unfortunate.

Model calibration is particularly important in the cases of storage in deep saline aquifers which have a large uncertainty associated with their reservoir parameters as opposed to projects such as depleted oil or gas reservoirs, or EOR or ECBM projects for which well-characterised reservoir models often already exist pre-CO_2 injection. For example, the reservoir model for the K12-B1 well in a gas field in the Netherlands was calibrated to an approximately 17 year production history and could accurately predict the pressure response for 2 short-term CO_2 injection tests (van der Meer et al., 2006; Figure 25)

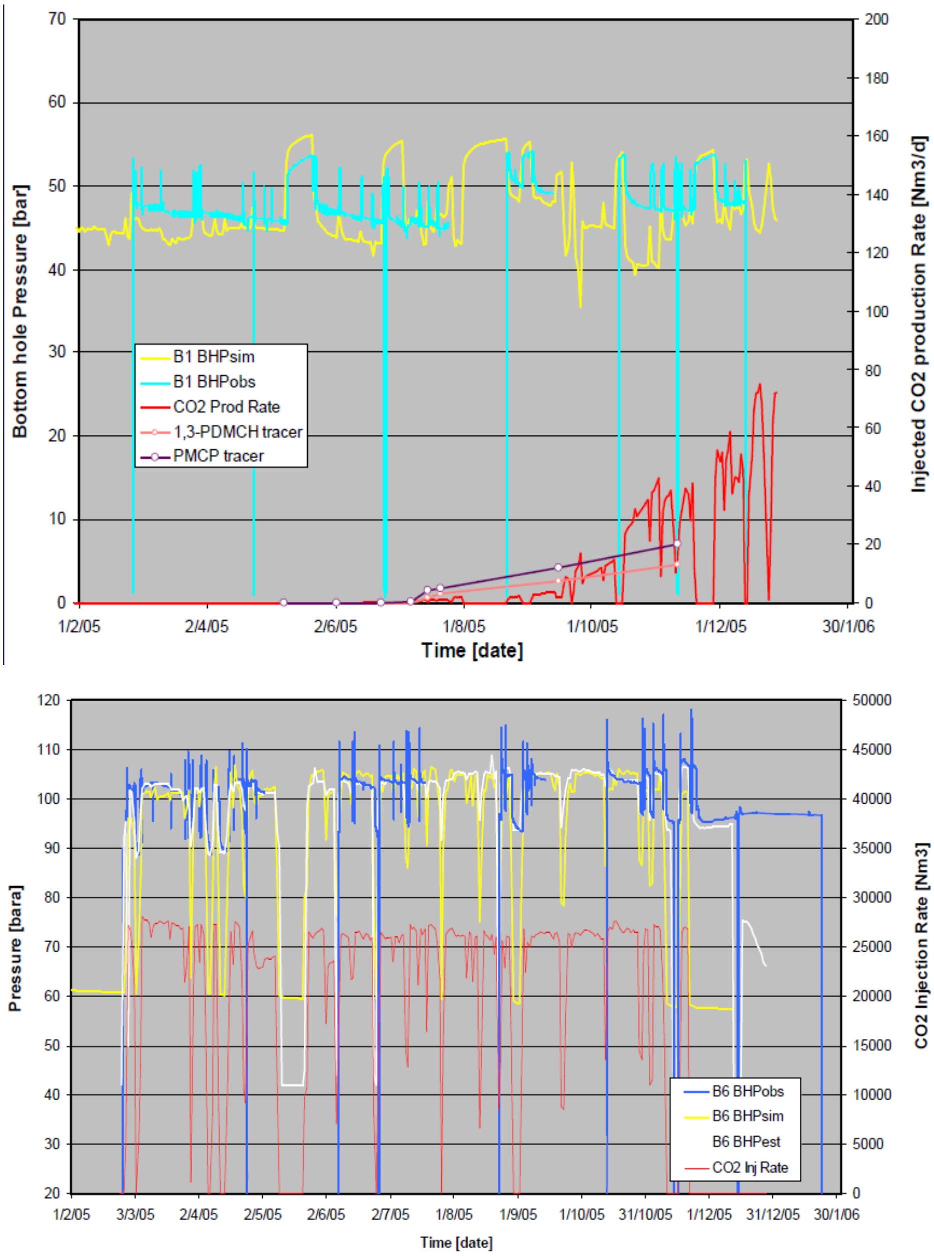


Figure 25 – Comparison of measured and modelled bottom hole pressures for the CO_2 injection test for the injector K12-B1 (top) and the observation well K12-B6 (bottom); van der Meer et al., 2006.

The geological models and the derived simulation models at the CO2CRC Otway I Pilot site were able to fit most of the key features of the field data, including the downhole pressure measurements and the arrival time at the observation well (Figure 26). When fitting to the downhole pressure only, the observed arrival time was in the range of uncertainty of the model predictions (Ennis-King et al., 2011). The use of multiple geostatistical realisations of heterogeneity demonstrates the importance of capturing the range of uncertainty in the geology, and the consequent scatter in forward predictions. Pressure data from downhole gauges has proved to be very valuable for adjusting the bulk reservoir properties and relative permeability curves in the simulation model, and improving the accuracy of simulation predictions. Temperature profiles are shown in Figure 27.

The CO2CRC Otway IIB test was the first to specifically determine the CO_2 residual saturation in a saline aquifer during injection for various ranges of investigation. The calibration of the model using observed downhole pressures for different phases of the test resulted in an average value of the CO_2 residual saturation between 15-19 % (Figure 28).

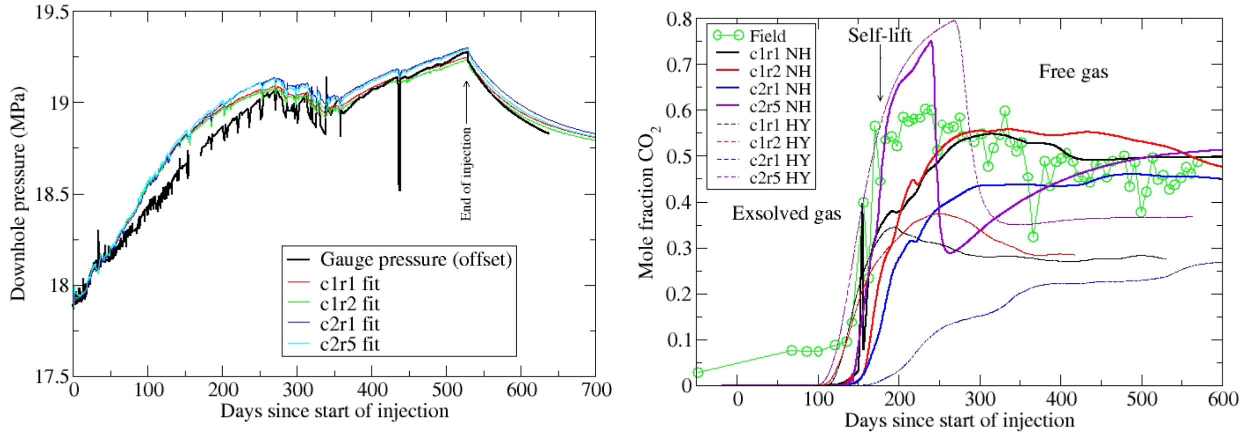


Figure 26 – Comparison of modelled and observed data during the CO2CRC Otway I test (Ennis-King et al., 2011). Left: downhole pressure data at the injection well CRC-1 for four different realisations (c1r1, c1r2, c2r1, c2r5 fit) of the geological model. Right: CO_2 concentration at the observation well Naylor-1 for the same geological realisations as in the top figure; NH and HY indicating non-hysteretic and hysteretic relative permeability curves, respectively. LaForce et al. (2013).

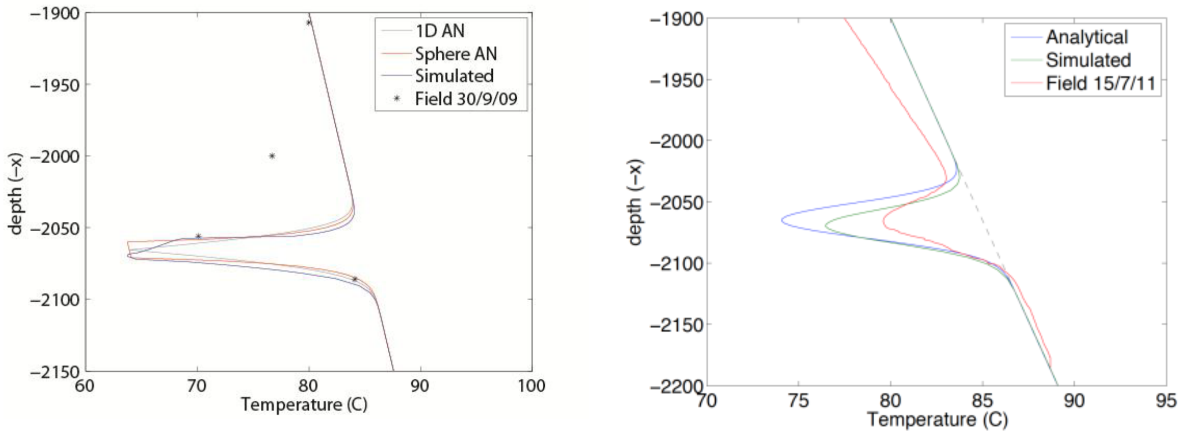


Figure 27 – Comparison of 1D vertical temperature profiles for analytical, simulated and field data for 31 days (left) and 685 days (right) post injection of the Otway I test. (Ennis-King et al., 2012).

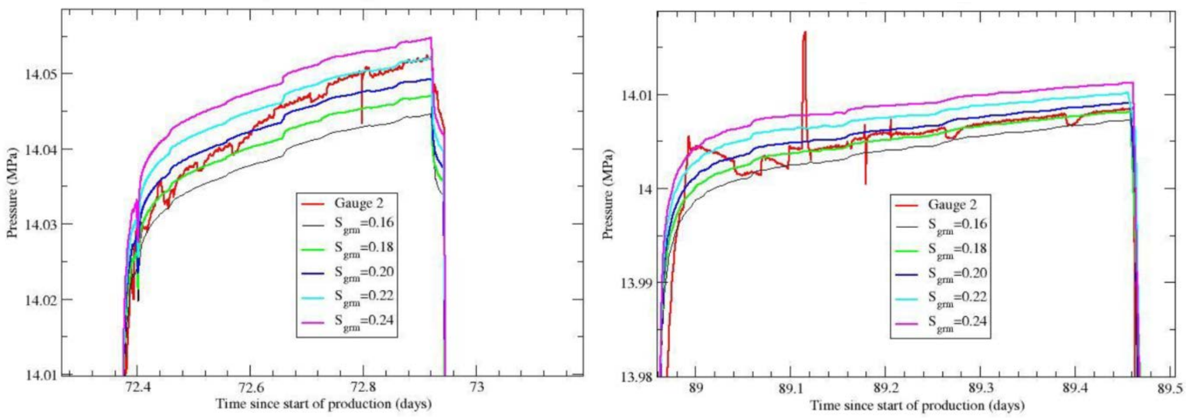


Figure 28 – Calibration of CO_2 residual saturation values (Sgrm) by comparing modelled and observed bottom hole pressures from two stages of the Otway IIB test.

At PennWest's Pembina CO_2-EOR pilot in Alberta, Canada, the reservoir model was successfully history matched to the pre-EOR production and was able to predict CO_2 breakthrough at the closest producer. However, at the other producers, observed breakthrough was faster than predicted and actual oil and water production were lower (Figure 29). One explanation for the limited predictive capability of the existing reservoir model was the inadequacy of the model to handle viscous fingering, which triggered the decision to develop a new model for future use (Penn West Energy Trust, 2007).

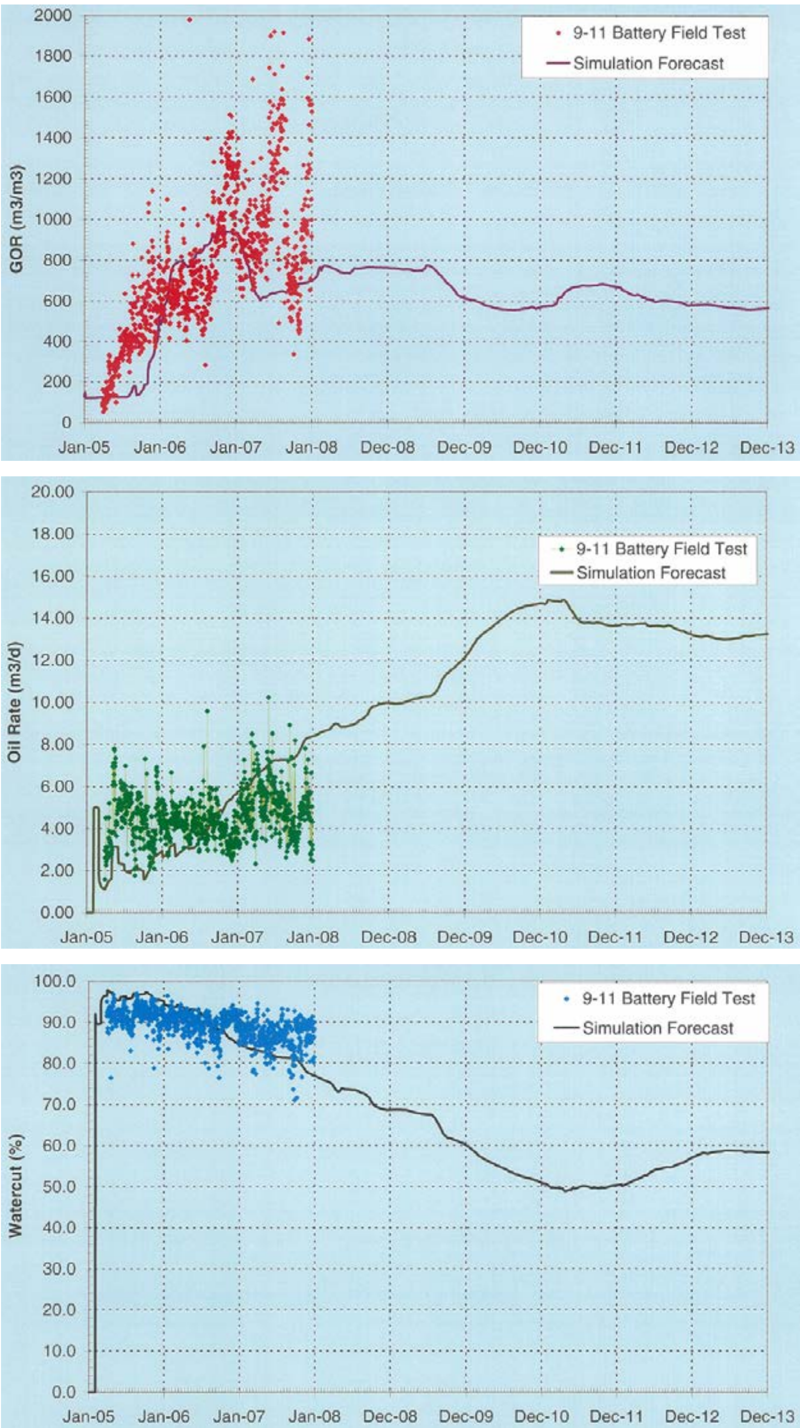


Figure 29 – Comparison of simulated versus observed CO_2-oil ratio (top), oil production rate (middle) and water production rate (bottom) in response to CO_2 injection at the Pembina Cardium CO_2 EOR pilot (Penn West Energy Trust, 2007).

At the Frio Brine pilot project the RST logging tool was used to calculate CO_2 saturations and to document the vertical development of the CO_2 plume over time (Hovorka et al., 2006). The largest difference between observed and modelled saturations at the observation well was that the CO_2 plume migrated more effectively upward through the layered muddy sandstones (Figure 30), suggesting that layering of low permeability units was more discontinuous than assumed in the geological model

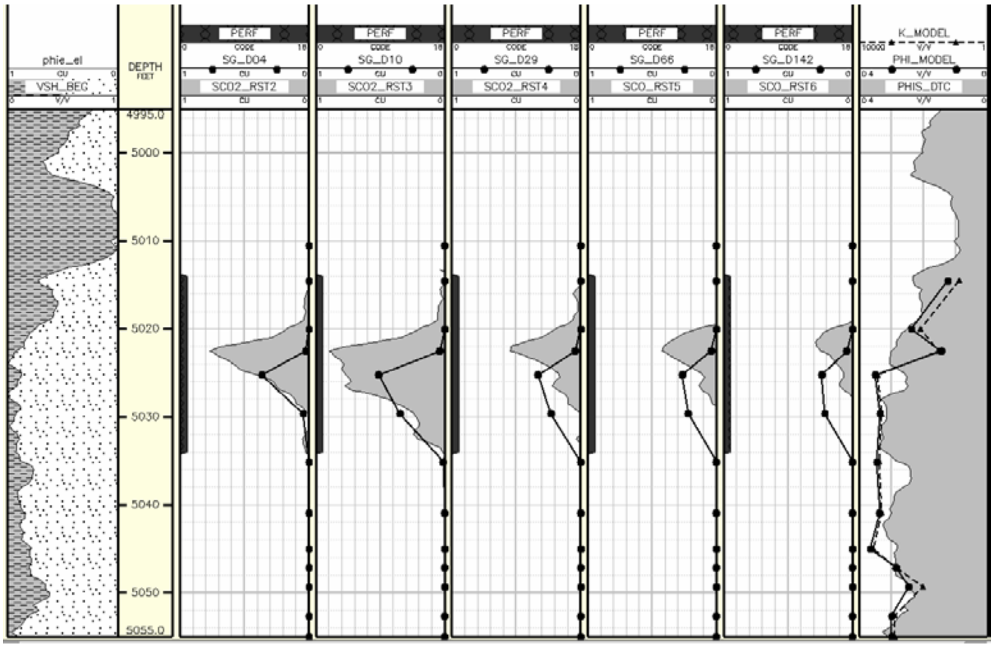


Figure 30 – Comparing CO_2 saturation calculated from RST logs and predicted by reservoir simulations at the observation well of the Frio Brine project (Hovorka et al., 2006).

In the MRCSP pilot projects, the main parameter used to calibrate the models was downhole pressure in the injection well and observation wells (Figure 31 and Figure 32). It was necessary to revise the initial models to a variable injection rate based on the actual flow rates observed at the injection wellheads. The Michigan Basin site model was calibrated to downhole pressures measured in both the injection well and the deep monitoring well for the initial injection (Figure 30). In model calibration, the permeability distribution in the model was scaled from an original average value of 22 to 50 mD, as indicated by reservoir testing analysis (Bacon et al., 2009). For the Cincinnati Arch pilot test simulations, a brine injection test was used initially to calibrate bottom hole pressures by adjusting the intrinsic permeability (MRCSP, 2011). For the subsequent CO_2 injection test, a CO_2 relative permeability equal to one surprisingly resulted in the best model calibration (Figure 32), but no other CO_2 relative permeability – saturation relationships could produce similar fits of modelled and observed pressures (MRCSP, 2011).

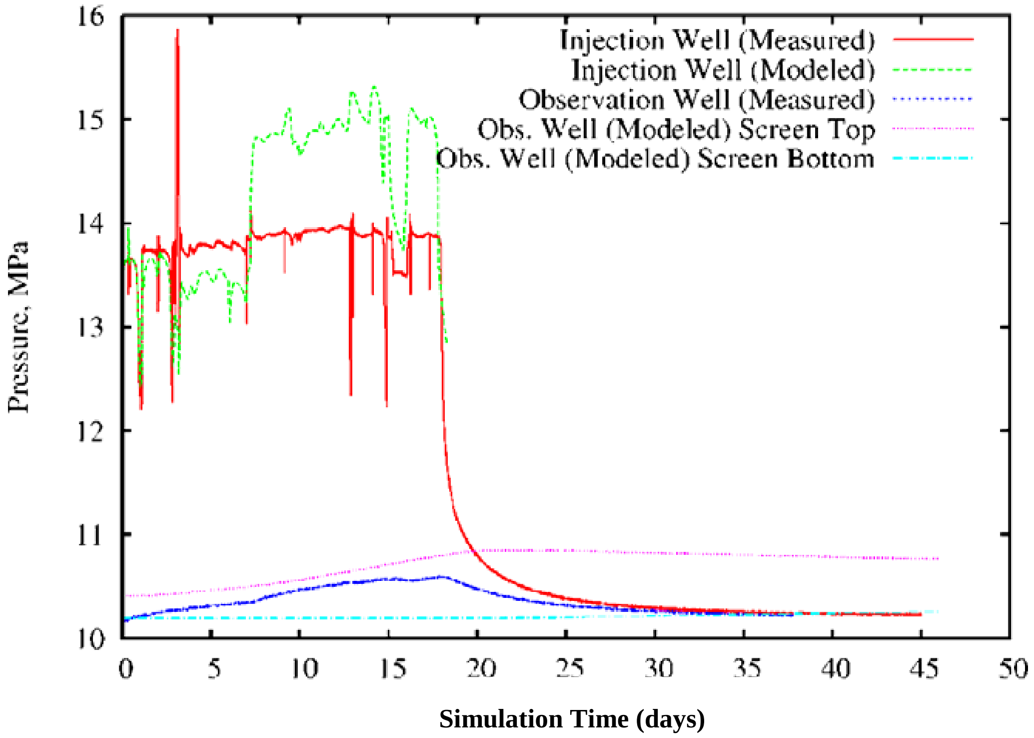


Figure 31 – Injection test results from MRCSP's Michigan Basin Phase II injection test comparing measured and simulated pressures at the injection and observation wells (Bacon et al., 2009).

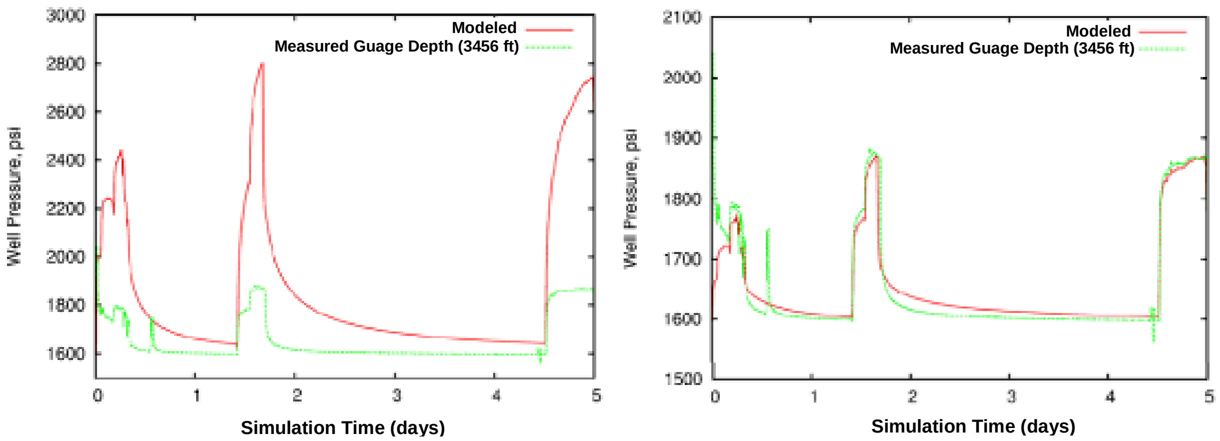


Figure 32 – Comparison measures and modelled well pressures at the MRCSP Cincinnati Arch pilot site. Left: assuming Fatt and Klikoff CO_2 relative permeability relationship and intrinsic permeability from brine injection test. Right: assuming CO_2 relative permeability = 1 (from MRCSP Cinncinnati Arch Final Report, April 2011).

The MRCSP (2011) reservoir simulations were used to:

1. Design the injection system by providing information on important system metrics such as sustainable injection flow rates, injection pressures, and CO_2 migration rates.
2. Support UIC permitting by determining the area of review, the long-term CO_2 migration and by providing confidence that the injection system would not affect underground sources of drinking water. Both CO_2 saturation and pressure were requested for the permit, but it appears that CO_2 saturation was viewed as the more critical parameter.
3. Develop the monitoring program using basic information such as pressure buildup rates, CO_2 migration extent, and temperature changes. For example, at the Michigan basin site it was determined that CO_2 breakthrough may not extend to an existing monitoring well, which was then re-completed with a deviated completion string to get it closer to the injection well. Also, simulated CO_2 saturation was compared to cross-well and vertical seismic observations.

History matching of the injection test at the Ketzin CO2SINK site in Germany was performed by adjusting the horizontal and vertical permeability until a close fit was achieved between simulated and observed bottom hole pressures (Pamukcu et al., 2011; Figure 33). Although the observed breakthrough of CO_2 at the closest monitoring well was within one day of the model prediction, the model underestimated the arrival of CO_2 at the more distant observation well (Figure 34). The reason for this mismatch is probably due to the incorrect interpretation of the location of high-permeability channel sands in the geological model (Pamukcu et al., 2011).

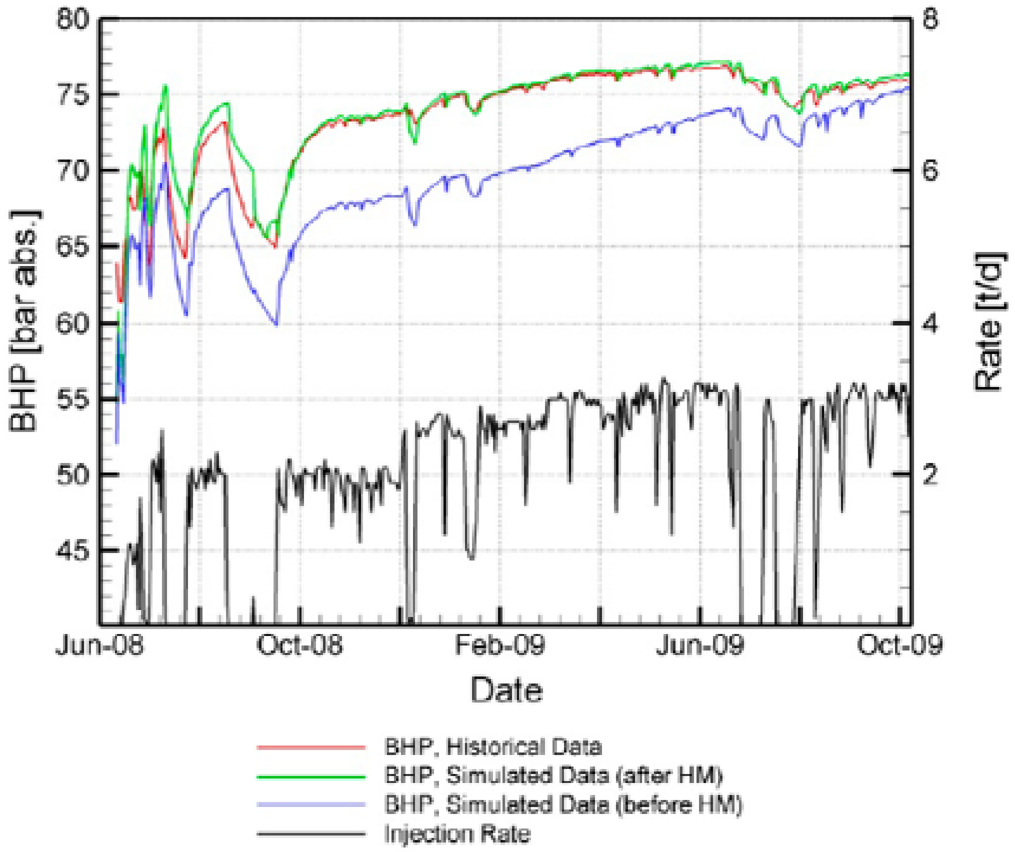


Figure 33 - Measured and simulated bottom hole pressures at the injection well Ktzi 201 at the Ketzin CO_2 pilot project (Pamukcu et al., 2011).

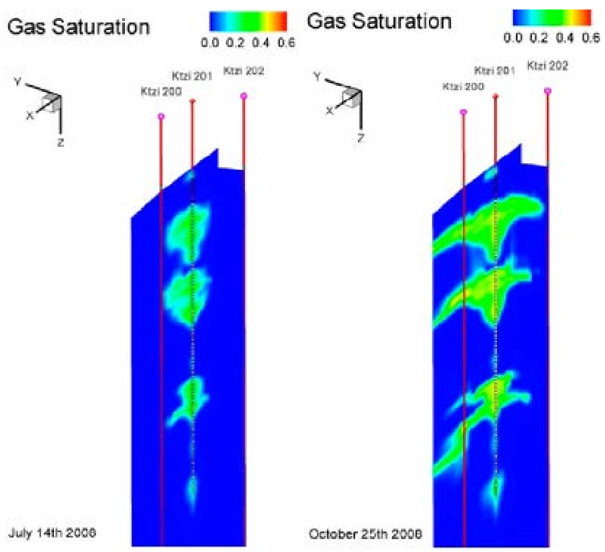


Figure 34 - Simulated CO_2 saturation maps at breakthrough times at observation well Ktzi 200 (left) and Ktzi 202 (right); the actual breakthroughs occurred on July 15th 2008 and March 21st 2009 (Pamukcu et al., 2011).

At Nagaoka, Japan, researchers used the inverse modelling code iTOUGH2 to calibrate the CO_2 injection test and to constrain the most sensitive parameters, e.g. permeability and CO_2 residual saturation (Sato et al., 2006). Interestingly, the best match between simulated and observed bottom hole pressures was obtained by using zero residual CO_2 saturation (Figure 35).

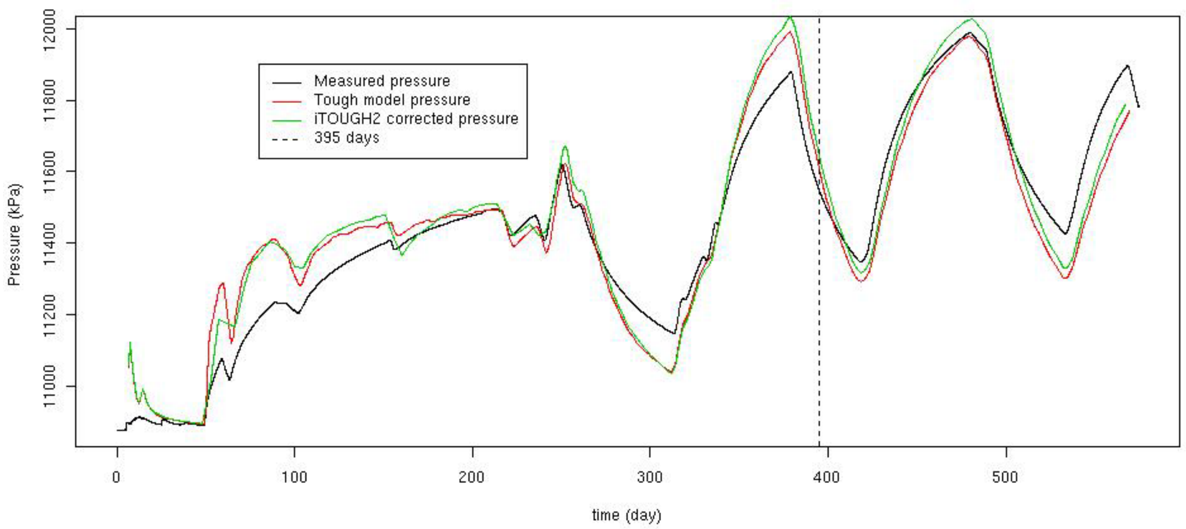


Figure 35 - Comparison of simulated and observed pressures at an observation well during the pilot injection at Nagaoka (Sato et al., 2006).

Mito et al. (2013) investigated the impacts of formation water composition on the migration of the CO_2 plume at Nagaoka. A comparison of their TOUGH2 and ChemTOUGH2 simulation results with well observations () suggests that accounting for the salinity of formation water is important for accurately predicting CO_2 breakthrough for times and distances at which buoyancy is the dominant driving force for CO_2 migration; e.g. at observation wells that are reached by the CO_2 plume post-injection. Including chemical reactions did not improve the calibration of CO_2 breakthrough; however is deemed to be important for predicting short-term calcite precipitation and long-term mineral trapping (Mito et al., 2013).

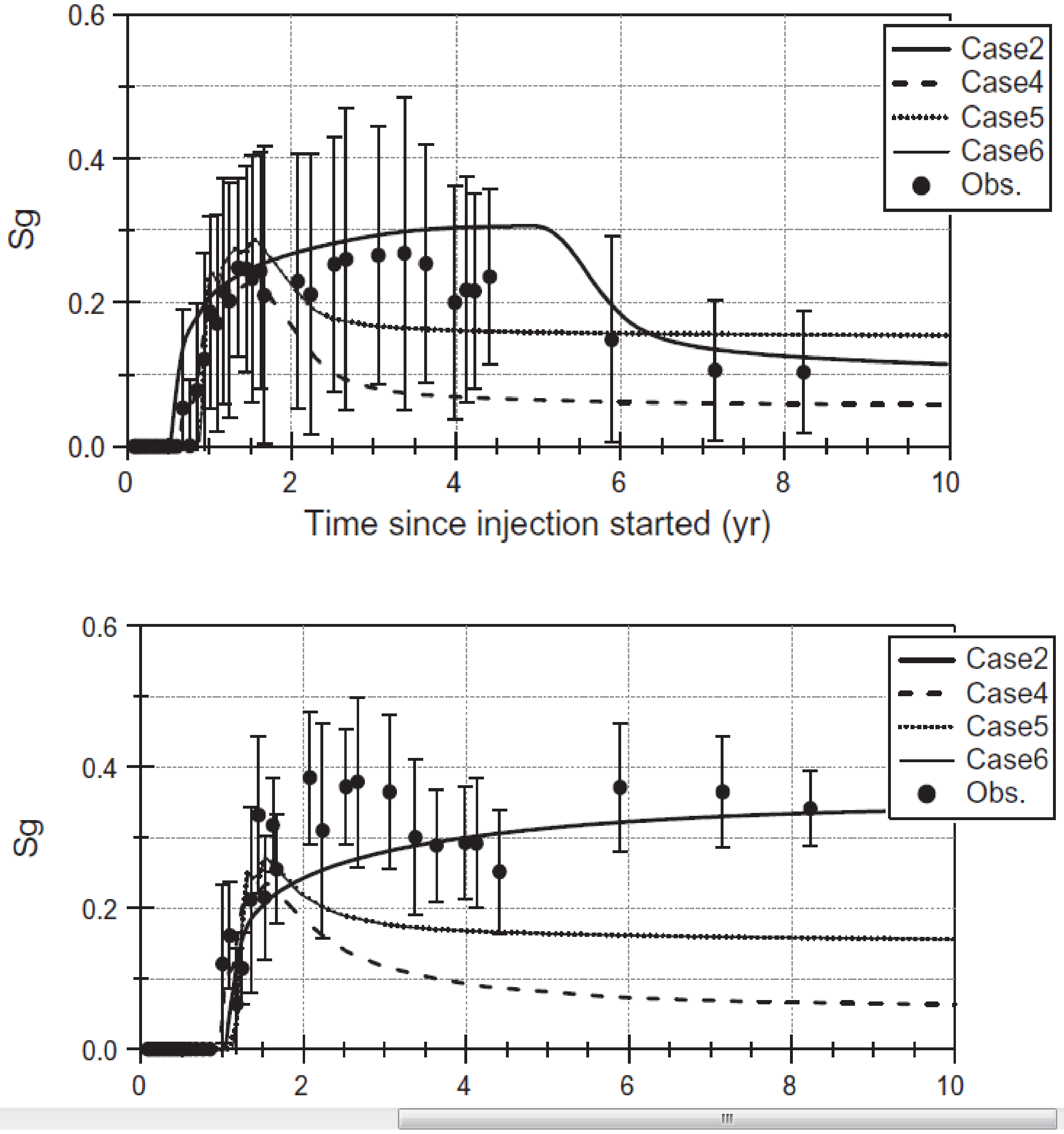


Figure 36 – Comparison of simulated and observed CO_2 saturations in monitoring wells OB-2 (top) and OB-4 (bottom) at the Nagaoka pilot site. Case 2: 0.8 wt% NaCl, no chemical reactions, Sgr = 0.05; Case 4: Nagaoka formation water composition w/chemical reactions, Sgr=0.05, Case 5: formation water collected prior to CO_2 injection, w/chemical reactions, Sgr=0.15; Case 6: solution in equilibrium with eight selected minerals, w/chemical reactions, Sgr=0.15. Mito et al. (2013).

7.2.2. Lessons learned

Reservoir simulations are performed routinely to assess CO_2 injection tests and provide valuable information for system design, permitting, and monitoring. The simulations are also useful for some less obvious functions including (MRCSP, 2011):

1. Models provide a systematic framework for integrating site characterization data and can reveal data gaps as well as the need for better understanding the geologic system.

2. Graphics and visualization of model results can be a valuable communication tool and can help people better understand CO_2 storage. However, it is important to associate the model results to surface features for reference so that simulations do not appear conceptual and detached from reality.

3. Reservoir simulations can build confidence in the CO_2 storage process if the models demonstrate that the project is thoroughly researched, well designed, and properly operated.

In most published cases, the models provided an adequate simulation of the CO_2 storage process, particularly in the prediction of the pressure response during injection. However, very rarely could the models describe fully the entire CO_2 storage process. Generalised and specific findings from CO_2 pilot projects are summarised below:

- Generally, the more site characterization data available, the better the match between model predictions and observations; which implies that models for CO_2-EOR projects or injection into depleted hydrocarbon reservoirs could be better calibrated to actual geologic conditions than injection tests in deep saline aquifers.

- Short-term reservoir tests (on the order of days) in the form of water/brine injection or production helped early-stage model calibration by better constraining reservoir parameters and defining appropriate injection rates.

- Given the small volumes of injected CO_2 for pilot sites, plume visualisation through geophysical methods is difficult and models are mainly calibrated to well observations (1-3 wells) in relatively close distance from the injector.

- The initial model predictions of CO_2 breakthrough at observation wells were generally within a predicted range of uncertainty. However, in most cases the actual observations led to the improvement of model parameterisation.K

- There is still a lot of uncertainty regarding CO_2 relative permeability and CO_2 residual saturation as shown by for example unusual calibration results from the Nagaoka (zero residual saturation) and the Cincinnati Arch pilots (CO_2 relative permeability equal to 1).

In most cases, projects follow a generalised workflow for reservoir simulations (Figure 37), which consists of:

- Analytical injection model and volumetric storage capacity estimations during site screening.
- Simplified, possibly 2D-radial, scenario modelling using homogeneous parameter distributions including uncertainty analysis during the pre-feasibility phase of a project. Model parameterisation is based on pre-existing and literature data.

- Predictive modelling of the injection process in specific reservoir intervals during the detailed site characterisation phase. Additional data from core analysis, logging and initial well tests are used to better constrain reservoir parameters. Well test (i.e. brine injectivity test) will provide data for initial model calibration.
- Model calibration and validation during the injection and post-injection phases. Measured data from the M&V program are compared to model predictions and the model is continuously updated resulting in improved confidence in the model's predictive capability.

Obviously, if pre-existing data are available in the site screening phase (e.g. depleted reservoirs with production history), then fewer additional tests are needed in the site characterisation phase and presumably less adjustments to the reservoir model are needed throughout the pilot CO_2 injection project. Nonetheless, some of the critical parameters specific to CO_2 injection, i.e., CO_2 residual saturation, relative permeability, dissolution rates and temperature impacts can be constrained only by calibrating the model to actual field observations. Therefore, model calibration needs to be a continuous process throughout the lifetime of an injection project by honouring new observation data and thereby improving predictions of plume migration into the future.

As in any other modelling field, the type, resolution and dimension of the reservoir model should be appropriate to the specific requirements and objectives of a project. Reservoir models associated with pilot projects that have research objectives related to the detailed behaviour of CO_2 in the subsurface (dissolution rates, residual saturation, CO_2-water-rock interactions) may require high resolution models and extensive computational effort. However, depending on the complexity of the subsurface, simple 2D radial model may be sufficient to predict the maximum plume extent and, in conjunction with M&V, satisfy regulatory requirements for a relatively simple test to demonstrate safe injection and storage
of CO_2. The more detailed and calibrated modelling results from pilot injection projects can be matched with (semi-) analytical or simple 2D models that are less data intensive and require less numerically effort, the higher the confidence in providing an adequate modelling process that is time- and cost-effective.

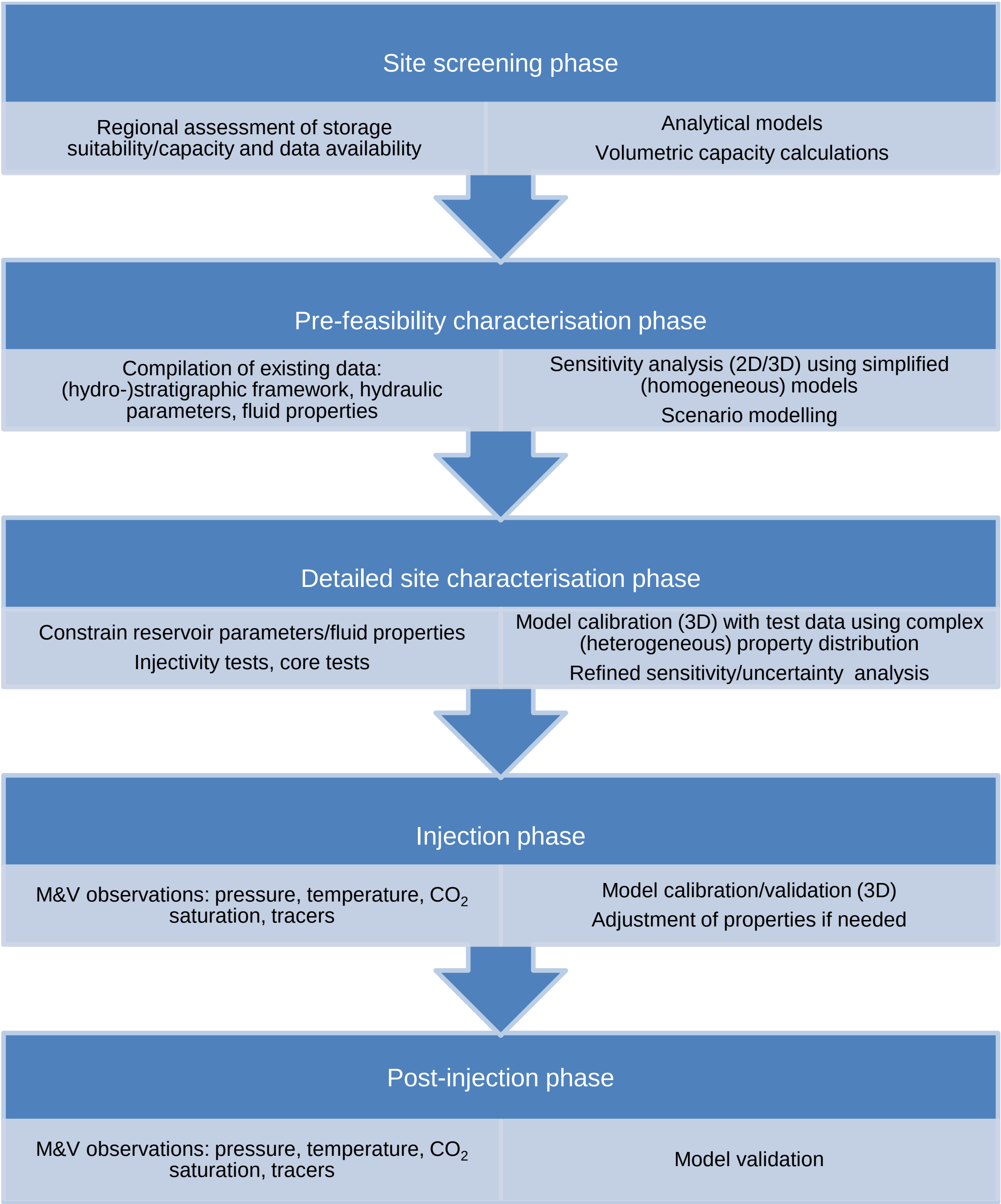


Figure 37– Generalised workflow for the reservoir simulation requirements during various phases of a CO_2 injection pilot project.

7.3. Monitoring of small-scale CO_2 injection tests

Monitoring is the third key step of the subsurface storage workflow for a high level CO_2 storage characterisation pathway of 1: static modelling, 2 flow modelling, 3 monitoring and verification. It is used primarily as the basis of assuring that undesired or unexpected events that are identified in the risk assessment of the project, and that the likelihood of them occurring is not increasing. The purpose of monitoring in CO_2 geological storage, in the strictest sense, is summarised as follows:

1. *"In order to ensure that geologic CO_2 storage is effective, monitoring of CO_2 storage sites will have to be carried out to verify that CO_2 is not leaking from the intended storage site, migrating to the near-surface environment, and seeping out of the ground." (Oldenburg et al, 2003).*

This form of monitoring, to assure that potential adverse events, recognised in the project risk assessment as being of high importance, relates to impacts on health safety and the environment. However, outside the realm of leakage surveillance, there are numerous other objectives in monitoring including:

- Pre injection monitoring for developing site baselines and adding to the data collation in site characterisation
- Varied assessment of the storage activity relative to performance targets and reporting requirements, providing modelling calibration and storage effectiveness guidance. These may include:
    - Assessing the accuracy of modelled predictions
    - Assessing the pore space utilisation
    - Accounting of injection volumes

In a commercial CCS project these points would form the basis of the monitoring program. However, for test injection activities, where R&D on monitoring technology may be a focus, knowledge of processes in the sub surface becomes vital, and can be extended to include understanding the performance and limitations of monitoring technologies in assessing these processes. Therefore monitoring in test injection projects may be used for a variety of purposes.

This may include monitoring (and benchmarking monitoring techniques) for:

- Spatial distribution of injected fluid or changes in fluid saturations,
- Geomechanical and structural events/changes to the subsurface
- Physical/chemical changes to injection interval and overburden
- Physical/chemical changes in the near-surface/surface/atmosphere

A high level example of the likely monitoring intervals that might be needed for a "typical" CO_2 test injection is provided in Figure 38.

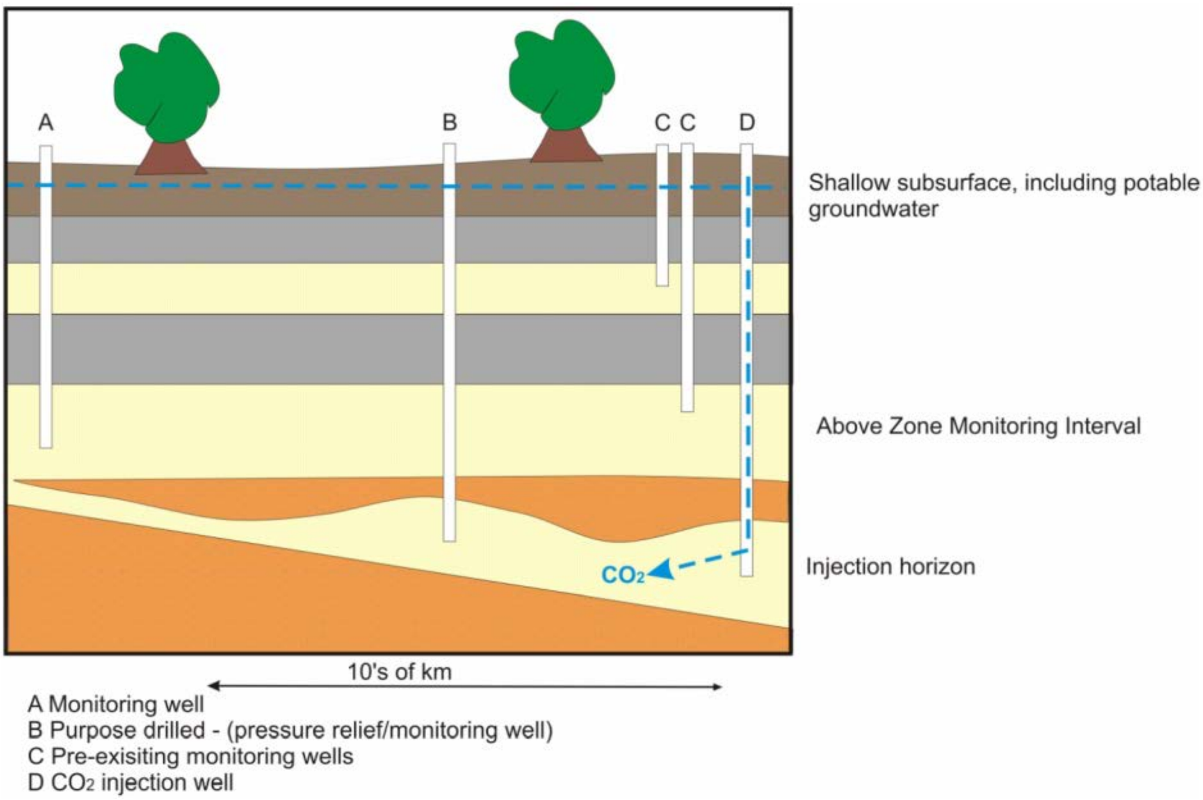


Figure 38 – Schematic of the monitoring intervals considered for evaluation of suitable tools for monitoring substances mobilised by CO_2. (from Stalker et al, 2011).

Baseline monitoring to establish natural variability should be undertaken as soon as the evaluation of the site commences and certainly well before injection of CO_2 is initiated. Project monitoring should take place as soon as changes are made in the subsurface, typically associated with the start of injection of CO_2. In the case of EOR or ECBM, project monitoring may start with the production of hydrocarbon rather than the start of fluid injection. However, there are many considerations required in developing effective monitoring operations and the planning for monitoring ideally should start no later than early within the evaluation stages of a CO_2 storage project (Figure 39). For many of the test injection projects, the planning for monitoring commences at the very onset of the opportunity definition, as a key purpose of a test project typically includes R&D into monitoring technologies. Field trials of the effectiveness of particular monitoring techniques falls within the evaluation stage, so that findings (including realised technology restrictions), can be considered in the more mature monitoring plan. When projects require monitoring of the biosphere, seasonal variability and related factors typically require long term biosphere characterisation, which needs to start at the start of the “Define” stage (Figure 39). The commencement of the project build phase typically coincides with the deployment of the majority of the monitoring infrastructure (such as dedicated observation wells) and the commencement of baseline monitoring (such as initial 4D seismic). Monitoring of the performance of the CO_2 injection will typically extend beyond the conclusion of CO_2 injection, with the time depending on the requirements of the regulator and match between modelling and monitoring results. Assurance monitoring is likely to continue through to near the end of the closure of the project, again depending on regulatory requirements. In some circumstances assurance monitoring maybe continued by the regulator or some designated body, post closure.

Figure 39 – High level monitoring activities during the development and execution of a test injection project.

There are many examples of CO_2 storage projects deploying a range of monitoring techniques and these are outlined in the project data sheets (Appendix 2). An example list is provided below (source: IEAGHG CO_2 Monitoring Technique Database). This list has been adopted here, but this Report does not aim to consider the individual application of all techniques.

- 2D surface seismic
- Airborne EM
- Boomer/Sparker profiling
- Bubble stream detection
- Cross-hole ERT
- Downhole fluid chemistry
- Ecosystems studies
- Electric Spontaneous Potential
- Geophysical logs
- High resolution acoustic imaging
- Land EM
- Long-term downhole pH
- Multibeam echo sounding
- Non dispersive IR gas analysers
- Seabottom EM
- Seawater chemistry
- Single well EM
- Surface gas flux
- Tiltmeters
- Vertical seismic profiling (VSP)
- 3D surface seismic
- Airborne spectral imaging
- Bubble stream chemistry
- Cross-hole EM
- Cross-hole seismic
- Downhole pressure/temperature
- Eddy covariance
- Fluid geochemistry
- Ground penetrating radar
- IR diode lasers
- Land ERT
- Microseismic monitoring
- Multicomponent surface seismic
- Satellite interferometry
- Seabottom gas sampling
- Sidescan sonar
- Soil gas concentrations
- Surface gravimetry
- Tracers
- Well gravimetry

There are trends in the adoption of certain monitoring techniques for test injection projects captured in the database (Appendix 1). Test injection activity was separated by storage types, because the needs of the monitoring program were found to differ according to storage type. Four cases are outlined below which serve to showcase a potential monitoring program relative for each of the storage types. However, it is important to note that a monitoring program will need to always be developed specific to the storage site, economics, project needs and project goals. No monitoring precedent is implied from these four cases, no technologies are recommended as always included or excluded, and the ideal monitoring solution will always be unique to a project.

General trends in the test injection monitoring are as follows:

- Subsurface pressure measurements were performed in nearly all projects, providing assurance that pressures were not approaching undesirable levels and data for the history matching of plume simulations (Figure 40). Pressure measurements appear to be a fundamental requirement of any CCS monitoring system. Pressure transients occur ahead of the migrating CO_2 plume potentially allowing the detection of changes some distance away from the source of CO_2. This increases the coverage of the individual components (i.e. wells) of the monitoring system and increases the likelihood of early detection and remediation of any unanticipated events. Subsurface temperature measurements were also commonly taken (Figure 41), perhaps in part as a consequence of the pressure tool also having the capability to record this data – in other words there was little or no extra cost incurred in collecting potentially useful temperature data.

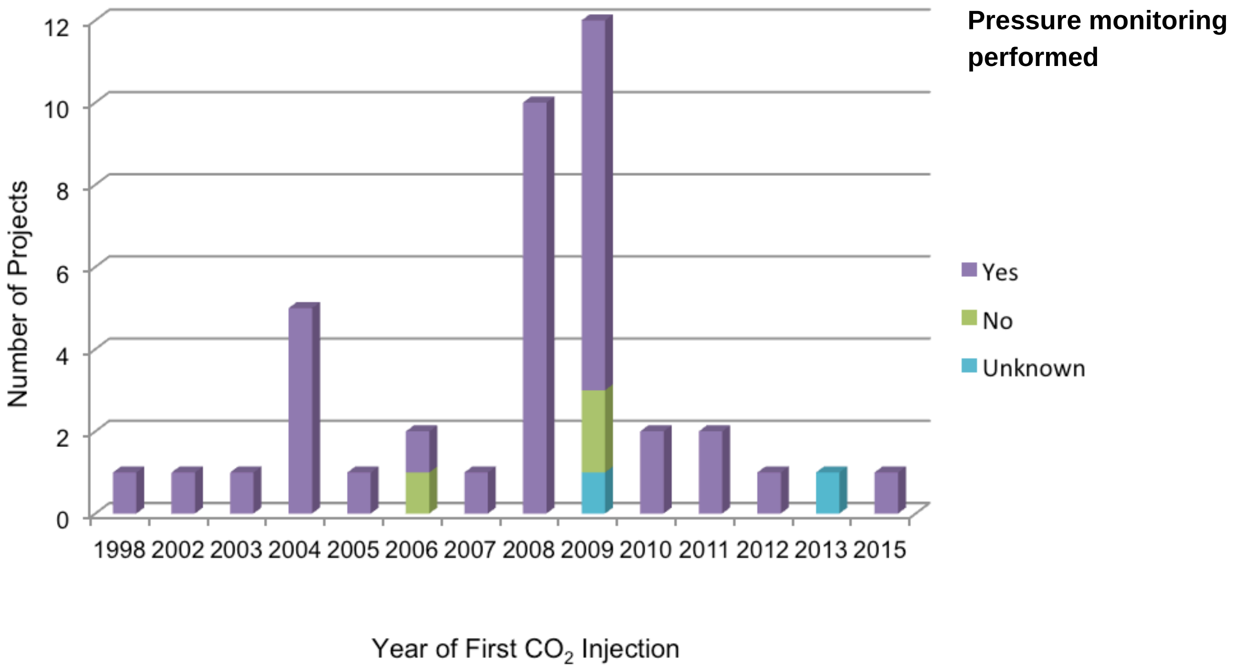


Figure 40 – Pressure monitoring for test injection project monitoring.

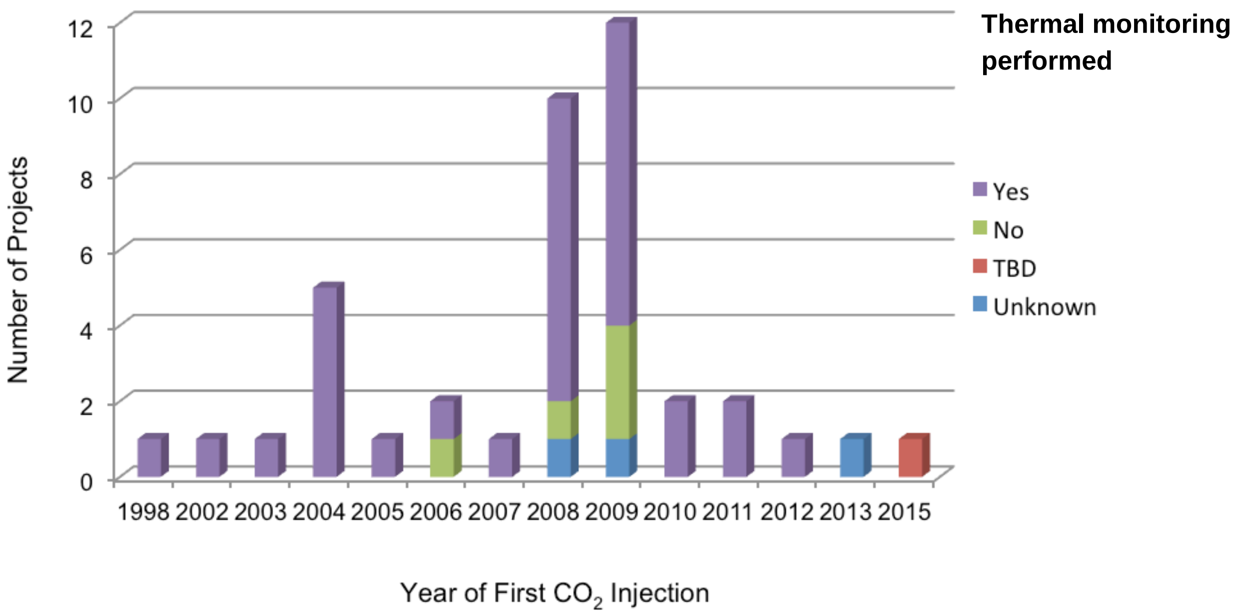


Figure 41 – Thermal monitoring for test injection project monitoring.

Over half of the projects use one or more dedicated observation wells to assist in the monitoring of CO_2 storage (Figure 42). In a quarter of cases more than one observation well is used. Wireline logging of wells associated with the injection projects appears to increase over time, with the majority of projects operating post 2007, applying this monitoring technique (Figure 43). Geochemical monitoring/fluid sampling of the subsurface, while a difficult and costly monitoring practice, has also been a common direct method of measuring changes in the subsurface during a project (Figure 44). Direct sampling methods such as U-tube sampling have provided very useful information on the processes of fluid flow and chemical changes in the reservoir. The extent of logging and geochemical monitoring varies depending to some extent on whether it is undertaken in observation wells or injection wells.

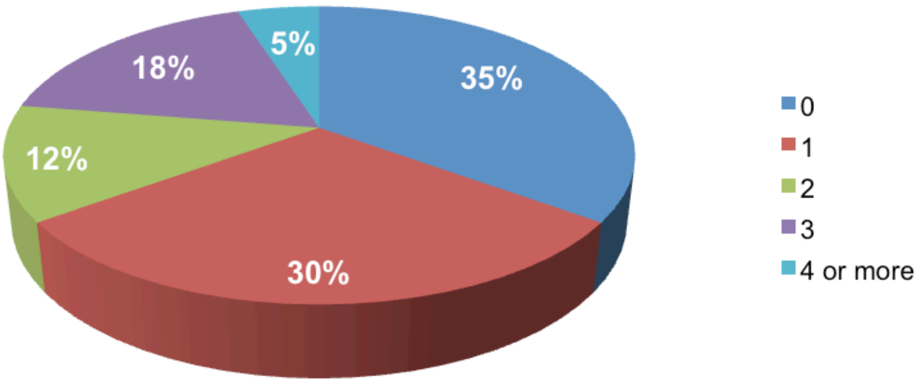


Figure 42 – Number of dedicated observations wells drilled for the test injection project monitoring.

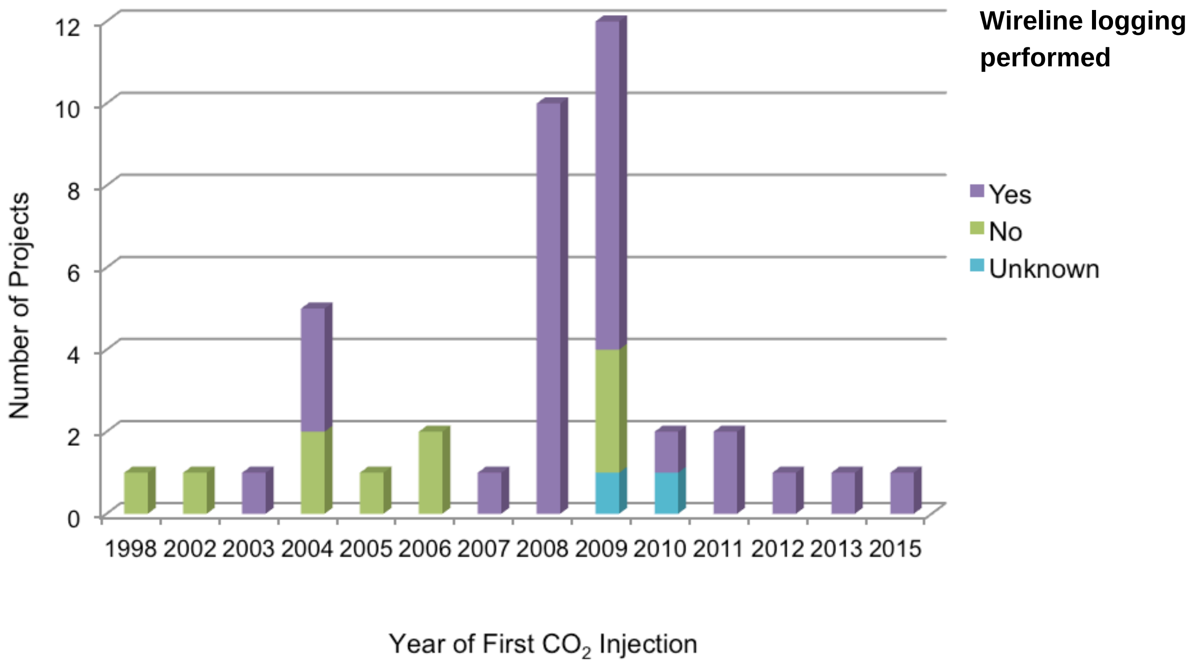


Figure 43 – Wireline logging for test injection project monitoring.

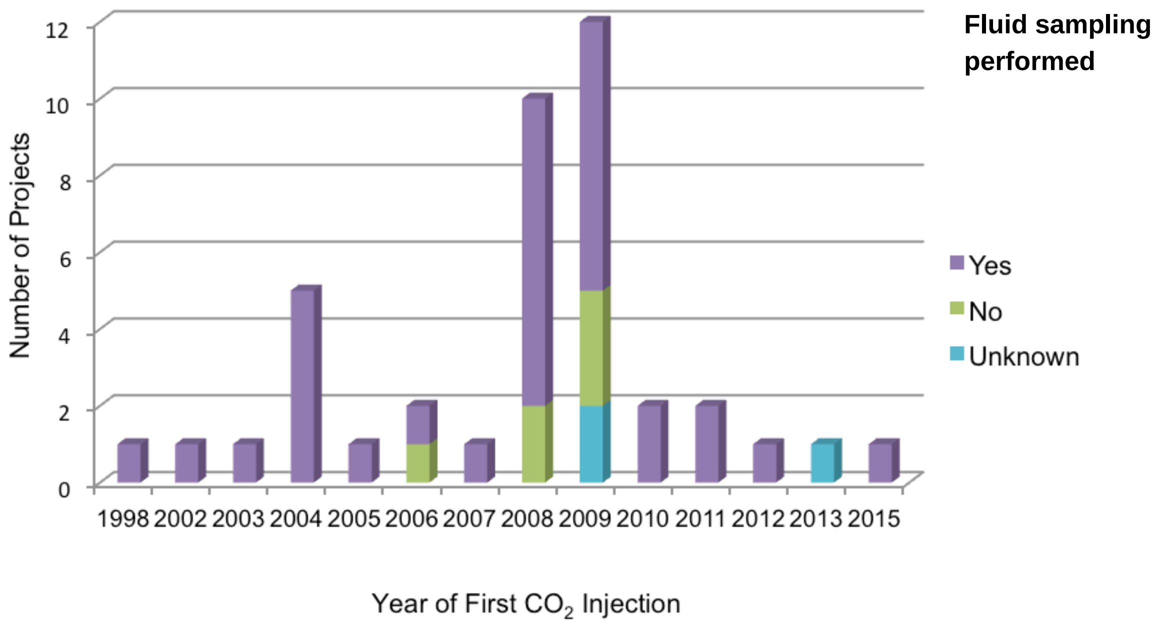


Figure 44 – Geochemical and/or fluid sampling for test injection project monitoring.

Active seismic monitoring is performed either through borehole and/or surface seismic acquisition in more than half of the test injection projects (Figure 45). Trends in monitoring relative to the storage type is most apparent in seismic monitoring, with deep saline aquifer storage preferentially adopting seismic monitoring, while storage types with an existing understanding of the subsurface geology such as EOR projects and/or those with a stronger geochemical monitoring program, less likely to undertake seismic monitoring (Figure 46). New seismic monitoring is appropriately used in test injection projects where other data is sparse. Both borehole and surface seismic is used (Table 3) as a core monitoring tool in many projects. 4D seismic is a very mature technology, highly valued for CO_2 monitoring as it provides a geospatial distribrution of the plume. However, it is commonly a high cost technology and is not always a suitable, particularly for onshore and nearshore projects due to seasonal variations in ground surface conditions (repeatability issues) and wave noise. Also, the small volumes of CO_2 associated with small scale projects can result in plumes being below seismic detection limits. Interestingly other geophysical techniques such as electromagnetic and gravity have been rarely tested in this project set. 4D seismic, being a mature, proven technology from the oil and gas industry, offers the potential to benchmark these and other less used monitoring techniques, which may have validity in CCS.

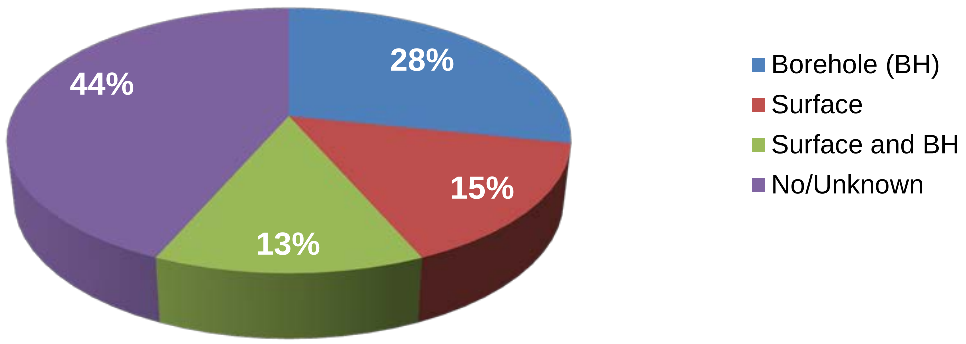


Figure 45 – Ratio of active seismic monitoring types used in the test injection projects.

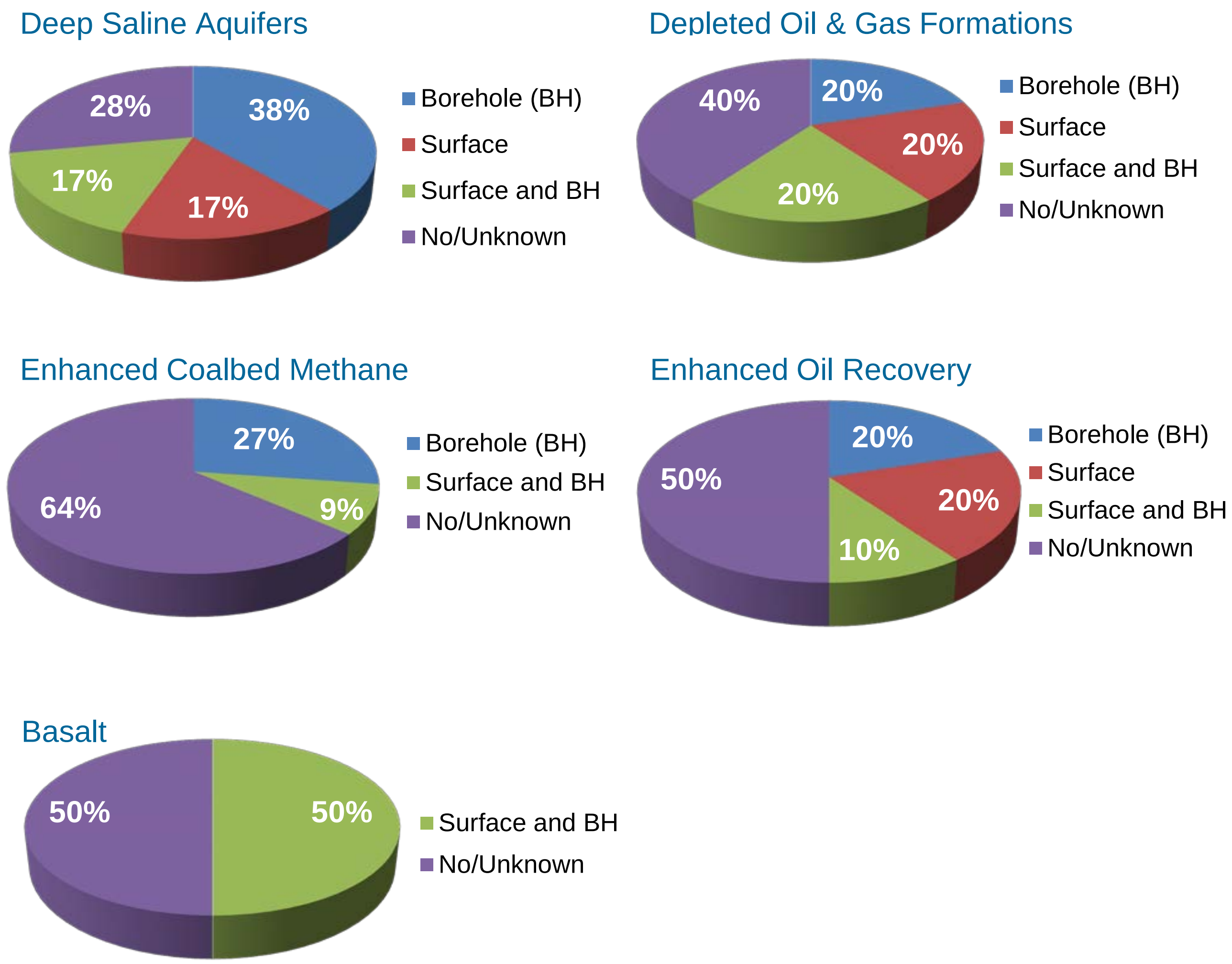


Figure 46 – Test injection projects utilising active seismic monitoring classified by storage type.

Table 3 – Various active seismic monitoring techniques applied to the test injection projects. Projects are classified by storage type to understand trends in monitoring types selected.

Storage Type	Active Seismic Monitoring								
	No/ unknown	Surface 2D	Surface 3D	Surface 4D	All with Surface Seismic	VSP	Cross-well	All with Borehole Seismic	All with both BH and Surface Seismic
All Projects	43% 20	13% 6	20% 9	7% 3	28% 13	35% 16	24% 11	41% 19	13% 6
Deep Saline Aquifers	28% 5	22% 4	22% 4	6% 1	33% 6	44% 8	33% 6	56% 10	17% 3
Depleted Oil & Gas Formations	40% 2	0% 0	20% 1	20% 1	40% 2	40% 2	20% 1	40% 2	20% 1
Enhanced Coal Bed Methane	64% 7	0%	9% 1	0%	9% 1	18% 2	18% 2	27% 3	0% 0
Enhanced Oil Recovery	50% 5	10% 1	20% 2	10% 1	30% 3	40% 4	20% 2	40% 4	20% 2
Basalt	50% 1	50% 1	50% 1	0% 0	50% 1	0% 0	0% 0	0% 0	0% 0

7.3.1. Deep Saline Aquifer Monitoring

Monitoring in deep saline formations focuses on observing the geospatial distribution of the CO_2 plume. A majority of the projects adopted geophysical sensing tools, with the primary geophysical monitoring type being seismic (surface seismic, borehole seismic or both; Figure 46). In most cases this technology was used for confirming modelled predictions and assuring plume distribution within the storage container. Somewhat novel seismic configurations as outlined in the case studies below, have been adopted in attempts to improve the resolution of the injected plume and/or to accommodate the restrictions of the existing well locations. As previously noted, other geophysical monitoring tools such as gravity and electromagnetic, appear to have had very limited testing, perhaps because they are less mature technologies and/or the primary objective of the test injection was not associated with tool testing.

Observation wells are commonly used in injection tests to assist in understanding the plume's fluid flow processes. In nearly all cases, pressure and temperature monitoring was used, and in most, there is a comprehensive geochemical/fluid sampling program.

Ketzin Case Study

The Ketzin test injection is an excellent example of a project with a primary focus on geophysical, geochemical and microbiological monitoring methods, to understand subsurface processes and to test the capabilities of monitoring tools to characterise these processes. Ketzin uses a wide range of physical, chemical and biological monitoring technologies to characterise a saline formation where CO_2 is injected in both sub- and supercritical gaseous phases in a gaseous phase (i.e. not supercritical). This monitoring activity provides practical experience in the monitoring and testing of different models that predict plume migration, and for determining what technologies are required to verify long term storage. For a detailed description of the Ketzin installations and operational monitoring program refer to Liebscher et. al., 2013.

Injection test set-up can be separated into direct borehole, seismic (borehole and surface), and physical sampling. A summary of this monitoring arrangement is provided in Figure 47. The two monitoring wells involve smart casing completions including Distributed Temperature Sensing (DST) fibre optics, and Electrical Resistivity Tomography (ERT) electrodes, while the injection well utilised a fibre optic pressure and temperature sensor for direct measurements of the plume character. Bottom Hole Pressure and temperature and well head pressure were also monitored.

Seismic receivers (and a source) were deployed in the observation wells for Moving Source Profiling (MSP), Vertical Seismic Profiling (VSP) and Crosswell seismic. Surface 2D and 3D seismic and a 'Star' experimental configuration were also deployed.

A Gas Membrane Sensor (GMS) was deployed in the monitoring well for sampling of formation fluids. A pre-injection tracer slug of flurobenzoic acid, naphthalenedisulfonic acid and KCl, followed by Krypton tracer was used to assist the chemical characterisation of the changing formation fluid.

This broad range of technologies allowed comprehensive monitoring of the plume in 3D space as it moved towards and beyond the two observations wells. Ketzin's comprehensive geophysical and geochemical monitoring configuration provides the opportunity to independently test different simulation models and to better constrain reservoir and fluid behaviour during and after CO_2 injection.

In addition to the configuration for monitoring of the plume in 3D space, an extensive logging program was undertaken to assess well integrity. This was done using pressure–temperature measurements, Reservoir Saturation Tool (RST), Cement Bond Logs (CBL), Ultra Sonic Imaging (USIT) and Magnetic Inductive Defectoscopy (MID) measurements. Video inspections of the observation wells also took place.

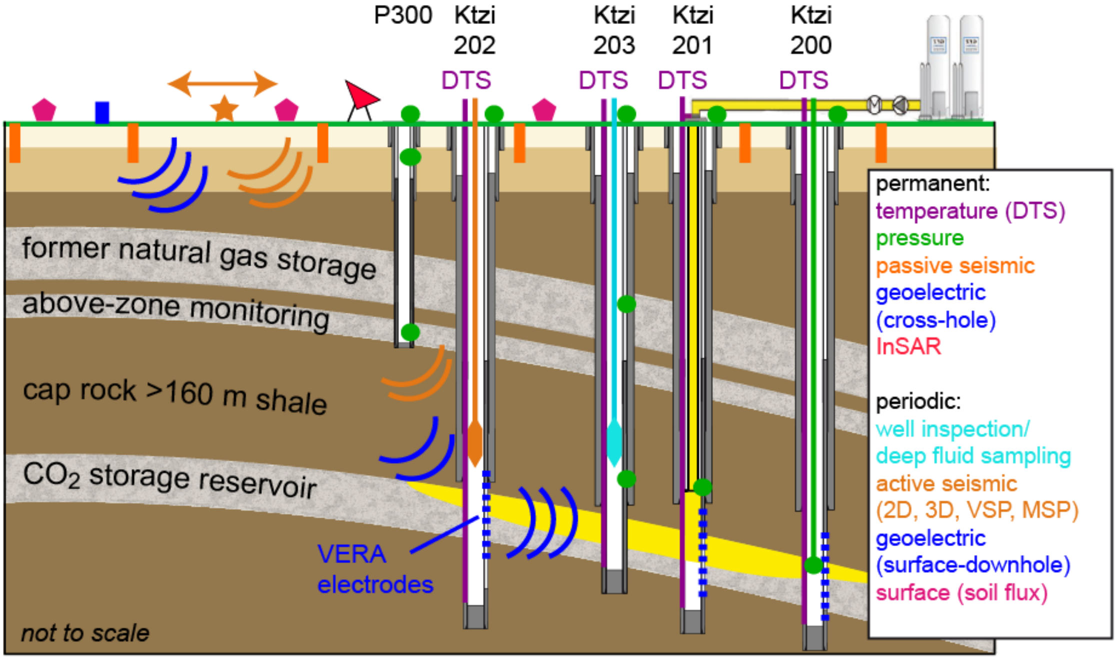


Figure 47 – Monitoring configuration at Ketzin (Figure courtesy Liebscher)

7.3.2. Depleted Oil and Gas Fields

Monitoring trends from storage depleted oil and gas reservoirs were difficult to discern, given due the limited number of projects in this storage type (four). A reasonable expectation for monitoring of test projects in depleted oil and gas reservoirs is that there will be reduced interest in monitoring for geospatial distribution as the geological structure is typically well understood. Additionally the presence of residual methane makes it difficult to detect small CO_2 plumes using seismic techniques. This expectation is evident in Figure 46 relative to active seismic monitoring. A stronger focus is apparent in geochemical monitoring, with tracers commonly incorporated into the injection, together with monitoring through subsurface well sampling; or shallow aquifer, soil gas and atmospheric sampling. Downhole pressure and other physical measurements are a feature of DOGF projects because of their value to understanding the change in the reservoir throughout the injection process.

Otway Stage 1 Case Study

The CO2CRC Otway Project Stage 1 was a demonstration of mid-scale storage (65,000 tonnes of CO_2) within a depleted gas field. The monitoring program for this experiment, developed in conjunction with regulatory authorities, aimed to confirm containment of injected CO_2 in the reservoir, supply data to relate to modelled prediction accuracy, and provide assurance that groundwater, soil and air were unaffected (Dodds et al., 2009). Validation that the plume is contained within the reservoir came from log based measurement which showed no evidence of CO_2 above the secondary container. In addition, key performance indicators were established/tested, showing no evidence for the injected CO_2 within groundwater, soil or atmosphere.

The project ran a comprehensive monitoring program, with baseline measurement commencing in 2006 (one year before the commencement of injection) through to the present. There was significant research using petroleum exploration tools and information, in order to establish baseline information, including wireline logging, VSP, and other seismic surveys prior to commencing the project. The monitoring well is a former gas production well (Naylor-1). The gas injected is an approximate 80:20 mol % mix of CO_2 and CH_4 from a nearby gas field (Buttress-1). Baseline monitoring consisted of soil gas surveys, ground water surveys, seismic and atmospheric surveys. There is still ongoing post-injection monitoring and verification surveys, providing assurance that there has been no change to these systems associated with CO_2 storage.

The bottom-hole assembly deployed in Naylor-1 included geophones for VSP and micro-seismic imaging. Many of these failed shortly after deployment, as did the pressure and temperature sensors. These difficulties are thought to be due to the utilisation of the pre-existing production well that was both narrow and contained a casing patch at a critical depth close to the injection formation. A downhole gauge monitored temperature and injection pressure in CRC-1 while surface pressures were available from Naylor-1, which were corrected to reservoir pressures. A backup micro-seismic system was installed in a shallow water well close the Naylor-1. The U-tube sampling system was also part of the bottom-hole assembly.

U-tube sampling at three different depths in the Naylor-1 monitoring well, allowed the determination the timing of CO_2 (and tracers: deuterated methane, Kr and SF_6) breakthrough and passage downward as a moving gas-water contact (Figure 48). Predictive models were validated by a comparison with the measured molecular, isotopic and tracer compositions. Direct sampling continues to assure longer term containment.

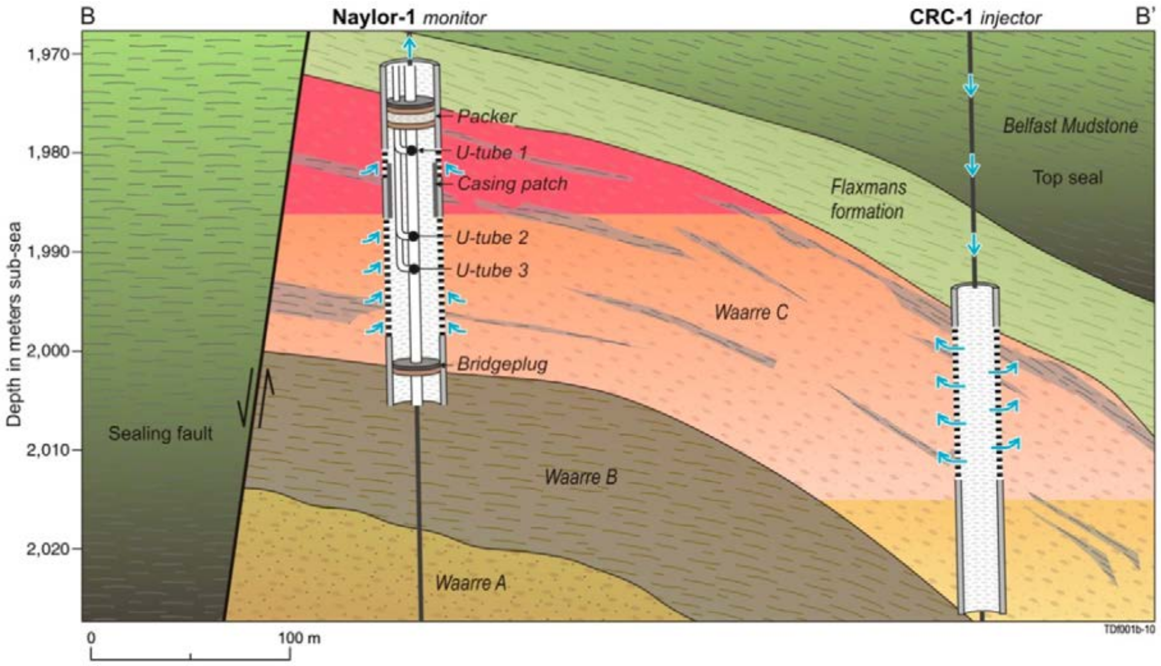


Figure 48 – Schematic of the injection and monitoring wells, indicating wellbore perforations and U-tube inlets. The red zone was the remaining CH_4 gas cap pre-injection, while the light orange zone was the residually trapped CH_4 (Jenkins et al, 2011)

7.3.3. Enhanced Oil Recovery

A clear monitoring focus in EOR is the measurement of produced fluid to assess the effectiveness of the enhanced recovery process. In all cases the producer wells were used as the mode to geochemically sample the fluids. Existing tracers in the oil phase were utilised to quantify the effectiveness of the EOR process. Additional wireline monitoring was also commonly used (often via cased holes), along with pressure and temperature monitoring.

Monitoring efforts in terms of plume distribution is seldom a major feature of the EOR monitoring regime, as the geology of the system is typically well understood. Borehole seismic is used to determine the effectiveness of the EOR process.

<u>CO_2-EOR Pembina Cardium case study</u>

The CO_2-EOR Pembina Cardium CO_2 Monitoring Pilot consisted of two CO_2 injectors and six producers which intersected all four units (conglomerate, upper sandstone, middle sandstone, and lower sandstone) in the 20 m thick Cardium Formation (Hitchon, 2009). Monitoring the migration of CO_2 in the Cardium reservoir was assessed through the use of seismic imaging, pressure and temperature measurements, and produced-fluid analysis within and external to the Cardium reservoir.

The project constructed and deployed instrumentation strings with three pairs of downhole pressure-temperature sensors, eight geophones, and two downhole fluid recovery ports. In-situ tracers sensitive to water mixing, and rapid reactions between minerals and the injected CO_2, allowed early detection of CO_2 breakthrough, and provided additional constraints for history matching by reservoir simulators.

A permanent geophone array in the observation well allowed Vertical Seismic Profiles (VSPs) to be used for monitoring the CO_2 plume within the Cardium reservoir, and was able to detect the CO_2 plume migration over a small volume around the well. Atmospheric monitoring using a tunable diode laser system, and groundwater monitoring using dedicated shallow wells, were deployed for assurance monitoring. No leakage of the CO_2 to surface was detected.

Reservoir simulators were an important part of the project. Existing pre-pilot and pilot data were successfully history matched with the ECLIPSE compositional model (E-300). However, future predictions of the magnitude of the oil production from CO_2-EOR appeared anomalous. These results may need to be verified by using a different reservoir simulator such as the GEM compositional model of the Computer Modelling Group; benchmarking of several reservoir simulators against each other would be useful in evaluation of storage sites, in order to reduce uncertainties.

7.3.4. Enhanced Coal Bed Methane

As in EOR, monitoring in ECBM focuses on the measurement of produced fluid to assess the effectiveness of the enhanced recovery process. Producer / observation wells, positioned normal to the coal's face or butt cleats, sampled the fluids for geochemical analysis and to understand fluid flow properties. Interestingly, added tracers were not commonly used, with projects relying instead on existing components in the injectant or analysing for components in the released methane. Surface seismic is very rarely used in the ECBM test injections. Borehole seismic is more commonly deployed, to understand the effectiveness of the ECBM process.

MGSC ECBM case study

The aim of the MGSC ECBM project was to deploy and test the capabilities of a few monitoring techniques, and use those techniques to detect any significant CO_2 leakage events, should they occur. The project consisted of four wells; one injection well and three monitoring wells (Figure 49). Two existing shallow wells were used along with additional shallow groundwater wells to monitor ground water.

The monitoring, verification and accounting program was set up to detect CO_2 leakage and assess the injection performance. Atmospheric CO_2 levels were monitored, as were indirect indicators of CO_2 leakage such as plant stress (CIR imagery), changes in gas composition at well heads, and changes in several shallow groundwater characteristics (e.g. alkalinity, pH, oxygen content, dissolved solids, mineral saturation indices, and isotopic distributions). Baseline, injection and post injection monitoring included in-zone pressure and temperature, gas content within the injection formation and cased hole logging was also performed.

Results showed that there was no detected CO_2 leakage into groundwater or to the surface. Post-injection cased hole log analyses supported this conclusion.

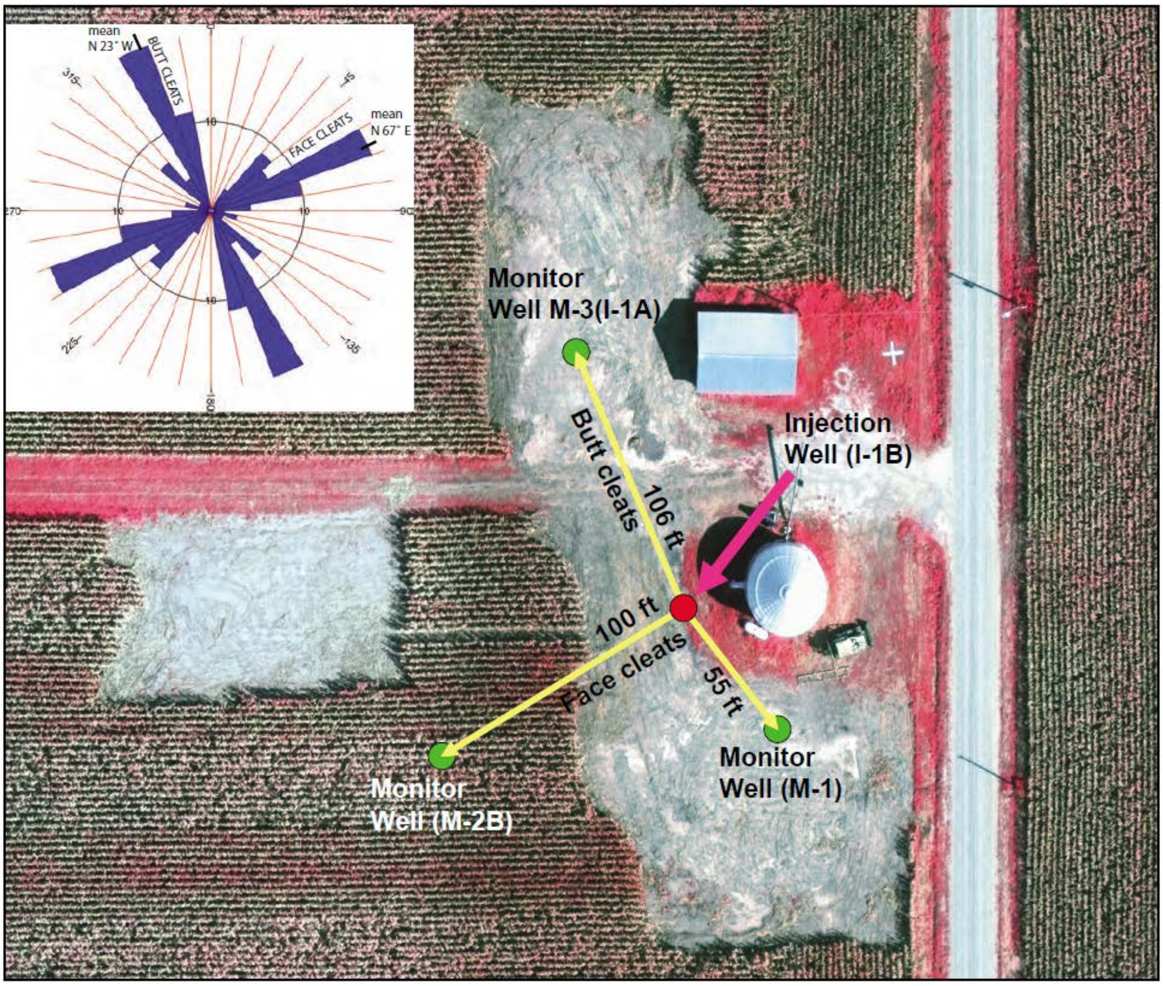


Figure 49 – Monitoring configuration at MGSC ECBM.

7.4. Containment risk assessment in small-scale CO_2 injection tests

Documentation of storage risk assessment for test injection projects, was very limited despite its perceived importance by regulators and other key stakeholders importance. For the consideration of risk in test injection projects therefore a case example has been selected to demonstrate a risk assessment case study. This case is the Otway Pilot Project Stage 1. Further information on the Otway Stage 1 can be found in Jenkins et al., 2011.

7.4.1. Otway Project case study of risk assessment

A key objective of the Otway storage project was the demonstration of safe and effective underground storage of CO_2. The achievability of such containment was assessed via risk and uncertainty analysis, which considered the occurrence of unlikely events inducing leakage. Due to the nature of subsurface leakage, a specific risk analysis technique was applied to containment risk. This assessment strongly relied on the characterisation of the subsurface, fluid flow and understanding of the changes resulting from the injection. The resulting risk assessment was used to determine a risk mitigation and monitoring program required to assure CO_2 containment.

The project utilised its own risk assessment research within the CO2CRC in combination with the generic proprietary risk assessment method RISQUE (Bowden et al., 2001, Bowden & Rigg, 2004). While CCS was considered a new application of RISQUE, importantly the tool and methodology still met the industry standard of risk assessment, and was kept very transparent in its application. The development of the risk assessment and associated risk management was tied to the project development as shown in Figure 50.

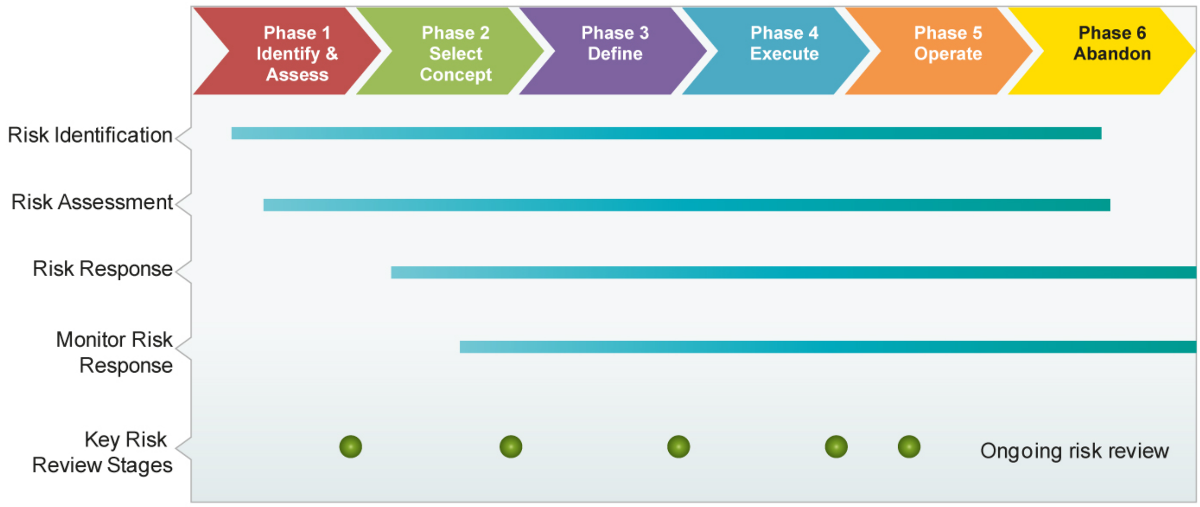


Figure 50 – High level risk assessment processes during the development and execution of a test injection project.

7.4.2. Methodology

The assessment of storage risk involved an understanding of uncertainty in the subsurface storage complex. This uncertainty is normally quite broad at the start of any subsurface project, and should never be expected to be fully resolved. Firstly, the mechanisms that may provide conduits for CO_2 leakage are characterised. For the Otway Project, these included the top seal, the bounding faults, 2 wells, and the lateral bounds of the storage complex. Statically, these mechanisms will hold thresholds before a leakage event would initiate. These thresholds, including its inherent uncertainty, were determined. Secondly, the changes caused by CO_2 injection and storage (including changes in pressure, temperature, stress or chemistry) were modelled. These changes can possibly lead to CO_2 leakage through processes such as faults reactivation, caprock fracturing, chemical erosion of wellbore or caprock; and other storage related events such as induced seismicity and ground deformation. Understanding the range of static properties and associated uncertainties, and then comparing this to the modelled dynamic changes involved in the subsurface due to CO_2 injection (which also have uncertainty), is key to any containment risk assessment both in large scale and test injection projects.

Risk in the RISQUE method used in the Otway Project, is defined simply as the relationship between the likelihood of an individual risk event, and the impact of a risk event (in this case, CO_2 leakage) along an identified pathway. Facilitated expert workshops, with all interpreted data and models discussed and uncertainty considered, enabled rational consideration of risk with discipline-specific experts. To add quantification to the assessment a project team aspired to have leakage at less than the likely retention defined in the IPCC on CCS (IPCC, 2005). From this an acceptable limit can be set (at 1% total leakage over 1,000 years for the Otway example). This risk assessment technique considered leakage of CO_2 outside of the defined storage complex as the risk impact. It did not assess the consequence of a leakage event, which was instead assessed using large scale modelling of leakage paths. It was considered that any injection project should also establish what style of CO_2 leakage (in terms of volume and rate minimum thresholds) would have a material impact on a particular medium (i.e. environment, human health and safely, and natural resources) and also take a more holistic view of risk in terms of financial and social/political risk.

7.4.3. Risk Assessment Context

To frame an assessment of a given risk event, the exact context of the project activity regarding storage must be clearly stated. As a project evolves this context needs to be adjusted to best match the project operation plan. The example project context from the Otway Project for the risk assessment was described as:

- CO_2 sourced from the nearby CO_2-rich gas field and transported via pipeline to the injection point (CRC-1) located east and down-dip from the depleted Naylor gas field
- injection volume of 3mmscf/d for a period of 2 years for a total of 100,000 t stored
- CRC-1 injector located approximately 300 m from the crest of the structure. Existing Naylor-1 well used as the observation well.

7.4.4. Storage Complex

The storage complex of the project also needed to be clearly described, so that it is clear how leakage could occur within the risk assessment context. For the Otway Project the storage complex is the ~30 m thick Mid Cretaceous Waarre Sandstone Unit C reservoir, which occurs at a depth of approximately 2000 m. It was modelled that the CO_2 would migrate up-dip into the crest of the structure. The sandstone is overlain by a series of mudstone up to 500 m thick including the Flaxmans Formation; the Late Cretaceous Belfast Mudstone; and the Skull Creek Formation. The storage complex for the Otway project is defined as the entire tenement block below the top of the seal. Overlying the seal is the secondary reservoir, which is then overlain by the Late Cretaceous Timboon Sandstone, which is the deepest potable water aquifer of the region.

7.4.5. Risk Items

A risk assessment needs to consider the aspects of the leakage mechanisms or changes to the storage complex due to CO_2 injection, which may increase the chance of leakage. Two risk item examples from the Otway Project's risk assessment have been taken and summarised below:

Leakage from Permeable Zones in Seals

In characterising the seal quality of the primary regional seal (~500 m thick mudstone caprock), factors that were taken into account included the high degree of well control, firm seismic evidence of lateral continuity, excellent seal quality, as well as understanding that CO_2 has the additional barrier of the overlying lower permeability reservoir. Seal capillary analysis determined that the maximum modelled gas column (~30 m) below the seal was an order of magnitude less than what would be required for buoyancy pressure to overcome the capillary pressure at the wells (lowest seal capacity result determined at 303 m; Daniel 2007). The seal interpretation was extrapolated across the whole caprock for the storage area. Therefore, this risk refers to the possibility that there was a substantial decrease in the seal quality away from the wells, due to seal heterogeneity providing a pathway for CO_2 leakage. This included the potential for existing fracture-based or other intrusion-based pathways with sufficiently high permeability for leakage, or CO_2 reactions with the seal lithology, resulting in the creation of a leakage pathway through the seal.

Leakage from Faults

Assessment of this risk event relies on an ability to identify faults from seismic data, in particular, to establish whether it is likely that the faults have:

- Insufficient throw to create a clay smear seal and/or a lack of a direct juxtaposition to the overlying mudstone, which would prevent across fault leakage and;
- Sufficient fault length to consider along flow leakage out of the storage complex.

For the structure the Naylor, Naylor East (at the junction to Naylor fault), and Naylor South faults were all considered as potential pathways for leakage from faults to the secondary reservoir (Figure 51). Dynamic modelling showed that CO_2 would presumably initially migrate to the Naylor fault, relying on the fault seal to the west and, as the CO_2 continued to accumulate, also relying on the fault junction seal between the Naylor and Naylor East faults. The Naylor South fault was included to capture the risk of leakage in the event that some of the CO_2 plume migrated around the spill point of the initial Naylor structure into the greater structure.

CO_2 was modelled to accumulate against the Naylor fault and the Naylor East fault at the junction with the Naylor fault. A juxtaposition seal is required for these faults at the injection/storage interval. The Naylor fault and Naylor East fault were interpreted to have a strong across-fault seal as they are juxtaposed against Belfast Mudstone at the injection interval for the storage structure. Hence the chance of across fault flow out of the storage complex was regarded as zero.

Where faults were of sufficient length to cut the storage complex, the geomechanical properties of the faults needed to be considered, in the context of the likelihood of connected fracture conduits along the fault plane. Leakage via fault reactivation as a result of enhanced natural or anthropogenic mechanisms was handled separately (below).

The Naylor fault extends vertically through the ~500m top seal. Fault reactivation modelling suggested that this fault was orientated and stressed in a manner that increased the likelihood of reactivation occurring; work by Lyon et al., (2005), this suggests it may allow along-fault leakage. The Naylor East fault was interpreted to not extend vertically to the secondary reservoir. However the junction of this fault to the Naylor fault was of concern to the project team and judged to have a higher potential than the Naylor fault itself allowing along-fault leakage, to the full vertical extent of the fault and then potentially following the Naylor fault out of the storage complex.

As the Naylor fault and its junction with the Naylor East fault have been shown to potentially allow along-fault flow out of the primary container, an empirical analysis was performed to gather evidence on potential fault leakage. This analysis was based on an evaluation of 3D seismic to assess if there was any evidence that could be attributed to previous gas migration, including hydrocarbon related diagenetic zones (HRDZs), or gas chimneys. No features relating to gas migration were detected above the Naylor structure or in the region of the experiment. This was consistent with the lack of pressure communication between the injection interval and secondary reservoir determined from drilling of CRC-1 and the hydrodynamic evaluation of the area (Hennig, 2007). No gas shows were seen in the secondary reservoir and only trace gas (7 – 20 ppm) readings were recorded from the cuttings (CRC-1 Well Completion Report, 2007). Thus, even with the new data there was no evidence of vertical hydrocarbon loss via a fault conduit for the Naylor fault or fault junction.

The Naylor South fault was interpreted to have a strong across fault seal as it was juxtaposed against seal at the injection interval for the greater structure. This fault extends through to shallower potable water aquifers and aquitards and has been interpreted to have leaked hydrocarbons in the past, as shown by the presence of a palaeo gas column. This fault is optimally orientated for reactivation and is therefore considered to be a potential conduit for CO_2 flow. However, there was considered to a low chance of this happening (as determined through modelling), or that any of the CO_2 injected would reach this fault, as it was outside of the primary storage structure.

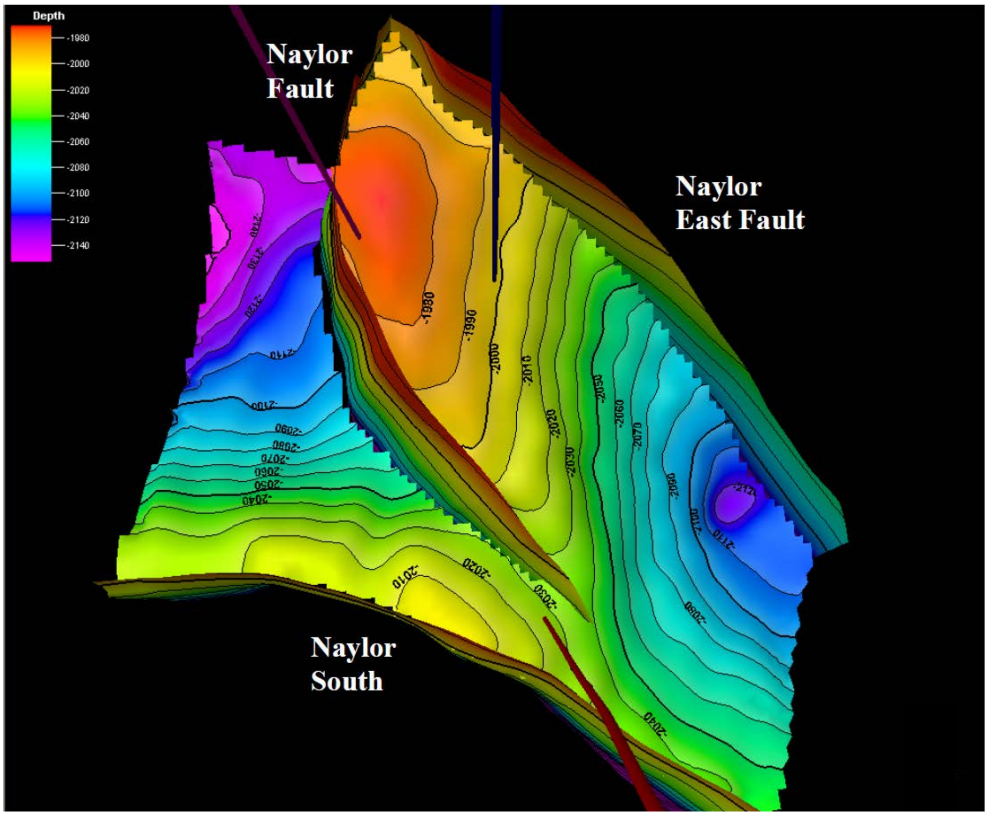


Figure 51 – Location of the three faults investigated in the greater Naylor structure (Dance, 2013).

7.4.6. Risk Assessment Output

A risk assessment output was used as part of the decision-support package for the project's final approval and in order to develop / refine the monitoring plan. A clear illustration of risk was therefore required in effectively communicating containment risk for the project. The risk output for the Otway project is shown in Figure 52. In this case, risk is described as a risk quotient (y-axis) normalised against the acceptable project containment risk (red dashed line). The risk quotient is derived by multiplying risk impact, in terms of leakage volume out of the defined storage complex, by the risk likelihood and number of risk items for that risk. This number is then normalised to the acceptable risk threshold so that cross project risk quotients can be compared. A risk quotient is derived for three confidence levels (pessimistic, planning and optimistic) for managing the variable risk appetites of the project stakeholders and decision makers.

In the Otway Stage 1 Project, no containment risk was found to be at an unacceptable level from this risk assessment.

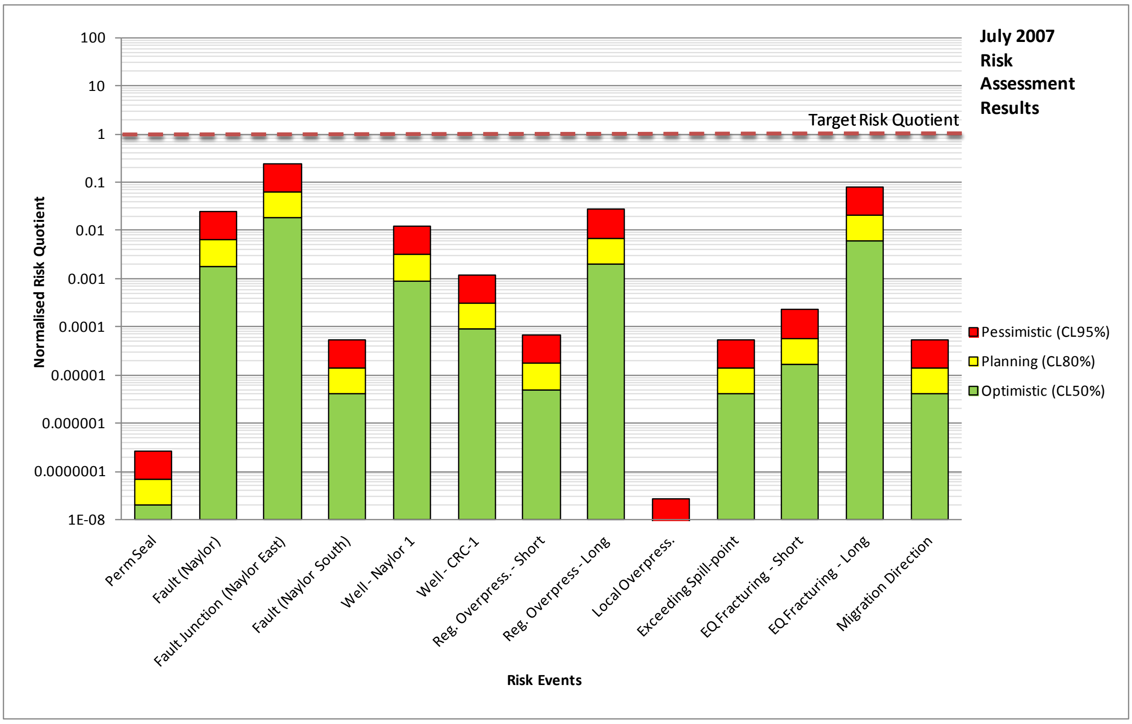


Figure 52 – July 2007 RISQUE output for the Otway Project CO_2 Storage Project. Each risk's quotient is plotted against a logarithmic y-axis that has been normalized to the Target Risk Quotient. An optimistic, planning and pessimistic risk quotient is given for each risk to represent the uncertainty in the inputs.

7.4.7. Risk Response and Management

The risk response plan resulting from risk assessments evolves along with the stages of the test project's characterisation through to operation and monitoring observations. Early in the project's characterisation and data acquisition stages, a risk targeted-uncertainty reduction process should take place. In ideal cases the development of a field for a test injection project provides an opportunity to collect much of the necessary data for some uncertainty reduction, such as a sampling and logging program to accompany the drilling of the injection or monitoring well. However, in some cases, if risk levels warrants and budget allows a targeted uncertainty reduction characterisation program may be required. It is at points such as these that risk- and cost-based decisions on project continuation may result in major project changes or project cancellation.

As a project progresses towards execution and operation, working thresholds are able to be established to assure risks associated with containment and performance are maintained at an acceptable level. Understanding these thresholds assists in forming the basis of the monitoring plan in terms of capabilities of technologies to determine whether these thresholds are being approached. An example of this is:

Fracture pressures, where a reasonable uncertainty range should be developed according to the existing data, a pressure threshold determined, iterative modelling of pressure to injection design so that maximum pressure is comfortably below the threshold, a pressure monitoring system designed installed, and an operational response plan developed if pressure approaches the threshold.

During the operational stages all risks should either be sufficiently below an acceptable risk level or have contingency measures in place to respond to an undesirable event taking place. The level of cost and effort applied to a risk response and monitoring plan should be based on the assessment of that risk with all its likelihoods and consequences considered. In all cases the project activities should follow appropriate industry standards and best practices in the management of risk.

8. Template for a successful project

8.1. Some organisational features of successful projects

In this Report, a total of 45 pilot projects have been identified. Because of the nature of research, it would be difficult to say that there were any 'failures' to the extent that all provided new information and perhaps unexpected but useful results. If the measure of failure is that a project is abandoned then approximately 20% of DSA and EOR projects have been abandoned, whereas to date no other class of project has been reported as 'abandoned'. However caution should be exercised with such a metric, for there may be many projects that have been terminated before they became public, but more importantly perhaps, a decision to not proceed with a project should just be seen as a wise decision in an inevitable process of assessment, before large amounts of money are spent.

Are there some collaborative arrangements that are more successful than others? The vast majority of projects have collaborative arrangements involving industry, government and the research community and a diversity of funding sources. But whatever the arrangements or membership, in most if not all cases the influence and the support of governments is clearly of great importance in defining the purpose of, and the expectations for the project. In many cases there was an explicit government CCS initiative such as the Regional Partnerships Program which resulted in a number of consortia developing around regions and ultimately injection sites. Some government initiatives may be multinational, as in the case of the EU or some of the Regional Partnerships (USA and Canada), national, such as in the case of some of the US Department of Energy projects or the flagship projects in Australia, or predominantly state or province, as in the Zerogen project in Queensland, Australia, or the Fenn/Big Valley project in Alberta, Canada. Even with projects which are not a response to a particular government CCS initiative, such as Otway in Australia, or perhaps K12B in Europe, there is nonetheless an increasing reliance on government at all levels, as the project evolves. Therefore realistically, at this stage of development of CCS, to be successful, a small scale injection project requires a significant level of financial involvement by government.

Another component of success may lie in having the right partners. A common thread in virtually all of these initiatives is to link research institutions with industrial partners in order to advance the science with practical field based trials, the industrial partners commonly providing the operational expertise required for these practical experiments, as well as some of the capital. Perhaps the most successful initiative in this context is the US Department of Energy's (DOE) Regional Carbon Sequestration Partnerships (RCSP) programme which encompasses approximately half of all the small scale projects that were considered in this Report. Initiated by the DOE's Office of Fossil Energy, the RCSP programme is a public/private cooperative effort which defines the purpose of the Program as *"To develop guidelines for the most suitable technologies, regulations, and infrastructure needs for CCS in different regions of the US and Canada"*.

The Partnerships working with the National Energy Technology Laboratory (NETL) consist of seven regional alliances of States and research institutions working within one or several closely related geological provinces. The partnerships each have a number of projects at the validation phase looking to test different types of storage systems, and although the research has a single nominated lead organisation, there will commonly be a number of Universities and other institutions co-operating in each of the projects and the related research. The RCSP storage programs have three distinct phases: 1) Characterisation, 2) Validation, 3) Development. In a number of these projects, the leading industrial partner tends to be a resource company, such as an oil or gas company which not only holds the lease over the test site but also has the relevant operational expertise to safely drill the deep boreholes which are a pre-requisite for these experiment as well as other operational aspects of the project. Due to a combination of its involvement in Regional Partnerships plus western Canadian CCS or acid gas initiatives, Canada has been active in several storage projects. Several of the most significant ones such as Weyburn, and the imminent Boundary Dam are outstanding projects at a commercial scale and therefore outside the scope of this Report. Pennwest/Cardium is an example of a particularly well documented pilot scale project (Hitchon, 2009) and along with CSEMP and Fenn/Big Valley and Regional Partnerships are evidence of a relatively high level of pilot project activity in Canada and of effective industry-government-research partnerships. Therefore as an example of a successful program, there is no question that overall, the Regional Partnership initiative has produced excellent science and does provide a valuable template for national initiatives.

Outside North America the pattern of public/ private partnerships is also seen to be the common model with the industrial partner a resource company, generally a petroleum producer, but in the case of the Carbfix project, unusually the partner is a publically owned utility company. Orkuveita Reykjavikur (Reykajavik Energy) operates the Hellisheidi geothermal power station which is providing the CO_2 for the test. This project also is an example of the international nature of the research collaboration which, outside of formal political unions such as the EU, is increasingly a feature of these programmes, with scientific expertise to Carbfix being contributed by the University of Toulouse France, and Columbia University USA as well as the University of Iceland.

Although the European Union has some major initiatives in the field of CCS, it has been less successful than the US DOE in delivering the smaller scale research and validation projects, possibly because there was greater focus on moving towards major demonstration projects. However these have faced more hurdles in their path to implementation than smaller scale projects would have done. As a consequence, compared to other parts of the world, the EU has lost ground in terms of demonstrating CO_2 storage with only four small scale projects in European Union countries, although it should not be forgotten that the iconic Sleipner Project of Statoil and its partners (which is outside the scope of this review because of its size) is world leading in many respects .The Lacq-Rousse project is one small scale project which unusually has been pursued primarily by one company, Total. To date there has been only limited release of scientific information but its success can be measured by the fact that it has demonstrated the entire CCS chain. The Ketzin Project has been scientifically very successful and there is undoubtedly more science that could be carried out at the site which would add to the success but its future is uncertain.

Six Australian projects are included in the small scale category, all of them involving close industry-government-research partnerships (the very large scale storage component of the Gorgon Project was outside the scope of this review). The most significant (non-commercial) national initiative is the Flagship Program, which has the potential to be successful, but as yet has not achieved the level of success of the Regional Partnerships program. The most notable Australian success to date and one of world significance, has been the Otway project, which has been underway for a number of years, with broadly based support from industry, government and research bodies, all brought together under the umbrella company CO2CRC Ltd. Features of the project that have contributed to that success are discussed elsewhere in this Report, but undoubtedly international scientific collaboration has been critical, with Lawrence Berkeley National Laboratory, USA and Simon Fraser University, Canada, the Korean Institute of Geology and Minerals (KIGAM) and the New Zealand Institute of Geological and Nuclear Sciences (IGNS) all being active participants in addition to a large number of international companies who provide funding and technical oversight. Another component in its success has been the very active participation of major operating companies.

Japan has successfully completed two small scale projects and the Tomakomai project, at the planning stage, may have an early small-scale test. The most significant and successful project has been the Nagaoka project which brought together a number of elements to achieve that success, including the fact that it was well characterised. One aspect which added to the world significance of the project, was the serendipitous occurrence of a major deep earthquake, which demonstrated very well that an earthquake does not necessarily lead to CO_2 leakage. Obviously serendipity is not a basis for success, but it does highlight the point that unanticipated results (or happenings) can be an important component of how a project is judged.

Is one type of project more successful than another? Are projects which are investigating storage as an end in itself, (depleted fields, deep saline aquifers and basalts) more successful than those which are more focussed on the use of the carbon dioxide to enhance oil or gas production (EOR or ECBM) with the permanent storage of the CO_2 a by-product of the extraction process? The results of EOR projects could be considered the most useful of the enhanced recovery types up to this time, since by studying the injection, migration and sweep efficiency within these projects, critical lessons may be learned on the expected behaviour of CO_2, which may be applied to projects in depleted oil and gas fields and deep saline aquifers. However a very successful DSA project could have much broader implications. There is no obvious measure of greater or less success amongst the types of projects. Very often the measure of success is based on achievement of a piece of the intended research specific to the formation or region to which it is directed. This is reflected by statements such as "*to demonstrate CO_2 sequestration in the Mount Simon Sandstone*", or "*to evaluate the technical and economical feasibility of extracting methane gas while storing CO_2 in Japanese coal seams*" or "*to inject CO_2 into a prevalent Illinois Basin oil-bearing interval (or equivalent) to directly measure CO_2 sequestration mass, enhanced oil recovery".* Obviously there is merit in having a very specific indicator of success such as those above, but there can be hazards in achieving a very specific aim in that there is also a high potential for failure, because the very precise objective is not actually met. It is important to remember that small scale projects are research projects and there will be surprises; the manner in which the Project deals with those surprises will be an important contributor to the success of the project.

It is interesting to note that although effective public outreach is seen as an important aspect of the success of a project, it is not given as a primary aim of most projects despite the fact that it is an important consideration when projects are conceived and frequently has significant effort devoted to it. It is a fact that a small scale project could be a scientific success, but could be seen as a failure if it results in very negative publicity and a hostile community. There are no obvious examples of this at the small scale, largely because community opposition arises at an early stage and projects are abandoned before they get underway. Nonetheless it is very important as part of the pathway to success, that community outreach figures prominently in the overall project strategy

8.2. Some technical features of successful projects

In the previous sections of this Review, examples of some of the key technologies applied to small scale projects have been discussed and examples provided where they have been successfully applied. It is useful now to attempt to draw these threads together into the general features which characterise small scale projects. This is not easy to do given that there are a relatively small number of projects and they show great diversity. Consequently it is impossible and probably meaningless to attempt to define an 'average" project in terms of the range of technologies that are applied. The difficulty arises largely from the fact that projects are always site specific and also have a range of objectives.

Table 4 - Project parameters according to types of projects.

PROJECT PARAMETER		DSA	EOR	DOGF	ECBM	Basalt
	Number of Projects	18	9	4	11	2
	Time (start of injection) (years)	3	2-3	3	3	5-6
	CO_2 Source	Multiple	Geological	Natural Gas	Multiple	Food/Magmatic
	Transport	Mainly truck	Pipe + Truck	Onsite	Truck	?
	CO_2 injected (tonnes)	15,000	20,000	64,000	2,000	2,000
	Injection Rate (tonnes/day)	127	74	84	31	36
	Injection Pressure (psi)	1,662	1,240	1,980	1,995	362
	Injection Depth (m)	1,600	1,600	2,900	700	700
	Cost US$	12	12	60	6	17
Percentage of Projects Using the Specific Technology	Downhole Seismic	100	40	100	40	50
	Groundwater Monitoring	70	80	50	80	100
	Soil Monitoring	40	100	70	30	100
	Atmospheric Monitoring	60	60	50	30	100
	Biological Monitoring	20	0	20	40	100
	Tracer Analysis	40	40	20	60	100
	Electromagnetic	20	10	0	0	0
	Gravity	0	20	0	0	0
	Pressure Logging	100	70	100	100	100
	Thermal Logging	90	60	100	100	50
	Wireline Logging	90	70	80	40	100
	Observation Well	60	40	80	80	50
	Geochemical	80	60	100	100	100
	INSAR	0	0	0	10	0
	Reservoir Modelling	90	90	100	100	100
	Coring	100	60	100	100	0
	Reflection Seismic	100	60	100	60	0
	Geological Model	90	80	100	90	50

(Columns DSA–Basalt are under the spanning header PROJECT TYPE.)

Nonetheless it is useful to see them as falling into one or other of four main groups: 1. Deep saline aquifers (DSA), 2. those focussed on Enhanced Oil recovery (EOR), 3. depleted oil and gas fields (DOGF) and 4. those which have Enhanced Coal Bed Methane (ECBM) as a focus. There is in addition a small group (two in total) of projects which are being undertaken to test storage in basalts. The key features of these five groups are summarised in Table 4.

In attempting to use Table 4 to draw out particular features of these various types of small scale projects, it is important to point out the shortcomings of the data compilation. The most important shortcoming is that the number of projects in any one group – a maximum of 18 and a minimum of 2. Therefore the compilation does not claim to be statistically meaningful. Rather it is provided to give some idea of the general features and may be useful for project proponents at the earliest stage of developing the concept, given that one of the first decisions (and perhaps a preordained requirement) will be whether the project is aimed at storage in a deep saline aquifer or a depleted gas field or is focussed on EOR or ECBM, or in basalt. Are there marked differences between the types?

In terms of time to proceed from initiation of the project to the start of injection, there is an indication that an EOR project will take the shortest time (2-3 years) to initiate and basalt the longest (5-6 years). The source and transport of CO_2 shows no significant pattern, but what is evident is that there is a trend in terms of the amount of CO_2 injected, with basalt and ECBM injecting approximately 2000 tonnes, DSA and EOR 15-20,000 tonnes and DOGF in excess of 60,000 tonnes. In terms of the rate of injection, ECBM and basalt show the lowest rate, at approximately 30 tonnes a day and DSA the highest at 130 tonnes a day, probably reflecting their permeabilities. Wellhead injection pressures are variable, from as little as 360 psi in basalts, to as much as approximately 2000 psi in the case of ECBM and DOGF. The depth of injection ranges from 700m in the case of ECBM and basalt projects, to 1600m for DSA and EOR projects, to 2900 m in the case of DOGF. Again, it is important to point to the bias arising from the exceptional depth of the Lacq-Rousse project with a depth of 4500-4600m. Finally the cost of the classes of projects are quite variable and as pointed out earlier, the reliability of the costs is questionable, but bearing those caveats in mind, it does appear that EOR projects are the lowest cost, DSA, EOR and Basalt are intermediate and DOGF are the most expensive, though again the costs are amplified by the inclusion of Lacq-Rousse (approximately US$80 million).

Given these uncertainties all that can be said is that to date, ECBM-related projects have been the lowest cost, largely because of their limited nature in terms of existing data, shallow depth and the small amount of CO_2 injected. The cost of the ‘average’ project involving injection into a ‘typical’ reservoir rock at a depth of say 1500 m and injecting say 20-40,000 tonnes of CO_2, could lie in the range from approximately US$15-40 million and it is likely to take three years to progress the project from concept approval to injection. However, once again it is important to restate the uncertainties of these numbers.

What about the range of technologies, largely relating to monitoring? Do they show a preferential pattern in Table 4? Again it is necessary to sound a cautionary note on the limitations of the data. A percentage value is given, for example that 70% of deep saline aquifer projects have some form of groundwater monitoring. However the sample size is quite small for most technologies and there is great variability between projects and therefore it would be unwise to take the percentage values as anything more than indicative.

Downhole seismic is a feature of all DSA and DOGF projects, but less than half the EOR and ECBM projects deploy it. Groundwater monitoring is undertaken in all five types of projects and in the majority of individual projects. Soil monitoring is also fairly common, with the exception of ECBM projects where only one-third of the projects report soil monitoring. Approximately one-half of all projects report undertaking some form of atmospheric monitoring, but few projects report carrying out biological monitoring or investigation. The use of tracers is reported by approximately half the projects. Gravity studies of any sort are rarely undertaken, presumably indicating that most projects feel it will tell them little. This also applies to INSAR. Given that the table is only for small scale projects, it is likely that injections of 100,000 tonnes or less will not produce a measurable INSAR response. A number of other technologies are widely used across all project types. Some of them, such as well head pressure, are required as part of normal operations. Thermal logging and wireline logging are proving to be increasingly important tools and are widely applied; coring and geological and reservoir modelling are almost universally applied (specific examples of projects that have successfully applied modelling techniques are discussed earlier in this review). Reflection seismic is used in all DSA and DOGF projects (in some cases it may be pre-existing seismic data rather than being collected specifically for the project), but is much less common for EOR projects (surprisingly perhaps) and for ECBM projects. Finally observation wells and related geochemical studies are a feature of most DSA, DOGF and ECBM projects, but are much less common in EOR projects.

Bearing all this in mind, what might an ‘average’ project in a sedimentary basin involve in terms of monitoring and related studies. Again it is important to emphasize how site-specific and ‘problem-specific the portfolio is. Nonetheless downhole seismic, groundwater monitoring, pressure, thermal and wireline logging are used by most projects along with geological and reservoir modelling, coring and reflection seismic. Atmospheric monitoring is undertaken by about half of all projects and tracer analysis is fairly common. However gravity, INSAR and biological studies are seldom undertaken. Whilst data are provided for basalt projects, it is not possible to draw any conclusions on then, given that there are only two.

8.3. Template for successful projects?

There is no such thing as a 'perfect project' that can be used as a template for establishing the technical or governance parameters for a future project and there is no recipe that ensures a successful project. But what has been provided in this Review is an indication of how a project might be organised and undertaken, the conditions that might prevail (depth, amount of CO_2 likely to be injected, injection rate, timing, cost) and the range of technologies that should or might be deployed. Again it is important to reiterate that these parameters will vary, depending on the objectives of the project and the particular features of the site. Nonetheless, Table 4 may be a useful guide for the initial technical and scientific stages of planning a project.

- The general objectives of the project are clear to (and agreed by) all participants from the start.
- There is confidence that a site has been identified that is likely to be geologically suitable and accessible.
- Suitable, affordable and adequate supply of CO_2 is available.
- Key stakeholders, especially the local community, are effectively engaged at an early stage.
- The decision-making process and key milestones on which decisions will rest are clear and there is agreement on liability issues.
- The governance structure and lines of responsibility are defined.
- The regulator is fully engaged at all stages of the project and regulations and key performance indicators, or mechanisms for identifying them are in place.
- The budget and a staged approach to ensuring adequate coverage of contingencies is in place.
- Funding is in place or there is a clear pathway for obtaining the necessary funding.
- Baseline studies are initiated very early in the project.
- Realistic time frame is agreed for undertaking the project.
- Scientific objectives and strategy for achieving them are in place.
- Outstanding scientific team assembled, with the necessary range of skills.
- Database developed for all scientific, operational and other project information and protocols agreed for data entry.
- Basis for all key decisions clearly documented.
- Best practice will be followed at all times for health safety and environmental issues.
- Clear protocols in place for commencing, suspending, and concluding injection of CO_2 and for well closure and abandonment.
- Transparency in the disclosure of monitoring results.
- A formalised process for risk management is in place from the start of the project.
- Agreements in place for ensuring there is provision (financial, staff and time) for full documentation of the project, including a comprehensive 'close out' report at the conclusion of the project.

8.4. Best Practice Manuals

Given the variability between small scale projects as evidenced by this review, it would be impractical to expect that a single best practice guide could be developed that would suit all future small scale injection projects. Nonetheless this Report does provide pointers to many of the key issues that must be taken into account when developing and undertaking a project and it is perhaps useful to summarise some of those here. It is also useful to summarise the guides that are currently in existence, based on the review undertaken by Soroka (2011) supplemented by a number of recent publications.

These range from very topic-specific manuals to those covering the entire CCS chain including transport. They vary in the level of detail, with some offering overviews of the concepts, others offering highly detailed discussions and some providing the technical operations, calculations and geologic parameters that went into real world projects.

Soroka (2011) provides a summary of the best practice manuals and some guidelines that have been published to 2010. Several more recent ones have been incorporated into the compilation, notably the Weyburn and Pembina projects together with information currently being compiled for the Otway Project (Cook, 2013).

Most of those listed relate to specific projects, several of which are large scale projects, where application to small scale injections may be limited. Some of the manuals refer to very specific aspects, such as the legal framework or methodologies, such as risk evaluation of wells, or determination of storage capacity. A summary of the content of these BPMs is provided in Table 5.

Table 5 – Best Practice Manuals.

	Best Practice Manuals (BPMs)
IEAGHG	Best Practices for Validating CO_2 Geological Storage: Observations and Guidance from the IEAGHG Weyburn-Midale CO_2 Monitoring and Storage Project (2012) A key deliverable of the IEA's 11-year monitoring program at the Weyburn EOR injection and storage project is a BPM covering the scope and learnings of the project. It includes technical components (including site characterisation, monitoring and verification, wellbore integrity and performance assessment), and policy components (including regulatory issues, public communication and outreach, and business environment). Available from: Geoscience Publishing, 2012
WRI Non-site specific	CCS Regulatory Matrix (2012) WRI has developed a online tool enable decision-makers to quickly evaluate how different frameworks (WRI's CCS Guidelines, IEA CCS Model Framework, U.S. EPA Class VI Regulations, and E.U. Directive 2009/31/EC) deal with key issues, like site selection, characterization requirements and long-term liability. http://www.wri.org/project/carbon-dioxide-capture-storage/proposal-matrix
CO2Care	Report on the current site abandonment methodologies in relevant industries (2012) This report introduces the general aspects of site abandonment, reviews current site abandonment methodologies in relevant industries and provides a basis for permanent well abandonment (activities) with respect to acid gas disposal. This information was then used to develop a best practice for the abandonment of CO_2 storage sites, and recommendations for future abandonment activities and regulations. http://www.co2care.org/FileDownload.aspx?IdFile=307&From=Publications
DNV Non-site specific	JIP Framework for risk evaluation of wells at CO_2 storage sites (2011) The DNV, through the CO2Wells JIP, has developed a transparent risk-based guideline for evaluating the integrity of wells, and procedure for re-qualification of wells for CO_2 injection. This guideline provides the support the development of CO_2 geological storage projects up to the point of final investment decision. This document is a supplement to the previous guideline for selection and qualification of sites and projects for geological storage of CO_2. The guideline provides a tool for independent validation and verification, building confidence among regulators and stakeholders in risk informed approaches to selection and management of storage sites. http://www.dnv.com/binaries/co2wells_guideline_tcm4-465269.pdf
MRCSP	Best Practice Manual for Midwest Regional Carbon Sequestration Partnership Phase II Geological Sequestration Field Validation Tests (2011) This BPM describes the key lessons learned from three injection tests performed as phase II of the Midwest Regional Carbon Sequestration Partnership. A strong focus in this is the development of community awareness and moving through the US regulatory process. The BPM steps through, with good detail, the technical assessment of most CO_2 storage aspects, beginning with qualitative site screening/selection, site characterisation and covering CO_2 supply, well design, and monitoring operations. This BPM is an excellent guide to developing a test project. http://216.109.210.162/userdata/phase_II_reports/final_best_practice_geologic_sequestration_manual final.pdf

	Best Practice Manuals (BPMs)
NETL Non-site specific	Risk analysis and simulation for geologic storage of CO_2 (Revised 2013) As with the site screening BPM, NETL has produced a generic (i.e. non site specific) publication that includes both an understanding of what risk and numerical simulation is and why it is an essential aspect to CCS. Although not specifically addressed, this BPM was developed from the lessons learned at numerous projects run by the RCSP. The BPM includes, for risk: fundamentals, identification, assessment (including quantifying) characterization and mitigation; and for simulation the many different processes (thermal, chemical, biological, etc…) that are required for accurate simulation. The BPM then covers how risk plans and numerical simulations can be applied separately and together to a CCS project in order to handle the potential risks of a CCS site. http://www.netl.doe.gov/technologies/carbon_seq/refshelf/BPM_RiskAnalysisSimulation.pdf
NETL Non-site specific Case study on Illinois project	Best practices for: Site screening, site selection, and initial characterization for storage of CO_2 in deep geologic formations (2010) The USDOE, through NETL, has released several BPMs on CCS. This one relates specifically to the needs of a generic CCS project covering all possible opportunities and what is necessary to select and characterize a site. It addresses this from a fundamental standpoint covering basic scientific understanding and only occasionally inserting application examples. The report is a 110 page comprehensive discussion of 'what you need to know' with regard to storage. It covers identifying and developing all potential injection sites and requirements for each type (saline/depleted reservoir/coal), data analysis, injection strategies, model development and refinement, capacity estimation and overall suitability analysis. It also includes social and environmental considerations in developing and operating a site. It does not cover simulation, risk and monitoring to a technical level as there are separate BPMs covering these. http://www.netl.doe.gov/technologies/carbon_seq/refshelf/BPM-SiteScreening.pdf
IEA	CCS Model Regulatory Framework (2010) This framework provides a guideline for understanding what must go into developing regulations for CCS. Covering the entire CCS chain from capture through to storage site closure it provides a comprehensive discussion of the issues regulators face. It includes reporting and classification issues, liability, hazards and risk, inspections and monitoring, financial aspects and it addresses areas that need to be standardized such as fluid composition. http://www.iea.org/ccs/legal/model_framework.pdf
WRI Barendrecht Wallula FutureGen Otway Jamestown CHP	Guidelines for community engagement in CCS (2010) Comprehensive review of the CCS community engagement process including understanding the importance of community engagement, understanding the needs of different stakeholders, applying community engagement to the specifics of CCS throughout the entire life of a project, how to cover impacts and risks effectively and what reactions to expect. It also addresses the best practice for presenting and exchanging information and then provides numerous examples from around the world of the case studies where these lessons were learned. http://pdf.wri.org/ccs_and_community_engagement.pdf
NETL Provides tables showing geology of all	Best practices for: Geologic storage formation classification: Understanding its importance and impacts on CCS opportunities in the United States (2010) Written for the purpose of understanding and applying geology to a CCS project. It begins with a background on geology covering geological terminology, rock types and how they fit into CCS and which are most suitable. It then becomes more technical (although written for non-geologists) covering different depositional

	Best Practice Manuals (BPMs)
RSCP projects	environments and what each one means for CCS. This BPM is mainly focussed on understanding how geology affects a CCS project. http://www.netl.doe.gov/technologies/carbon_seq/refshelf/BPM_GeologicStorageClassification.pdf
DNV Non-site specific	Guideline for selection and qualification of sites and projects for geological storage of CO_2 (2010) A step by step guide to selecting a CO_2 storage site. From the pre-feasibility stages of developing a screening plan to data acquisition, capacity estimation, modelling and simulation, risk assessment and regulation it covers the many different aspects that need to be considered and provides "best practice" for accomplishing each step often providing deliverables that could be expected. Although the majority of the BPM is on site selection and characterization it does also cover operation and closure. However, although it must be assumed that the best practices are based on lessons-learned; there are few direct case studies or examples that are mentioned as proof of the success of the best practices provided. http://www.dnv.com.au/binaries/CO2QUALSTORE_guideline_tcm162-412142.pdf
NETL Non-site specific	Best Practices for: Public outreach and education for carbon storage projects (Revised 2013) Community engagement has been stressed as a very important aspect of successfully developing a CCS project and this BPM takes the short social outreach discussion from the site screening BPM and expands it using a generic approach combining lessons learned from numerous projects in a non-specific way. It covers the importance of public outreach and how public outreach should be integrated into the development of the project. It covers identifying stakeholders, an information gathering practice termed 'social characterization', developing plans and strategies, and outlines what key messages should be and how to tailor them to a public audience. http://www.netl.doe.gov/technologies/carbon_seq/refshelf/BPM_PublicOutreach.pdf
NETL Strandplain Nugget Mt. Simon San Joaquin Williston + Others to lesser extent	Best Practices for: Monitoring, verification, and accounting of CO_2 stored in deep geologic formations (2012 Update) Comprehensive BPM addressing the need for and requirements of a monitoring program at a CCS project. It covers atmospheric, near-surface, and subsurface monitoring, simulation techniques, geophysical techniques, geochemical techniques and crustal and surface techniques. It covers pre-operational, operational, and post-operational phases of monitoring and provides a discussion on possible regulatory requirements. It also utilizes numerous case studies and international projects to address what has been achieved so far and what will be required in the future. http://www.netl.doe.gov/technologies/carbon_seq/refshelf/BPM-MVA-2012.pdf
CO_2 Capture Project Large number of case studies from around the world	A technical basis for carbon dioxide storage (2009) Written by individuals from a wide range of oil and gas companies, this BPM takes the experiences these companies have had in CO_2 injection and compiles them into a single publication. The BPM covers, with enough detail to be considered beyond basic, a technical understanding of the aspects of CO_2 storage. Beginning with background and site selection and covering operation, closure and monitoring the BPM is a guide to developing a storage project. A significant addition that this publication includes and others do not include is a detailed guide for well construction and completion that contains discussions on materials and the factors that govern which you can use and when. The BPM also uses a large number of case studies, separated from the text as standalone examples, to illustrate how the advice given in each section was used in reality. http://www.co2captureproject.org/co2_storage_technical_book.html

	Best Practice Manuals (BPMs)
WRI Non-site specific	Guidelines for CCS (2008) Covers the entire CCS process (Capture, transport, storage) and therefore more of an overview of a theoretical project development and what proponents 'should' consider and do to be successful. It is best described as a dictionary of CCS project aspects rather than a BPM. http://pdf.wri.org/ccs_guidelines.pdf
SACS/ CO2STORE Sleipner Schwarze Pumpe Kalundborg Mid Norway The Valleys	Best practice for the storage of CO_2 in saline aquifers (2008) Undergone several revisions since first being published in 2003 covering the Sleipner Project. The latest version is a comprehensive 277 page manual published in 2008. It deals with all aspects of storage in saline aquifers from identifying ideal reservoir and seal properties to capacity estimation, predictive flow modelling, geochemical and geomechanical site characterization and includes operating the site. It also covers cost estimation, transport needs, monitoring plan design and history matching based on monitoring data and safety and risk assessment procedures. The information is presented through case studies of what was done and learned at 5 separate projects including Sleipner and Schwarze Pumpe. http://nora.nerc.ac.uk/2959/
UCL	Carbon Capture Legal Program (Updated, online since June 2007) Although not a BPM, this website provides a fairly comprehensive summarization, analysis, and response to global CCS legislation and regulations. The CCLP offers both their own interpretation of the legal works as well as links to the legislation and links to position and discussion papers from other organizations. Along with the section dedicated to existing legislation, the CCLP also provides several short-report style papers and presentations that address particular issues surrounding the workings of regulatory issues. Some of these are relevant to small scale projects http://www.ucl.ac.uk/cclp/ccsthink.php
CO2NET Non-site specific	CO2NET2 Work Package 7 Best Practice Review (2004) This is a basic manual, with, for example, the discussion on simulation and modelling limited to acknowledging that software packages exist. It does summarise the entire CCS process from site selection to closure. http://www.dnv.com/binaries/CO2NET2WP7BestPracticeReview-04v2_tcm4-20786.pdf
GEOSEQ Frio Otway In Salah	Geologic carbon dioxide sequestration: Site evaluation to implementation (2004) This is a summary and therefore does not cover the breadth or detail of other BPMs i.e. discussion of saline formations is limited to a few pages with the majority of the manual covering a non-detailed discussion on capacity estimation. However, there are subjects that are addressed that other manuals do not, such as a section dedicated to EOR and the oil properties that would be conducive to an EOR operation. Another topic discussed (although only briefly) that other manuals do not provide much information on, is how to deal with impure streams of CO_2. Although, as mentioned earlier, this manual is fairly basic in general, an exception to this is monitoring and verification where technical detail is given including real world examples. http://www.netl.doe.gov/technologies/carbon_seq/refshelf/GEO-SEQ_BestPract_Rev1-1.pdf

	Best Practice Manuals (BPMs)
CO2CRC	The CO2CRC Otway Project: Lessons Learned. (2013 in press) This in press report focuses on the methodologies used by the Stage I Project rather than the scientific results (which have been mostly published in scientific journals). The organisational and governance arrangements, communications strategy, plant design, characterisation, and a range of monitoring activities are discussed in some detail. Stage II, which focuses on analysis of residual trapping is summarised in the document
CO_2-EOR Pembina Project	Pembina Cardium CO_2 Monitoring Pilot : a CO_2-EOR project, Alberta, Canada : final report (2009) This Report summarises the methodologies used and the results of the CO_2-EOR Pembina Project, Alberta, Canada. It summarises the methods used to characterise the site regionally and locally and discusses the geological, geochemical and reservoir flow models developed by the project. The environmental monitoring carried out and aspects of the instrumentation are also discussed in this excellent publication Available from: Geoscience Publishing, 2012

Table 6 – Scope and content of some best practice manuals.

	Pre-feasibility	Site Selection	Capacity Estimation	Simulation and Modelling	Construction	Operation	Closure	Monitoring and Verification	Risk Assessment	Community Consultation	Regulation
SACS	Basic	Technical	Technical	Technical	-	Basic	Detailed	Technical	Detailed	Basic	Basic
NETL (SS)	Basic	Detailed	Technical	Basic	-	-	-	-	Basic	Basic	Detailed
NETL (RA)	-	-	-	Technical	-	-	-	-	Technical	-	-
NETL (MV)	-	-	-	-	-	Technical	Technical	Technical	Basic	-	Basic
NETL (GS)	Technical	Technical	-	-	-	-	-	-	-	-	-
NETL (PO)	-	-	-	-	-	-	-	-	-	Technical	-
WRI (CCS)	Basic	Detailed	Basic	Basic	Basic	Basic	Detailed	Detailed	Detailed	Basic	Detailed
WRI (CE)	Basic	Basic	-	-	Basic	Basic	Basic	Basic	-	Detailed	Basic
DNV	Detailed	Detailed	Detailed	Basic	-	Detailed	Detailed	Basic	Detailed	-	Detailed
DNV (Wells)	Detailed	Detailed	-	-	-	-	-	-	Technical	-	-
CO2Cap	-	Basic	Basic	-	Detailed	Detailed	Basic	Technical	Basic	-	-
GEOSEQ	-	Basic	Basic	Basic	-	-	-	Detailed	-	-	-
CO2NET	-	Basic	Basic	Basic	-	Basic	-	Basic	-	-	-
IEA	-	-	-	-	-	-	-	-	-	-	Technical
CO2Cap (R)	-	-	-	-	-	-	-	-	-	-	Technical
MRCSP	Basic	Basic	-	Basic	Technical	Technical	-	Technical	-	-	-
CO2Care	-	-	-	-	-	-	Technical	-	-	-	-
GCCSI/ICF	Detailed	Basic	Basic	Basic	Basic	-	Technical	-	-	Basic	Basic
CO2CRC	Detailed	Detailed	Basic	Detailed	Detailed	Detailed	Basic	Detailed	Detailed	Detailed	Detailed

-	Not Covered
Basic	Briefly covered in a generic way
Detailed	Comprehensive discussion, generally generic
Technical	Provides technical detail of projects, generally comprehensive
NETL (SS)	Best Practises for: Site screening, site selection, and initial characterization for storage of CO_2 in deep geologic formations
NETL (RA)	Risk analysis and simulations for geologic storage of CO_2
NETL (MV)	Best Practices for: Monitoring, verification, and accounting of CO_2 stored in deep geologic formations
NETL (GS)	Best Practices for: Geological storage formation classification: Understanding its importance and impacts on CCS opportunities in the United States
NETL (PO)	Best Practices for: Public outreach and education for carbon storage projects
WRI (CCS)	Guidelines for CCS
WRI (CE)	Guidelines for community engagement in CCS

It is not possible to cover all the detail of these various BPMs within this Report, but it is perhaps useful to provide here a checklist of some of the key issues to be covered when embarking on a small scale project.

However, as discussed earlier in this chapter and elsewhere in this Report, there are other less quantifiable criteria, that are at least as important in terms of helping to maximise the chance of success of a small scale injections and of taking it along the decision pathway. These include (not necessarily in order):

- The objectives of the project must be agreed and clearly defined in a manner that addresses the expectations of all key stakeholders, whilst recognising that as a research/pilot project, not all objectives will necessarily be achieved. For this reason, it is also important to also prioritise objectives as well as retain the necessary degree of flexibility so that if there are unexpected outcomes, objectives can be modified or re prioritised in a sensible manner.
- If the project is being undertaken by a consortium (and most projects are), ensure that there is full alignment between all participants on issues such as budgets, funding, responsibilities, liabilities, governance, confidentiality, communications, operations and management and board responsibilities.
- Have an agreed and well defined work flow with clear decision points to enable the project to be logically taken from identification of the opportunity through to the operate stage and finally the abandon stage. An example of the type of general schema used by industry is provided in this Report, which is known to work for small scale projects, but obviously each project must develop its own detailed work flow and decision tree, that meets the specific needs of the project.
- To the extent possible ensure that there is alignment of funding, budgets, and the expenditure profile over the life of the project.
- Have agreement on how and on what basis the project will be abandoned at the conclusion of the project including ensuring that there is adequate funding available meet abandonment (including remediation) requirements.
- Engage with the local community at the earliest possible opportunity; ensure that they learn about the project from members of the project and not from the media; ensure that there is a local liaison officer or community officer, who lives in the vicinity of the site and who can act as the first point of contact, but at the same time ensure that the opportunity is there to talk directly to the scientists and engineers and establish an open and transparent approach to all aspects of the project.
- Assume that negotiations with landowners and related land access issues will take longer than anticipated and build adequate flexibility into the system to handle unavoidable delays.
- Ensure that there is clarity about the regulatory regime under which the project will operate. Alternatively if this is not clear, then ensure that the regulators are consulted at the start and that they agree to work along with the project to develop a sensible and workable regulatory regime.
- Key performance indicators will need to be agreed with the regulators, so that objective of monitoring are clear and to ensure that the project can confidently move forward in the knowledge that the “ground rules” will not change in the middle of the project. Where regulations already exist ensure that will meet the needs of the project, and that you can meet

the requirements of the regulations. If you cannot then either the project will need to be revised, or a waiver sought from the regulator.

- Collect and analyse all available surface and sub surface information from Government and particularly from industry where injection is proposed in a brown field site. Identify what new information will be required and map out the logistics of acquiring that information.
- Secure an adequate supply of carbon dioxide at a known cost; ensure that the composition of the gas will meet the needs of the project.
- Undertake comprehensive characterisation of the site and have a system in place so that all models are updated as new information becomes available. Characterisation should include a broad understanding of the geological setting of the site including depositional environments of reservoirs and seals, structural setting, geomechanical properties, seismicity, ground waters (dynamics and composition), geological and reservoir models.
- Develop plans for a monitoring regime that will deliver data to address key performance indicators, address regulatory needs, meet community expectations and provide assurance to the community
- Before any injection takes place, collect base line data and ensure that there is adequate knowledge of natural variability, both temporal and spatial, for all key parameters.
- At a very early stage have very clear protocols for data collection and curation, the disbursement and use of samples, the deposition and accession of information in a project database, publication and dissemination of scientific outcomes.
- Ensure that adequate provision is made for the publication of a comprehensive “close out” report at the conclusion of the project that adequately summarises the lessons learned.
- In moving to the operation phase ensure that ‘best practice ‘ is followed at all stages and by all project participants.
- Have HSE and other protocols in place and ensure that they are enforced with all staff and all contractors and sub contractors. It is likely that industry participants, from the oil and gas industry in particular, involved in a CCS consortia, will be well experienced in this area and will be well positioned to provide advice. Importantly there are a number of schemes in place that can be readily adapted for use in a small scale project, rather than the project attempting to develop its own protocols from scratch.
- Risk assessment and management should be embedded within all aspects of the project including research, monitoring and operations.
- A broader communications strategy should be in place, at the regional national and international levels, for the project, particularly once it starts moving towards the operational phase, in order to provide positive stories on the project to the media and also to address any incidents at the site, should they occur.
- Operational details should be captured so that practical lessons learned can be passed on to other projects. Obviously there is no single model for the operational phase of the project as this will vary greatly from project to project depending on the geological setting and the objectives of the project.
- The monitoring program will have become fully operational alongside other activities and will require careful and ongoing assessment of its accuracy and reliability, including the reliability and accuracy of laboratory analyses. This Report documents the range of monitoring

techniques that can be deployed but does not attempt to say what should be deployed for this will vary greatly with the conditions at the site and the objectives of the project, including perhaps the objective of testing new instrumentation that may or may not work.

- Where ultra-sensitive tracers are to be used, care must be taken to avoid contamination of the site and of instrumentation.
- The closure and abandonment stages of small scale projects are in general not well documented; it is important the information relating to these concluding activities is captured and made available, including information on any post closure monitoring.
- Perhaps inevitably at the conclusion of a project there is a tendency to emphasize the positive aspects of a project and whilst these are very important, it is also important to capture information on the things that did not work or which could have been done better or faster or more cost effectively.

In conclusion, there is no single all-encompassing “best practice” for small scale projects that can be followed slavishly. Rather there are many lessons to be learned from the more than 40 small scale projects that have been reviewed in this Report which will be applicable to other projects to varying degrees. This concluding chapter attempts to set out some of the generic lessons that can be used or adapted to suit the particular needs of a project.

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11. Appendices

Appendix 1 –Summary of parameters and features for all small scale projects

Appendix 2 – Small scale project data sheets for small scale projects

Appendix 3 – Bibliography of small scale projects

Appendix 4 – Summary of some parameters and features for large scale projects

Appendices

Developing a small scale CO_2 test injection: Experience to date and best practice

Peter Cook, Rick Causebrook, Karsten Michael and Max Watson

April 2013

CO2CRC Report No: RPT13-4294

for

IEA Environmental Projects Ltd.

IEA Greenhouse Gas R&D Programme

Stoke Orchard, Cheltenham

Gloucestershire UK GL52 7RZ

FINAL DRAFT

CO2CRC Technologies

Appendix 1–Summary of parameters and features for all small scale projects

Detailed summaries of all small scale injection projects are provided in the MS *e*xcel format, please see attached.

Parameters provided in the summary database for small scale projects.	
Project Name	Total cost of project
Revised after response	Cost Currency coverted USD
New reference	Seismic monitoring
Type	Water monitoring
Project Scale	Soil Monitoring
Project owner	Atmospheric monitoring
Project operator	Ecological monitoring
Prime Contact	Tracer analysis
Title	Electromagnetic
Phone	Gravity studies
Email	Pressure logging
Project Location	Thermal logging
Country	Wireline logging
Coordinates	Observation well?
Current status	Geochemical research/Fluid sampling
Project planning start	InSAR
Year of first injection	Other monitoring technolgoies
Storage Target	Reservoir modelling
CO_2 Source	Coring
CO2 transport/delivery	Seismic
Total Injection (tonnes)	Geologic model
Planned injection (tonnes)	Reservoir
Injection rate	Project websites
Injection Pressure (psi)	
Injection depth	

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Technologies

Appendix 2–Small scale project data sheets

The project summaries included in this appendix are listed below. Many of these summaries have been compiled with additional information supplied by the project contacts listed in each individual summary, or a fellow representative.

PROJECT SUMMARY

Project name:
BSCSP Basalt Sequestration Pilot Test

Project organisation:
Big Sky Carbon Sequestration Partnership (BSCSP), Montana State, (406) 994-3800 bigskycarbon@montana.edu

Project type:
Basalt

Project Scale
Small scale (<100,000 t)

Type and depth of reservoir:
Basalt, 823-884 meters

Total cost of project:
US$26,300,000

Location:
Pasco, Walla Walla County, Washington, USA

Year of first injection:
2013

Current status:
Planned

Type of Seal:
Dense Basalt

PROJECT DETAILS

	Project operator	Batelle	**Project contact phone**	(406) 994-4399
	Project contact	Lee Spangler	**Project contact email**	spangler@montana.edu
	Project location	Pasco, Walla Walla County, Washington, USA	**CO_2 source**	Food grade
	Injection site coordinates	46°05'00"N, 118°52'60"W	**CO_2 transport/delivery**	Truck/rail
	Project planning start	2007	**Injection rate**	Not known
	Duration of injection	2 weeks	**Injection depth**	Not known
	Planned injection volume	907 tonnes (1000 short tons)	**Total volume injected**	Not known
	Reservoir porosity	Not known	**Reservoir permeability**	Not known
MONITORING	**Seismic monitoring**	3D, 2D	**Gravity studies**	Not known
	Water monitoring	Surface	**Pressure logging**	Not known
	Soil monitoring	Soil gas flux	**Thermal logging**	Not known
	Atmospheric monitoring	CO2 flux monitoring, eddy covariance	**Wireline logging**	Cased hole
	Ecological monitoring	Not known	**Observation well**	No dedicated well
	Tracer analysis	introduced elements	**Geochemical research/Fluid sampling**	Not known
	Electromagnetic	Not known	**InSAR**	Performed
RESERVOIR STUDIES	**Reservoir modelling**	Yes	**Geologic model**	Not known
	Coring	Yes	**Seismic**	Yes - Vibroseis
	Other technologies	Not known		

Project context

The Basalt Sequestration Pilot Test was developed under the The Big Sky Carbon Sequestration Partnership (BSCSP), one of seven regional partnerships working under the Department of Energy's (DOE) Regional Carbon Sequestration Partnership (RCSP). The DOE created a network of seven RCSPs to help develop the technology, infrastructure, and regulations to implement large-scale carbon doixide (CO_2) sequestration in different regions and geologic formations within the Nation. The project is a partnership between BSCSP, Battelle and Boise Inc. to take promising laboratory results for capturing and permanently storing CO_2 to the next testing step – a field test on Boise property near Wallula, WA.

Aims of the project

The overall goal of the pilot project is to prepare for and conduct a small scale CO_2 sequestration project in deep basalts of the Columbia River Basalt Group. Specifically the project aims to:

1) Safely inject 1000 tons of supercritical CO_2 and several tracers to identify CO_2 presence into the basalt formation, 2) tracking the injected CO_2 plume within the reservoir zone, and 3) assessing for leakage within the formation by using geophysical sensors and standard hydrologic pressure monitoring systems.

Ownership and liability

Not known.

Regulatory and approval conditions

The project had to gain a permit for the injection is approved by the Washington State Department of Ecology. In gaining approval for the project detailed characterisation utilising seismic data to determine formation's thickness, permeability, porosity, mineral makeup, caprock properties. Understanding the water quality, in particular through the basalt storage target, was an important step in the monitoring and permitting process for the State of Washington.

Pre-injection geological database and site characterisation

Characterizing the basalt rocks and determining site suitability for the pilot test was the first step of the project. This was done by collecting and analysing seismic data. Using seismic data from two Vibroseis ("Thumper") trucks, researchers examined a four mile swath of land located near the field site. Drilling began on January 14, 2009 and reached a depth of 4,110 feet on April 6, 2009. Rock samples and basalt cores collected during drilling provided researchers with data on the rock layers and geochemistry of the formation.

Three zones within the Grande Rhonde basalt formation as suitable to inject CO_2. All three zones are located between 2,716 to 2,910 feet and are referred to as part of the Slack Canyon Member (Slack Canyon flow #1, Slack Canyon flow #2, and the Ortley flow). Each flow contains a seal or "caprock," which will effectively seal the sequestered CO2 from leaking. Each caprock measured between 35 and 99 feet and was tested for pressure and injection flow-rate capabilities.

Results from groundwater sampling showed that the hydrochemical properties of the site were similar to other basalt groundwaters, exhibiting elevated levels of pH, fluoride, sodium and other minerals due to the geochemical evolution of the surrounding area, such as reactive processes to volcanic phases and other hydrothermal variables. The results of the water sampling indicated elevated levels of fluoride in the groundwater that exceeded recommended standards and suitable for sequestration.

Source of CO_2

The food grade CO_2 was purchased from a commercial source.

Transport of CO_2

The CO_2 will be transported by rail from the supplier directly to the field pilot study area.

Additional project details

Although the injection of CO_2 has not occurred, the project has progressed to hydraulic testing and plans to run the CO_2 injection in 2013.

Stakeholder engagement

Public outreach was an important component of this project in order to share project information, address peoples' questions or concerns and obtain input on the project from community members. Public outreach was a collective goal of the BSCSP and conducted in coordination with all of the partnerships projects. There were public outreach events, education efforts and training opportunities for students and young professionals.

The project intends to become a platform for collaboration across academia, industry, environmental non-government organisations, and regulatory and government officials to discuss to role carbon sequestration can play as a technological solution to regional energy issues.

Risk assessment process

Not known.

Significant learnings from the project

Not known.

PROJECT SUMMARY

Project name:
CARBFIX

Project organisation:
Reykjavik Energy (Orkuveita Reykjavíkur)

Project type:
Basalt - Mineral Carbonation

Project scale:
Small scale (250 t injected before Jan 2013)

Type and depth of reservoir:
Basalt, 400-800 metres

Total cost of project:
About 7 million EUR at end of 2011

Location:
Reykjavik, Iceland

Year of first injection:
2012

Current status:
Operational

Type of seal:
Basalt

PROJECT DETAILS

	Project operator	Reykjavik Energy	**Project contact phone**	+354 516 6000
	Project contact	Edda Sif Aradottir	**Project contact email**	edda.sif.aradottir@or.is
	Project location	Reykjavik, Iceland	**CO_2 source**	Magmatic, Geothermal Power plant
	Injection site coordinates	64°5'30"N, 21°30'07"W	**CO_2 transport/delivery**	Pipeline (3 km)
	Project planning start	2007	**Injection rate**	2-3 kg/s of carbonated water (CO_2 dissolved in water during injection)
	Duration of injection	At least 6 months	**Injection pressure**	25 bars at wellhead.
	Planned injection volume	2200 tonnes /year	**Total volume injected**	250 tonnes, injection resumed in Jan 2013
	Reservoir porosity	8.5%	**Reservoir permeability**	$300*10^{-15}$ m^2 lateral and $1700*10^{-15}$ m^2 vertical
MONITORING	**Seismic monitoring**	Not performed	**Gravity studies**	Not performed
	Water monitoring	Before and after injection. In injection well and 9 monitoring wells	**Pressure logging**	Wellhead and in reservoir
	Soil monitoring	CO2 soil flux monitoring	**Thermal logging**	Wellhead
	Atmospheric monitoring	CO_2 concentration monitoring, weather station in operation since 2010 at injection site	**Wireline logging**	Neutron porosity, gamma ray, resistivity, width, temperature
	Ecological monitoring	Impact of CO_2 on deep biota (carried out by IPGP, Paris)	**Observation well**	9 Dedicated monitoring wells
	Tracer analysis	SF_6, SF_5CF_3, Amidorhodamine G, ^{14}C	**Geochemical research/Fluid sampling**	Detailed water composition analysis
	Electromagnetic	Not performed	**InSAR**	Not performed
RESERVOIR STUDIES	**Reservoir modelling**	3D reactive transport model	**Geologic model**	Exists
	Coring	Will be carried out after injection	**Seismic**	Not known
	Other technologies	Development and construction of a bailer for sampling CO_2-rich fluids during mineral carbon storage		

Project context

The CarbFix project is the first fully integrated project to store CO_2 in basaltic rock. The project is to capture CO_2 from natural steam at Reyklavik Energy Hellisheidi geothermal plant and to re-inject it, after dissolution in water, onto a porous lava flow at a depth of approximately 500m (1650 ft) at a location 3kms southwest of the plant.

The project is a European-US collaboration involving Reykjavik Energy (a public utility), The University of Iceland, the University of Toulouse and Columbia University, New York.

The pilot injection is run by Reykjavik Energy and explores the mineralogical storage of CO_2, whilst minimising potential health, safety and environmental risks of sequestration.

Aims of the project

The CarbFix project aims to optimise industrial methods for storing CO_2 in basaltic rocks through in situ mineral carbonation: basaltic rocks reacting with carbonic acid to provide permanent storage. A combined program consisting of field scale injection of CO_2 charged waters into basaltic rocks, laboratory based experiments, studies of natural analogues and state of the art geochemical modelling is being carried out. A second aim of this research project is to generate the human capital and expertise to apply the advances made in this project in the future.

Ownership and liability

CarbFix is owned by Reykjavik Energy, the University of Iceland, Columbia University in New York and CNRS in Toulouse. Reykjavik Energy owns and operates all infrastructures at the injection sites (wells, pipelines etc.) while the land is owned publically. OR has presented the CarbFix project to all relevant parties and required all licenses necessary for the pilot injection.

Regulatory and approval conditions

The project was supported in a positive statement for the CO_2 injection and the use of the tracers, sulfur hexafluoride (SF_6), trifluormethylsulphur pentafluoride (SF_5CF_3), amidorhodamine G dye and radiocarbon ^{14}C by the Environmental Agency and the Icelandic Radiation Safety Authority. The project was granted an operation licence for the CO_2 injection by the Municipality of Olfus in 2010.

Pre-injection geological database and site characterisation

A background field characterisation study at the injection site and in the target reservoir was carried out between 2006 and 2011. Different monitoring methods including tracer tests using 1) sodium fluorescein and 2) sulfur hexafluoride (SF_6) and sodium fluorescein were proven valuable during baseline studies of groundwater flow and reservoir volumes. These will be continued after CO_2 injection. Water well samples have been collected regularly from all monitoring and injection wells since 2007.

Chemical scenario modelling has been conducted, as well as a three dimensional reactive transport model that simulates hydrology and mineral alteration associated with the CO_2 injection. The 3D reactive transport model was developed using TOUGH2, iTOUGH2 and TOUGHREACT. Fluid-rock reactions were coupled to the calibrated hydrology model using TOUGHREACT and predictive mass transport and reactive transport simulations were carried out for both a 1200-tonnes pilot CO_2 injection and a full-scale 400,000-tonnes CO_2 injection scenario. CO_2 sequestration rate is predicted to range between 1200 and 22,000 tonnes/year in both scenarios.

The three dimensional CarbFix numerical model has proven to be a valuable tool in simulating different injection and pumping schemes by showing what effect different pumping scenarios have in transport and distribution of injected CO_2. Reactive transport simulations furthermore indicate basalts to comprise ideal geological CO_2 storage formations.

Source of CO_2

CO_2 is captured as flue gas from the Hellisheidi geothermal power plant and is of magmatic origin.

Transport of CO_2

The CO_2 is transported in a 3 km long pipeline to the injection site. There, CO_2 is dissolved in water at depth during injection, resulting in a single fluid phase entering the storage formation. Groundwater for the injection is obtained from a well located upstream from the injection site.

Additional project details

The CO_2 captured at the Hellisheidi geothermal power plant pilot gas separation plant is transported to the injection site where it is fully dissolved in water during injection, resulting in a single fluid phase entering the storage formation. The CO_2 charged water is reactive and will dissolve divalent cations from the rock, and it is predicted to combine with the dissolved carbon to form solid carbonate minerals. Field data, such as calcite rich caprocks overlying the high-temperature reservoir suggest that mineral CO_2 sequestration already plays an important role in the evolution of the Hellisheidi geothermal system. Injecting and precipitating CO_2 in nearby formations with the objective of imitating and accelerating this natural CO_2 sequestration process should therefore be considered as an environmentally benign process.

The project is designed to inject approximately 2,000 tons of CO_2 per year, but there is the potential to upscale if mineral carbonation proves to be successful as Hellisheidi power plant annually emits some 40,000 tons CO_2.

First injection tests were carried out in 2011 using commercially bought CO_2. The objective of the test was to synchronise the injection system, evaluate the injection technology, identify and remedy any potential technical problems associated with operating the experiment. The injection test was a success and confirmed complete dissolution of CO_2 during injection.

Operational problems in the pilot gas separation station have caused problems since 2010 causing delay of CO_2 delivery to CarbFix. As a consequence, 175 tons of commercially bought CO_2 from a nearby geothermal well were injected over a 6 week period early 2012. The injection was a success and monitoring results from observation wells are very promising. Continuous injection of gas from Hellisheidi power plant commenced in June 2012 and a full pilot scale CCS cycle is now up and running at the power plant.

Stakeholder engagement

From the beginning, the CarbFix group has stressed the importance of sharing the generated knowledge with the scientific/engineering community as well as with the public. Annual reports, which include a description of project progress, new developments, and budget information, are available on the project website (www.carbfix.com). Results are regularly presented at conferences and meetings as well as in peer reviewed scientific journals. A large international public outreach forum was held at Hellisheidi Power Plant in 2009 and another one is planned in 2014. CarbFix maintains a press office which writes press releases to support media coverage. Among other outreach and dissemination activities are:

- Development and publication of educational material for children regarding a) climate change and the challenges it poses and, b) CarbFix as a contribution to the solution.
- On-site demonstration and education.
- Market research and business plan.
- Exploitation plans and reports.

Risk assessment process

A comprehensive risk assessment was carried out during the construction of experimental apparatus. An assessment was carried out both on frequency and severity of possible incidents affecting workers attending the experiment as well as the environment. The risk assessment was composed of three sections:

1. System analysis
2. Diagnosis of possible accidents
3. Assessment of probability and consequences of accidents

Possible accidents were identified from blueprints, conversations with designers of the experiment and from gained experience through the operation of the injection system. Hence the risk assessment is revised during the injection project. All steps of operation and maintenance were assessed and a standard operating procedure to all tasks was devised accordingly.

Significant learnings from the project

- Dissolving CO_2 in water during its injection into the subsurface greatly increases the security of geologic carbon storage by avoiding the need to rely on structural/sedimentary trapping mechanisms. Much of the security risk associated with geologic storage of CO_2 stems from its buoyancy. Gaseous and supercritical CO_2 are less dense than surrounding formation waters providing a driving force for it to escape back to the surface via fractures, or abandoned wells. This buoyancy can be eradicated by dissolving CO2 into water prior to, or during its injection into the subsurface. In CarbFix, CO_2 is dissolved into water during its injection into a rock formation leading to its geologic solubility storage in just a few minutes. Geologic storage will hence be dominated by solubility trapping until a time when mineral trapping occurs.
- For this purpose of CO_2 dissolution, the CarbFix group developed a new injection system that is installed in the injection well. CO_2 at 25 bar and groundwater from a nearby well are injected together. The CO_2 gas is carried down to a depth of ~500 m by the co-injected groundwater, where it enters the target storage formation fully dissolved. At these conditions, the CO_2 is at a pressure of 25 bar and the resulting pH is ~3.7.
- Laboratory experiments and reactive transport modelling indicate basalts to comprise ideal geological CO_2 storage formations as water-rock reactions lead to the formation of thermodynamically stable carbonate minerals which are stable over geologic time scales. CO_2 mineral sequestration in basalts is thus likely to be a permanent storage method.
- Capturing CO_2 from other geothermal gases (H_2S, H_2, CH_4, Ar) proved to be a greater challenge than previously anticipated. Reykjavik Energy has, however, overcome many obstacles in this matter and a fully operational pilot scale CCS cycle became operational in 2012.
- For the purpose of monitoring the CO_2 storage in the target basalt formation, the CarbFix group designed and tailored a monitoring and verification system specifically for in situ mineral carbonation. Since CO_2 is fully dissolved in water, standard geophysical monitoring techniques, such as 2D/3D seismic surveys or vertical seismic profiling (VSP) cannot be applied. Our approach is to use geochemical monitoring techniques, which are useful for directly monitoring the movement of CO_2 in the subsurface. Conservative tracers, such as trifluormethylsulphur pentafluoride (SF5CF3) and acid red dye (amidorhodamine G) are mixed into the gas and water stream at the CarbFix site to monitor and characterise the physical transport processes of advection and dispersion of the injected fluid. Furthermore, the injected CO_2 is tagged with radiocarbon (14C) by adding 14C to the water stream. The rationale behind using 14C is twofold. First, all natural carbon in the deep aquifers is generally free of 14C because of the long residence time of the groundwater and the relatively short half-life of 14C (5,730 years). Second, 14C is a reactive tracer, which means that its ratio to carbon in the groundwater will change as a result of dissolution and precipitation of carbonate minerals. Thus, if mineral carbonation occurs after the injection of CO_2, it can be monitored and verified by measuring the isotopic composition of reservoir fluid and rock samples with mass spectrometry.
- Monitoring of elemental chemistry and tracers is required to evaluate the evolution of the fluid geochemistry and degree of CO_2 mineralisation during its injection into the subsurface. Development and construction of a syringe-like bailer for sampling CO_2-rich fluids during mineral carbon storage has been carried out within CarbFix to avoid degassing during sampling, which is a common feature of commercial groundwater samplers.

Development of complex 3D hydrological and reactive transport models has proven to be a valuable tool with respect to decision making within CarbFix. Hydrological models have been used for optimising injection and pumping schemes at the CarbFix injection site and reactive transport models to estimate the mineralisation capacity of the basalts at Hellis

PROJECT SUMMARY

Project summary:
The CarbonNet Project investigating potential for multi-user network.

Total cost of project:
Current phase, $100 million

Project organisation:
Victorian Government, Department of State Development, Business and Innovation (DSDBI)

Location:
Gippsland Region, Victoria, Australia

Project type:
Large scale – deep saline aquifer

Year of first injection:
To be decided

Project scale:
Anticipated CO2 injection of 1-5 million tonnes per annum with the potential to increase

Current status:
Feasibility and commercial definition stage underway

Type and depth of reservoir:
Saline aquifer, depth (To be determined)

Type of seal:
Lakes Entrance Formation

PROJECT DETAILS

	Project operator	VIC Government, DSDBI	**Project contact phone**	+613 9658 4206
	Project contact	Richard Brookie	**Project contact email**	Richard.brookie@dpi.vic.gov.au
	Project location	Gippsland Region, Victoria, Australia	**CO_2 source**	Source yet to be confirmed.Several large scale sources in the Gippsland Region
	Injection site coordinates	To be determined	**CO_2 transport/delivery**	To be determined
	Project planning start	2010	**Injection rate**	1-5 million tonnes per annum
	Duration of injection	25 years	**Injection pressure**	To be determined
	Planned injection volume	1-5 million tonnes per annum	**Total volume injected**	25 million tonnes
	Reservoir porosity	To be determined	**Reservoir permeability**	To be determined
MONITORING	**Seismic monitoring**	To be decided	**Gravity studies**	To be decided
	Water monitoring	To be decided	**Pressure logging**	To be decided
	Soil monitoring	To be decided	**Thermal logging**	To be decided
	Atmospheric monitoring	To be decided	**Wireline logging**	To be decided
	Ecological monitoring	To be decided	**Observation well**	To be decided
	Tracer analysis	To be decided	**Geochemical research/Fluid sampling**	To be decided
	Electromagnetic	To be decided	**InSAR**	To be decided
RESERVOIR STUDIES	**Reservoir modelling**	yes	**Geologic model**	Developed
	Coring	Cores available from a large number of wells in project area	**Seismic**	yes
	Other Technologies	To be decided		

Project context

This project was selected as the second Commonwealth supported flagship project in Australia. The project is in the feasibility and commercial definition stage and as such, has yet to confirm project details regarding injection site, source and monitoring verification assessment plans or detailed characterisation details. The project has undertaken extensive reservoir modelling and screening. .

Aims of the project

The long term objective of the CarbonNet project is to establish the a world class, large scale, multi user carbon capture and storage network capable of sequestering 1-5 million tonnes of CO_2 a year, with the potential to increase capacity over time. At this stage the intention is to identify and appraise a suitable site in the offshore Gippsland Basin.

Ownership and liability

The project is jointly funded by the Australian Government and the Victorian Government and is managed by the Victorian Department of State Development, Business and Innovation.

Regulatory and approval conditions

Several key pieces of legislation underpin geological CCS processes in Victoria, including:

- Victoria's Greenhouse Gas Geological Sequestration Act 2008 (GGGS)
- Victoria's Offshore Petroleum and Greenhouse Gas Storage Act 2010
- The Commonwealth's Offshore Petroleum and Greenhouse Gas Storage Act 2006

Separate Victorian and Commonwealth legislation will regulate carbon storage activities offshore in state and commonwealth waters.

Pre-injection geological database and site characterisation

An extensive review of existing and new 2D and 3D seismic data has been undertaken by CarbonNet.

Source of CO_2

There are a number of very large sources of CO_2 in the Gippsland Region,.

Transport of CO_2

The long term objective of the project would require a pipeline.

Additional project details

CarbonNet is a strategic long term project investigating the potential for establishing the infrastructure necessary for large scale storage of CO_2 in the Gippsland Basin. The Basin has been identified as one of the best storage opportunities in Australia with a capacity of several billion tonnes of CO_2.

Stakeholder engagement

There has been ongoing engagement with representatives of the Gippsland community by CarbonNet and the State Government, particularly in the Latrobe Valley region.

Significant learnings from the project

- Developing a large scale, multi user CCS project concept is complex and time consuming.
- The offshore Gippsland Basin has very promising structures for long term storage of CO_2.

PROJECT SUMMARY

Project name: Development of China's Coalbed Methane Technology/CO_2 Sequestration Project	**Total cost of project:** $8 million CDN
Project organisation: Alberta Research Council (Now: Alberta Innovates-Technology Futures)	**Location:** South Qinshui Basin, Shanxi Province, China
Project type: Enhanced Coalbed Methane	**Year of first injection:** 2004
Project scale Small scale (192 t)	**Current status:** Project completed and final report submitted on March 31, 2007
Type and depth of reservoir: Anthracitic coal, 472 meters depth	**Type of Seal:** Silty mudstone/mudstone roof of 3.7 meters

	Project operator	China United Coalbed Methane Corp.	**Project contact phone**	+ 587 984 5269
	Project contact	Sam Wong	**Project contact email**	swongccst@gmail.com
	Project location	Shanxi Province, China	**CO_2 source**	Zhongyuan Oil Field
	Injection site coordinates	35°29'24"- 35°57'29"N, 112°15'53"–112°58'15" E	**CO_2 transport/delivery**	Truck
	Project planning start	2002	**Injection rate**	15 tonnes/day
	Duration of injection	13 days	**Injection pressure**	BHP 1.5 to 6.7 MPa 13 injection & soak cycles
	Planned injection volume	200 metric tonnes	**Total volume injected**	192 metric tonnes
	Reservoir sorptivity	0.02$m^3 CO_2$ per kg coal	**Reservoir permeability**	12 md
MONITORING	**Seismic monitoring**	Not performed	**Gravity studies**	Not performed
	Water monitoring	Not performed	**Pressure logging**	Wellhead and downhole
	Soil monitoring	Not performed	**Thermal logging**	Wellhead and downhole
	Atmospheric monitoring	Not performed	**Wireline logging**	Not performed
	Ecological monitoring	Not performed	**Observation well**	No observation well
	Tracer analysis	Natural	**Geochemical research/Fluid sampling**	Produced gas/water analysis
	Electromagnetic	Not performed	**InSAR**	Not performed
RESERVOIR STUDIES	**Reservoir modelling**	History match of micro-pilot; multi-well pilot design; and commercial prediction	**Geologic model**	Project created
	Coring	None; used pre-existing well	**Seismic**	Existing commercial data
	Other technologies	Not performed		

Project context

This project was funded by the Canadian International Development Agency (CIDA) and the Chinese Ministry of Commerce (MOFCOM). The project was designed to transfer technology to China for enhanced production of CBM and storage of CO_2 by a micro-pilot huff and puff test and subsequent assessment to predict commercial potential.

Aims of the project

The project aims to demonstrate enhancement, by injection of carbon dioxide, coalbed methane recovery factors and production rates to an economic rate, by utilising the greater affinity that coal has for CO_2 compared to methane, through a single well test. A secondary aim of this project is to demonstrate the potential to reduce greenhouse gas (GHG) emissions by subsurface injection (storage) of carbon dioxide into coalbeds with concomitant production of coalbed methane.

Ownership and liability

The project and land are owned by China United Coalbed Methane Corporation. Liability of the project lies with China United Coalbed Methane Corporation.

Regulatory and approval conditions

China United Coalbed Methane Corporation obtained these through MOFCOM. Permit was for a single well test, injection of 200 tonnes of CO_2, soak and production of CO_2 and CH_4.

Pre-injection geological database and site characterisation

A geological regional assessment was completed of 6 coal basins and their coal fields. Available mining data including gas content, permeabilities, sorptivity and gas production data which were used to assess CBM resource/CO_2 storage potential, CBM production potential, CO_2 supply potential, data availability, and market potential to rate the coal fields for pilot testing. Site visits were made to the top three sites to finalise the ranking.

Source of CO_2

Frac (industrial) grade CO_2 was purchased from the Zhongyuan Oil Field.

Transport of CO_2

The CO_2 was transported by truck from the supplier 500 km directly to the injection site.

Additional project details

The micro-pilot was the first of three proposed field tests. The data from the micro-pilot performance was used to design a multi-well pilot and to predict the economic potential for a commercial demonstration.

Stakeholder engagement

The Project delivered 18 training courses (including the two high level study tours) in China and Canada, covering all aspect of CBM and ECBM technologies. 299 CUCBM and Chinese staff (50 females, or 17%) were trained in China and another 53 senior CUCBM managers (18 females, or 30%) were trained in Canada. It is noted that some CUCBM trainees were trained at more than one training course. Given the low percentage of women in the CBM sector in China (as in Canada) it can be considered that the project succeeded in promoting women in training activities.

Risk assessment process

Risk assessment of the micro-pilot project was addressed during design of the project and training of Chinese personnel involved. Canadian experts were on site during all critical periods of the micro-pilot CO_2 injection, soak and production periods. Design of the multi-well pilot centered around the history match of the micro-pilot to predict the response of the multi-well pilot. Only economic risk was evaluated for the conceptual design of the commercial demonstration.

Significant learnings from the project

- Enhancement of coalbed methane recovery and storage of CO_2 is feasible in the anthracitic coals of Shanxi Province.
- The recommendation is to proceed to a full scale multi-well pilot test at south Qinshui.
- The prospect is good for technology to be applied to other coal basins in China.
- The learnings for progressing through geological assessment, to micro-pilot, to designing multi-well pilots, to commercial demonstrations are contained in a book published in both English and Chinese "**Recommended Practices for CO_2 - Enhanced Coal Bed Methane Pilot Tests in China"**, Bill Gunter, Sam Wong and Xiaohui Deng, Rudy Cech, Sorin Andrei and Doug Macdonald, ISBN 978-7-116-05833-0, 275 pages (2008).

PROJECT SUMMARY

Project name:
CO2CRC Otway Project (Stage 2A,B)

Project organisation:
CO2CRC

Project type:
Deep saline aquifer, field test of residual and dissolution trapping

Project scale:
Small scale (150 t)

Type and depth of reservoir:
Sandstone, 1395m depth

Total cost of project:
USD $20,644,000 (AUD $20 million) (April 16, 2013)

Location:
Near Port Campbell, Southwest Victoria, Australia

Year of first injection:
2011

Current Status:
Injection completed in 2011; other experiments planned at the site for 2013-2014

Type of Seal:
Mudstone

PROJECT DETAILS

	Project operator	AGR	**Project contact phone**	+61261201600
	Project contact	CO2CRC, Rajindar Singh	**Project contact email**	rsingh@co2crc.com.au
	Project location	Port Campbell, Victoria, Australia	**CO_2 source**	Food grade from the Boggy Creek CO_2 facility of BOC
	Injection site coordinates	38°33'34"S, 142°52'40"E	**CO_2 transport/delivery**	Truck
	Project planning start	2008	**Injection rate**	30 tonnes/day (CO_2)
	Duration of injection, if known	5 days (total test lasted 4 months)	**Injection pressure**	14 MPa
	Planned injection volume	Total of 150 tonnes of CO_2 plus 450 tonnes of formation water	**Total volume injected**	150 tonnes CO_2 plus 450 tonnes of formation water
	Reservoir porosity	28%	**Reservoir permeability**	2.1 darcies
MONITORING	**Seismic monitoring**	VSP, microseismic	**Gravity studies**	Not performed
	Water monitoring	Downhole sampling	**Pressure logging**	Wellhead and downhole
	Soil monitoring	CO_2 soil flux monitoring	**Thermal logging**	Well head and downhole
	Atmospheric monitoring	Dedicated atmospheric towers	**Wireline logging**	Full logging suite
	Ecological monitoring	Not performed	**Observation well**	No observation well
	Tracer analysis	Kyrpton, xenon, Esters	**Geochemical research/Fluid sampling**	Downhole sampling using U tube configuration
	Electromagnetic	Not performed	**InSAR**	Not performed
RESERVOIR STUDIES	**Reservoir modelling**	Eclipse	**Geologic model**	Petrel
	Coring	Extensive coring of the Paaratte Formation	**Seismic**	3D seismic conducted at the site as part of Stage 1 and will be conducted as part of Otway stage 2C
	Other Technologies	Microbial		

Project context

The CO2CRC Otway site had previously been used for the injection of 65,445 tonnes of CO2-rich mixture into the Waarre-C Formation (Stage 1). For this earlier stage, injection was via the CRC-1 well with injection at a depth of 2,003 – 2,014 m TVDSS (true vertical depth below mean sea level). The next stages at the CO2CRC Otway site involved drilling a new well, CRC-2 (CO2CRC Otway Stage 2A) and the residual saturation and dissolution test (CO2CRC Otway Stage 2B), conducted in 2011. Provisions have been made for possible future tests at the site with a Stage 2C proposed.

Aims of the project

Residual and dissolution trapping are important mechanisms for secure geological storage of carbon dioxide. When appraising a potential site, it is desirable to have accurate field-scale estimates of the proportion of trapping by these mechanisms. For this purpose a short single-well test was conceived that could be implemented before large-scale injection. To test this concept in the field, a residual saturation and dissolution test sequence was conducted at the CO2CRC Otway site during 2011. The test involved injection of 150 tonnes of pure carbon dioxide followed by 454 tonnes of formation water to drive the carbon dioxide to residual saturation. A variety of methods for measuring saturation were applied to the injection zone so the results could be compared.

Ownership and liability

CO2CRC owns the petroleum tenements relating to the site plus the wells and related facilities, and has formal agreements in place with landowners for access to the site and adjacent areas. Short term liability was covered through insurance and additional guarantees by industry participants. Long term liability will de facto be held by the state once the tenements are returned to the state.

Regulatory and approval conditions

The field experiment was undertaken under the R&D provisions of the Victorian EPA, with the cooperation of the Department of Primary Industries, the regulator of petroleum related activities. It was also necessary for Southern Rural Water, the local water company responsible for aquifer management to approve the project.

Pre-injection geological database and site characterisation

A great deal of characterisation of the site was undertaken as part of CO2CRC Otway Stage 1; however, this Stage 2 A-B was focused on a shallower unit which was not well known prior to the work of CO2CRC and therefore it was necessary to drill a new well and to undertake an extensive program of coring and geological modelling. The residual saturation and dissolution test involved injection into the Paaratte Formation at between 1392-1399 m TVDSS. The Paaratte Formation represents a saline aquifer that is typical of many prospective geological systems under consideration for future commercial-scale CO_2 storage. It has no apparent structural closure and is lithologically heterogeneous. Deposited in a shallow marine deltaic setting with dominant fluvial and tidal processes, the preserved sediments comprise intercalations of medium to high permeability sands thinly interbedded with carbonaceous mud-rich lithologies, and are over printed with digenetic carbonate cement layers which serve as seals of varying quality. The injection interval was selected within a relatively homogenous sandstone unit between two cemented sandstones. It has an average porosity of 0.28 and an average permeability of 2.1 darcies. The bounding cements comprise over 30% grain coating dolomite that has occluded the pore space and reduced the porosity to 0.05–0.10 and permeability to 1–10 millidarcies. This has the effect of vertically confining the injected fluid in the vicinity of the perforation interval.

Source of CO_2

Because of the nature of the field experiments it was necessary to use pure CO_2. This was obtained as food-grade CO_2 from the nearby Boggy Creek facility of Linde (BOC), which purifies CO_2 from a geological source.

Transport of CO_2

The CO_2 was transported by tanker from the Boggy Creek facility to the Otway project site approximately 1 km away, although because of the condition of the roads it was necessary for the tanker to travel approximately 10 km.

Additional project details

The CRC-2 well was completed with 0.140 m (5.5 inch) outer diameter production casing and 0.0253 m (1.0 inch) internal radius tubing. Installed downhole was an inflatable straddle packer, configured to isolate the test zone and isolate the sump area. Redundant sets of pressure/temperature gauges were installed at the top and bottom of the perforated interval, along with a fiber-optic distributed temperature sensor and heat-pulse conductors. An additional two retrievable memory gauges were installed at 900 and 1047 m TVDSS and retrieved using slickline. A U-tube sampling system was installed at the top of the perforated interval to provide representative fluid samples under in situ pressure conditions.

Prior to the test sequence, 510 tonnes of formation water were produced over 10 days. The testing started with initial characterisation of the formation without CO_2. Carbon dioxide was injected followed by further characterisation, then formation water was injected to drive the CO_2 to residual saturation, and a series of tests were implemented to measure saturation. These methods for measuring residual saturation are briefly described below.

High-quality pressure data were obtained from the downhole gauges, these data are plotted in Fig. 3. Each step involving injection or production was analysed. Prior to the CO_2 injection, the single-phase water injection and production was interpreted using conventional well test analysis for bulk permeability. This also enabled determination of the duration of wellbore storage and measurement of a negative skin resulting from the perforations. After CO_2 injection the pressure responses involve two-phase flow. Essentially this requires multi-phase well test analysis where numerical simulation is used to inverse model the reservoir response to derive the residual saturation.

On three occasions during the test sequence a reservoir saturation tool (RST) was used to log the well over a 255 m interval. Logging was conducted prior to CO_2 injection, after CO_2 injection, and after water injection at residual saturation conditions. Comparing these logging measurements allows the CO_2 saturation to be determined at each step. The tool's depth of investigation is rated at 0.25 m with a vertical resolution of 0.38 m.

Due to the low salinity of the formation water (approximately 800 ppm), thermal decay porosity (TPHI) was used as the main measurement for calculating saturation. From the logging results, residual saturation was determined to be around 0.18 in the lower half of the perforated interval and around 0.23 in the top half. An issue for the interpretation of the data was the changing fluid conditions in the wellbore as the tool had not been characterised for operating when immediately surrounded by CO_2.

A number of tracer experiments were undertaken; noble gases krypton (Kr) and xenon (Xe) were injected with water before CO_2 injection to act as non-partitioning tracers. Then Kr and Xe were injected again after residual saturation was obtained to act as partitioning tracers. Reactive tracers were also used to determine partition coefficients.

Stakeholder engagement

Good relations were maintained with the local community; engagement of a local person as liaison officer and employment of local staff where possible, was critical to this success. The 2B experiment did not involve any major seismic surveying or other intrusive activities and was of limited duration; as such it had little impact on the local community.

Risk assessment process

Risk assessment was an important part of the project and was undertaken quite rigorously before any injection occurred.

Significant learnings from the project

- The CO2CRC Otway project Stage 2B successfully injected CO_2 and drove it to residual saturation.
- Several measurements of residual trapping were deployed, each with a different volume of investigation.
- All of the methods deployed could be used to measure residual trapping, although some of the methods would benefit from further development and analysis.
- The importance and duration of thermal effects has been identified as an important component for detailed study.
- More than one method should be used for the most accurate determination of residual trapping; each technique offers advantages and limitations.

PROJECT SUMMARY

Project name: CO2CRC Otway Project (Stage 1)	**Total cost of project:** AUD$ 40,000,000
Project owner: CO2CRC	**Location:** Near Port Campbell, southwest Victoria, Australia
Project type: Research - Depleted gas field	**Year of first injection:** 2008
Project scale: Small scale (65,445 t)	**Current status:** Injection completed in September 2009; monitoring is ongoing
Type and Depth of reservoir: Sandstone, >2000m	**Type of seal:** Mudstone, structural fault bound trap

PROJECT DETAILS

	Project operator	AGR/Process Group	**Project contact phone**	(02) 6120-1600
	Project contact	CO2CRC, Rajindar Singh	**Project contact email**	rsingh@co2crc.com.au
	Project Location	Port Campbell, Victoria, Australia	**CO_2 Source**	Natural accumulation, mixed gas
	Injection site coordinates	Naylor Field UTM, GDA94: Easting 657634.24, Northing 5733850.997	**CO_2 transport/delivery**	Pipeline (1.4km long)
	Project planning start	2004	**Injection rate**	150 tonnes/day
	Duration of injection	528 days	**Injection pressure**	From 17.9 to 19.3 MPa
	Planned injection volume	Up to 100,000 t	**Total volume injected**	65,445 t
	Reservoir porosity	6-28% (14%)	**Reservoir permeability**	0.01-6000 mD (1105 mD)
MONITORING	**Seismic monitoring**	4D surface, VSP, micro, HRTT	**Gravity studies**	Not performed
	Water monitoring	Dedicated shallow wells	**Pressure logging**	Wellhead and downhole
	Soil Monitoring	CO_2 soil flux monitoring	**Thermal logging**	Wellhead and downhole
	Atmospheric monitoring	Dedicated atmospheric towers	**Wireline logging**	Full logging suite in injection well
	Ecological monitoring	Not known	**Observation well**	Dedicated well (pre-existing production well)
	Tracer analysis	CD4, SF6, Krypton	**Geochemical research/Fluid sampling**	Downhole fluid sampling from 3 points in observation well
	Electromagnetic	Not performed	**InSAR**	Not performed
RESERVOIR STUDIES	**Reservoir modelling**	ECLIPSE	**Geologic model**	Petrel
	Coring	Reservoir and seal cored in Injection well	**Seismic**	4D seismic acquired
	Other technologies	core flooding (SCAL), Microtomography, Pulsed Neutron using Reservoir Saturation Tool (RST)		

Project context

The Otway 1 project was conceived as an opportunity to demonstrate safe and secure geological storage of CO_2 under Australian conditions. Whilst it was recognised that scientific lessons learned from storage projects undertaken overseas could be fairly readily translated to Australian geological condition, this did not apply to public perceptions or community attitudes to the technology. Nor did it extend to the regulatory conditions under which it was necessary to operate in Australia. Therefore, there was a real need to undertake a significant storage project in Australia. In addition, the Australian climatic conditions under which the project was to be undertaken would need to be considered when developing a monitoring program.

Part of the approach taken to developing the proposal was to attempt to undertake it at what was considered to be a commercially significant scale, defined for the purposes of the project as 50-100,000 tonnes of CO_2. Ideally the CO_2 would have been sourced from a power station or some other major industrial source, but it was recognised that this would have resulted in the project being delayed for at least five years and probably longer and therefore alternative sources such as food grade CO_2 were considered. However in 2003 -2004, an opportunity arose to purchase a high-CO_2 natural gas well in the Otway Basin. This was taken because it provided a much earlier opportunity to get the project underway than any other major source offered and also because the area offered excellent storage opportunities. From a strategic point of view it also offered opportunities for other experiments in the future. Finally and critically, the source of the CO_2 and the depleted gas well could be purchased from a willing seller. It was therefore decided to go ahead with the CO2CRC Otway Project.

Aims of the project

The aim of this project was to demonstrate safe transport, injection and geological storage of carbon dioxide under Australian conditions and to effectively monitor the stored CO_2.

Ownership and liability

The Project was undertaken by CO2CRC Ltd (previously named CO2CRC Pilot Project Ltd -CPPL) on behalf of the CO2CRC research consortium of Australian and international industry, government and research organisations (see www.co2crc.com.au), with financial support from the members of CO2CRC, the Australian federal government, the Victorian state government, and the US Department of Energy.

The project is an endorsed CSLF Project. The Project owns the petroleum tenements relating to the site plus the wells and related facilities, and has formal agreements in place with landowners for access to the site and adjacent areas. Short term liability was covered through insurance and additional guarantees by industry participants. It is anticipated that long term liability will de facto be held by the state once the tenements are returned to the state.

Regulatory and approval conditions

Not known.

Pre-injection geological database and site characterisation

The CO2CRC Otway site comprises a small economically depleted gas field and a high CO_2 gas field (Buttress). Pre-existing data for reservoir characterisation was available to the researchers and included a 3D seismic survey over the structure and basic downhole logs from the single discovery/production well (Naylor-1). In addition there was publically available data for a number of boreholes in the adjacent area together with a regional seismic grid.

Some production data was also available for Naylor-1 which allowed history matching to calibrate the dynamic reservoir modelling and estimate the total storage capacity of the Naylor structure.

Source of CO_2

The carbon dioxide is obtained from the Buttress No. 1 gas well, located approximately 1.4 km from the injection site. The gas is a mixture of carbon dioxide (75.4 mol %) and methane (20.5 mol %) plus other minor components.

Prior to transport, heavy waxes and some water were removed from the gas; the gas was then compressed to a liquid prior to transport.

Buttress reserves were estimated to be at least 95,000 tonnes, at the P90 level, which was deemed adequate for the proposed project. In the event, production of the gas over an extended period indicated that total gas reserves were much larger.

Transport of CO_2

The CO_2 was transported (in liquid form) a distance of approximately 1.4km, via stainless steel piping.

Additional Project details

A critical initial stage in this project was the acquisition by the CO2CRC of two petroleum titles covering a small unproduced CO_2 rich gas accumulation (Buttress) and a small depleted natural gas field (Naylor) both having suspended production wells. These provided the source for the CO_2 used in the research together with the monitoring well to demonstrate the movement of the CO_2 within the depleted structure.

Very extensive site characterisation and risk assessment was undertaken by CO2CRC prior to injection, using a variety of data sources. In 2007 a dedicated injection well (CRC-1) was drilled to a total depth of approximately 2200m (below sea level), some 300m down dip of the crest of the Naylor structure. Injection of CO_2 commenced in March 2008 and was concluded in September 2009, by which time a total of 65,445 tonnes of gas had been injected into the Naylor depleted gas field.

The CO_2 was injected and stored in the Cretaceous Warree C Formation at a depth of approximately 2000m. At the site, the reservoir is bound on three sides by faults which juxtapose the sandstone with the overlying Belfast Mudstone seal that provides a well defined structural trap for the stored CO_2. The storage formation appears to have been deposited under coastal-to-near-shore marine conditions. It has a high porosity (up to 28%) and multi-Darcy permeability. Extensive static and dynamic modelling was undertaken prior to any CO_2 being injected. Injection was into the water leg of the Naylor field which had residual methane (~20%) and a small gas cap remaining after production ceased.

The injection pressure was 17.9-19.3 MPa at a temperature of 63^0C; Injection of CO_2 was concluded when the CO_2 reached the monitoring well and the gas-water interface was below the level of the sampling equipment.

Stakeholder engagement

Overall, good relations were maintained with the local community; engagement of a local person as liaison officer and employment of local staff where possible, was critical to this success. The need to undertake repeat 3D seismic surveys posed the most difficult challenge, because of the impact of the survey on agricultural land and required careful negotiation with landowners.

Significant learnings from the project

- The project successfully (and safely) demonstrated geological storage of CO_2 at a commercially significant scale to a large number of Australian and international stakeholders.
- Overall, the project achieved its scientific and monitoring objectives, with successful sampling of reservoir fluids under sub-surface pressure and temperature conditions being especially notable.
- Observations of the plume migration and reservoir storage capacity matched the predictions from the static and dynamic models adding confidence to predictive tools.
- The project was also able to demonstrate the value of atmospheric monitoring and the need for extensive base line monitoring.
- As anticipated, it was not possible to detect injected CO_2 using seismic methods because of the presence of residual methane in the depleted gas field.
- Early and ongoing community consultation was very important to the success of the Project

PROJECT SUMMARY

Project name:
Callide Oxyfuel Project (proposed Stage 2 transport and storage)

Project organisation:
CS Energy

Project type:
Deep saline aquifer/depleted oil field reservoirs

Project scale:
Small scale (<60,000 t anticipated)

Depth and type of reservoir:
To be determined, depleted oil/gas field

Total cost of project:
Not announced

Location:
Near Biloela in Central Queensland

Year of first injection:
Not known

Current status:
Feasibility study underway

Type of seal:
Not known

PROJECT DETAILS

	Project operator	CS Energy	**Project contact phone**	07 3222 9838
	Project contact	Chris Spero	**Project contact email**	cspero@csenergy.com.au
	Project location	Callide Valley, Qld, Australia	**CO_2 source**	Callide A oxyfuel plant
	Coordinates	24°20′50″S 150°36′31″E	**CO_2 transport/delivery**	pipeline
	Project planning start	2012	**Injection rate**	Approx 10,000 tonnes CO2 per annum
	Duration of injection	Five years	**Injection depth**	To be determined
	Planned injection volume	Total of 60,000 tonnes	**Injection pressure**	To be determined
	Reservoir permeability	To be determined	**Reservoir porosity**	To be determined
MONITORING	**Seismic monitoring**	To be decided	**Gravity studies**	To be decided
	Water monitoring	To be decided	**Pressure logging**	To be decided
	Soil monitoring	To be decided	**Thermal logging**	To be decided
	Atmospheric monitoring	To be decided	**Wireline logging**	To be decided
	Ecological monitoring	To be decided	**Observation well**	To be decided
	Tracer analysis	To be decided	**Geochemical research/Fluid sampling**	To be decided
	Electromagnetic	To be decided	**InSAR**	To be decided
RESERVOIR STUDIES	**Reservoir modelling**	yes	**Geologic model**	yes
	Coring	Some cores available in project region.	**Seismic**	yes
	Other technologies	Not known		

Project context

The Callide Oxyfuel project's primary objective is the retrofitting of oxyfuel combustion technology to an existing 30Mw boiler. That phase of the project has now been successfully commissioned and progress into stage 2 has been decided upon, which will involve the transport and storage of CO2 produced at the Callide A facility.

Aims of the project

The aim of the project is to demonstrate the integrated CCS process using oxyfuel combustion as the source of the CO2. Stage 1 was concerned with oxyfuel; Stage 2 (which has just been announced) is concerned with transport and storage and is at the early feasibility stage.

Ownership and liability

CS Energy heads a partnership with IHI Corporation, J Power, Mitsui, Schlumberger and Xstrata. As a storage site has yet to be confirmed, the issue of land ownership has yet to be addressed. The liability arrangements are not known.

Regulatory and approval conditions

Geological storage of CO_2 is permitted in Queensland under specific CCS legislation.

Pre-injection geological database and site characterisation

The region around Biloela has been explored for oil and gas and this provides an extensive geological database.

Source of CO_2

The source of CO_2 will be most likely from Callide A oxyfuel plant.

Transport of CO_2

Transport of CO_2 will be most likely via pipeline.

Stakeholder engagement

There has been engagement with the community by CS Energy and the Queensland State Government.

Significant learnings from the project

- Learnings to date have been solely in the area of retrofit of oxyfuel combustion technology.
- Learnings of transport and storage will be gained during stage 2.

PROJECT SUMMARY

Project name: CSEMP (CO_2 Storage and Enhanced Methane Production)	**Total cost of project:** USD $2,928,000 (CDN $3 million) (April 16, 2013)
Project organisation: Alberta Research Council (Now: Alberta Innovates -Technology Futures)	**Location:** South Buck Lake, Alberta, Canada
Project type: Enhanced Coalbed Methane	**Year of first injection:** 2006
Project scale: Small (1000 t)	**Current status:** Project completed
Type and depth of reservoir: Lower Ardley high volatile B bituminous coal (Silkstone & Mynheer members), 420 meters depth	**Type of Seal:** 1 to 30 meters of shale overlain by channel sands

PROJECT DETAILS

	Project operator	Suncor, EnerPlus	**Project contact phone**	+780 450 5405
	Project contact	John Faltinson	**Project contact email**	John.Faltinson@albertainnovates.ca faltinj@shaw.ca
	Project location	Alberta, Canada	**CO_2 source**	Food grade
	Injection site coordinates	54°39'03.89" N, 115°02'30.43" W	**CO_2 transport/delivery**	Truck
	Project planning start	2003	**Injection rate**	40-45 tonnes/day
	Duration of injection	17 days	**Injection pressure**	1.7 to 8.1 MPa
	Planned injection volume	30,000 tonnes	**Total volume injected**	1000 tonnes
	Reservoir sorptivity	~0.02 $m^3 CO_2$/kg coal	**Reservoir permeability**	1 to 3 md
MONITORING	**Seismic monitoring**	One 3D seismic survey pre injection. Follow-up post injection 3D survey cancelled.	**Gravity studies**	Not performed
	Water monitoring	3 dedicated shallow wells + 17 residential water wells	**Pressure logging**	Wellhead and downhole. Permanent casing gauges run in with casing at 345 (external), 405 (external) and 410 m (int. & ext.).
	Soil monitoring	Not performed	**Thermal logging**	Wellhead and downhole (see Pressure)
	Atmospheric monitoring	Baseline and controlled leaks surveys	**Wireline logging**	Not performed
	Ecological monitoring	Not performed	**Observation well**	200 meters from injector
	Tracer analysis	Natural and N2	**Geochemical research/Fluid sampling**	Produced gas/water analysis
	Electromagnetic	Not performed	**InSAR**	Not performed
RESERVOIR STUDIES	**Reservoir modelling**	History matching of micro-pilot; and prediction of multi-well pilot & commercial operation	**Geologic model**	Both regional and detailed study based on well logs of the Ardley coal and seals. Used average coal properties for modelling
	Coring	From drilled injection well	**Seismic**	Existing commercial data and baseline 3D
	Other technologies	Tiltmeter array		

Project context

This project was the fourth phase of Alberta's work on ECBM and was designed to investigate the technical and economical feasibility of using CO_2 to enhance coalbed methane production whilst also storing CO_2 in the same coal seams for shallow coals. (Phase I was a CO_2 micro-pilot and Phase II was flue gas micro-pilots, both Phases occuring in the deep coals of the Mannville Formation. Phase III was evaluating potential commercial CO_2 sources and drilling shallower coal horizons to identify another site for pilot testing of ECBM and CO_2 storage.)

The Phase IV project site (identified in Phase III) is located near Drayton Valley, Alberta. The CO_2 Storage and Enhanced Methane Production (CSEMP) Project was designed and executed by Alberta Research Council. The project was managed by Suncor Energy Inc., while the wells were owned and operated by EnerPlus Resources Fund. The project follows on from the single well injection pilot project conducted at Fenn-Big Valley in Phases I and II.

Aims of the project

The project aims to enhance, by injection of carbon dioxide, coalbed methane recovery factors and production rates to an economic rate in Alberta by utilising the greater affinity that coal has for CO_2 compared to methane. A secondary aim of this project is demonstrate the potential to reduce greenhouse gas (GHG) emissions by subsurface injection (storage) of carbon dioxide into coal beds with concomitant production of coalbed methane.

Ownership and liability

The project is managed by Suncor Energy Inc. with the Alberta Research Council as the research lead. The operator and owner of the lease and wells is EnerPlus. EnerPlus has assumed all liability for the project.

Regulatory and approval conditions

An experimental permit for the project was obtained from the Energy Resources and Conservation Board of Alberta and issued to Enerplus who are the operators of the project.

Pre-injection geological database and site characterisation

Surface and downhole 3D-3C reflection seismic surveys were completed at the enhanced coalbed-methane (CBM) production site. Baseline surveys to image the Ardley coals were conducted to gain a greater understanding of the formation prior to injection and to establish baseline data. The surveys provided an accurate depth model of the coals in the survey area and identified lateral facies changes in the coals. The project targeted the Ardley Coal Zones, around 400-450 meters deep, within the upper Scolland formation, in Alberta, Canada. Seal formations were thought to be fine layers of muds and siltstones between coal and sand facies.

Source of CO_2

The food grade CO_2 was purchased from a commercial source.

Transport of CO_2

The CO_2 was transported by truck from the supplier directly to the injection site and stored in a bullet so that a continuous injection could be performed.

Additional project details

The project consisted of two CO_2 injections. The first injection was a short injection test in 2006. This initial injection of liquefied CO_2 identified a leak through the casing (gauge threads) into a water-sand 5 meters above the coal and the test stopped. Following the resolution of the casing leak by setting a retrievable casing patch, a second injection test was run in 2007 as a multi–well phase with an offset well put on production. The injection was initiated in June 2007, starting at 38 tonnes/day increasing to 45 tonnes/day. Twelve days after beginning the injection, increased external pressure was detected by the external gauge~~s~~ in the Edmonton water sand above the Silkstone coal sand package. It was concluded that the CO_2 was leaking upwards. The injection was then suspended at 1000 tonnes of CO_2 injected. Compelling ~~E~~evidence for the second leak suggests there was a pathway~~s~~ of communication occurring outside the casing and likely though a micro-annulus between well casing and de-bonded primary cement.

Stakeholder engagement

Extensive discussions with the regulatory agencies occurred, as the target coal was close to the lower level of potable groundwater in the area. In addition, during the sampling of the 17 residential water wells for monitoring leakage, discussions of the project were had with the land owners.

Risk assessment process

Prior to the project, risk assessment was addressed in the experimental application to the regulatory body of Alberta (ERCB). During the project, the monitoring tools were designed to detect leakage at the surface and in the subsurface, for two overlying aquifers and in an overlying coal. The project was terminated after the micro-pilot, due to economic risk that the project would never be commercially viable due to the low producibility of the Mynheer coal member. The next step; the planned pilot was not executed. Consequently, the leakage issue was never resolved, although a solution was proposed.

Significant learnings from the project: were from the monitoring technologies tested

- The Project found benefits of using downhole gauges for operational monitoring as it provided: (i) Quick leak detection before significant injected fluid was transported to areas outside the target injection zone. (ii) Better pressure monitoring and detection of non-intrusive CO_2 pressure and complex phase behaviour during injection and fall-off testing. (iii) The gauges provided precise pressure monitoring during production testing. This eliminated the need for running, setting and retrieving wireline gauges or estimating via fluid levels. (iv) The gauges provided real time 24/7 remote monitoring of downhole pressure/temperature via internet with no delay (as there is with wireline gauge data).
- The tiltmeter array was able to detect ground movement associated with the injection of 1000 tonnes of CO_2.
- The 3D seismic detected an anomaly which may be related to the initial CO_2 injection.
- Atmospheric monitoring using laser instruments were more sensitive to CH_4 impurities in model releases than the CO_2.
- Shallow monitoring wells showed no changes in water levels or chemistry (including isotopes) related to the injection of 1000 tonnes of CO_2.

PROJECT SUMMARY

Project name:
East Canton Oil Field

Project organisation:
Ohio Geological Survey

Project type:
EOR

Project scale:
81 tons of CO_2 "Huff and Puff"

Type and depth of reservoir:
Silurian Sandstone

Total cost of project:
Not known

Location:
Stark County, Ohio, USA

Year of first injection:
2008

Current status:
Injection Complete

Type of Seal:
Dayton Formation ("Packer Shell") immediate overlying seal

Rochester Shale primary seal

PROJECT DETAILS

	Project operator	Ohio Geological Survey	**Project contact phone**	(614) 265-6573
	Project contact	Ronald Riley	**Project contact email**	ron.riley@dnr.state.oh.us
	Project location	Stark County, Ohio, USA	**CO_2 source**	Praxair (Food grade)
	Injection site coordinates	40°43'29"N 81°19'18"W	**CO_2 transport/delivery**	Truck
	Project planning start	2008	**Injection rate**	97 tons per day
	Duration of injection	1 day	**Injection pressure**	617 psi, maximum
	Planned injection volume	81 tons	**Total volume injected**	81 tons
	Reservoir porosity	Estimated 4% to 8%	**Reservoir permeability**	0.10 – 1.0 md
MONITORING	**Seismic monitoring**	Not performed	**Gravity studies**	Not performed
	Water monitoring	Not performed	**Pressure logging**	Not known
	Soil monitoring	Not performed	**Thermal logging**	Not known
	Atmospheric monitoring	Not performed	**Wireline logging**	Performed
	Ecological monitoring	Not performed	**Observation well**	7 observation wells
	Tracer analysis	Not performed	**Geochemical research/Fluid sampling**	From observations wells
	Electromagnetic	Not performed	**InSAR**	Not performed
RESERVOIR STUDIES	**Reservoir modelling**	History match, modelling , and simulation by Fekete	**Geologic model**	Yes, structure, isopach, porosity, permeability, Sw, and lineament maps using Geographix software.
	Coring	Not performed	**Seismic**	None
	Other technologies			

Project context

This project was a detailed reservoir characterization study to evaluate CO_2-EOR possibilities in the East Canton oil field in northeastern Ohio.

The field has produced approximately 95 million barrels (MMbbl) of oil from the Silurian "Clinton" sandstone, and had not been water-flooded. (however, there is currently an ongoing waterflood by Enervest) An estimated 10 MMbbl of remaining oil reserves could be produced through primary recovery, with estimates of up to 279 MMbbl of oil produced through CO_2-EOR. In addition, the storage capacity for CO_2 was to be estimated, with the CO_2 source planned to come from a proposed Ohio River Clean Fuels Plant (biomass and coal to liquids) in Wellsville. This coal to liquids facility operation is no longer planned.

Aims of the project

To undertake reservoir characterization of the Clinton interval (Silurian Sandstone) and to assess CO_2-EOR possibilities for the East Canton oil field.

Ownership and liability

Not known.

Regulatory and approval conditions

Not known

Pre-injection geological database and site characterisation

Regionally, the "Clinton" interval has an average gross thickness of 110 feet, existing data suggesting a fluvial-deltaic and offshore-marine depositional environment. The clastic source is from the east and is dominantly controlled by three deltaic lobes oriented east–west and southeast–northwest.

The "Clinton" interval was subdivided into five sandstone units for the purpose of geological modeling including porosity and permeability distribution.

The trapping mechanism is from stratigraphic traps formed by updip thinning and pinchout of the "Clinton" sandstone.

During the project, four cores were examined.

An extensive site database was constructed 350 digital wireline logs, completion data for 384 wells, reservoir pressure and oil property data.

Detailed reservoir characterization involved construction of 32 cross sections and 54 maps.

The information was provided to Fekete Associates, Inc for reservoir modeling and simulation.

Source of CO_2

Praxair

Transport of CO_2

Trucked in.

Additional project details

A CO_2 cyclic test ("Huff-n-Puff") was conducted on the Sikafoose-Morris #1 well in Stark County as part of the study. All data collected during this test were analyzed, interpreted, and incorporated into the reservoir characterization study and used to develop the geologic model. Eighty-one tons of CO_2 (1.39 MMCF (million cubic feet)) were injected over a 20-hour period, after which the well was shut-in for a 32-day "soak" period before production was resumed. Results demonstrated injection rates of 1.67 MMCF of gas per day, which was much higher than anticipated. Encouraging results and lessons learned from this test have resulted in a proposed larger-scale CO_2 flood (approximately 10,000 tons) to be conducted in this economically promising oil field.

Stakeholder engagement

Not known

Risk assessment process

Not known

Significant learnings from the project

While the project added to the characterization of the "Clinton" sandstone, additional data and tests are needed to refine the models and reduce uncertainty. This includes PVT and swelling test, oriented core and microseis, relative permeability, capillary pressure and wettability. A larger scale cyclic CO_2 injection was recommended.

PROJECT SUMMARY

Project name: Fenn/Big Valley	**Total cost of project:** $5 million Cdn
Project organisation: Alberta Research Council (Now: Alberta Innovates -Technology Futures)	**Location:** Fenn-Big Valley, Alberta, Canada
Project type: Enhanced Coalbed Methane	**Year of first injection:** 1998
Project scale Small scale (180 t)	**Current status:** Project complete
Type and depth of reservoir: Manville high volatile B bituminous coal, 1260 meters	**Type of seal:** Sandy shale

PROJECT DETAILS

	Project operator	Gulf Canada	**Project contact phone**	+1 780 993 5375
	Project contact	Bill Gunter (ARC)	**Project contact email**	Bill.Gunter@albertainnovates.ca
	Project location	Big Valley, Alberta, Canada	**CO_2 source**	Fertilizer plant at Medicine Hat
	Injection site coordinates	52°08'26"N, 112°44'37"W	**CO_2 transport/delivery**	Truck or compressor flue gas
	Project planning start	1996	**Injection rate**	15 tonnes/day cyclic or 25 to 50 tonnes/day continuous
	Duration of injection	4 injections: pure CO_2 (21 days); pure N_2 (1d); Flue gas of 13% CO_2 (6d) ; & a 50:50 mixture (2days)	**Injection pressure**	BHP 7.9 to 16 MPa Injection & soak cycles: 100% CO_2 =12 cycle; Continuous injection: 100% N_2, 50% CO_2, & 13% CO_2
	Planned injection volume	200 tonnes of CO_2	**Total volume injected**	180 tonnes CO_2; 8,300m^3 N_2; 40,911m^3 N_2 & 35,983m^3 CO_2; 72,000m^3 N_2 & 11,000m^3 CO_2
	Reservoir sorptivity	~0.02m^3CO_2 per kg coal	**Reservoir permeability**	1 to 4md
MONITORING	**Seismic monitoring**	Not performed	**Gravity studies**	Not performed
	Water monitoring	Not performed	**Pressure logging**	Wellhead and downhole
	Soil monitoring	Not performed	**Thermal logging**	Wellhead and downhole
	Atmospheric monitoring	Not performed	**Wireline logging**	Not performed
	Ecological monitoring	Not performed	**Observation well**	No dedicated well
	Tracer analysis	Not performed	**Geochemical research/Fluid sampling**	Produced gas/water analysis
	Electromagnetic	Not performed	**InSAR**	Not performed
RESERVOIR STUDIES	**Reservoir modelling**	Tested 5 different simulators	**Geologic model**	Treated as homogenous coal seam
	Coring	2 wells used, only 1 cored	**Seismic**	Not performed
	Other technologies	Not known		

Project context

This project consisted of a number of micro-pilot tests carried out at Fenn-Big Valley Alberta starting in 1997 into a 4 metre Manville Formation coal seam of low 1-4mD permeability.

Alberta coals, in general, have a very low permeability compared with others such as San Juan Basin coals and gas production is low. This has lead to the need for enhanced coalbed methane (ECBM) recovery technologies to improve economic recovery rates. This project was an early stage single well injection pilot test, which if successful would lead to a full scale 5-spot CO_2 injection pilot test. It was the first micro-pilot test of a pure CO_2 injection.

Aims of the project

The main objectives of this project were to reduce CO_2 emissions by injecting CO_2 into deep coal beds, and to investigate enhanced coal bed methane (ECBM) recovery factors and production rates as a result of CO_2 injection.

Ownership and liability

Gulf Canada leased the property and assumed the liability.

Regulatory and approval conditions

Gulf Canada successfully applied to the ERCB for experimental status of the project.

Pre-injection geological database and site characterisation

This project focused on testing the CO_2 injectivity and methane production of the Manville Group coals. Several sites were evaluated. Evaluation wells were drilled in the deep Mannville (1,300 m), the shallow Ardley (400 to 600 m) and the Horseshoe Canyon (300 m) coal intervals. Core samples were collected and degassed under controlled conditions to estimate gas content. The wells were logged and sorption isotherms were measured on crushed core for CH_4, CO_2 and N_2. In-situ flow-pressure tests were used to estimate permeability. Thick sections of coals were encountered, exceeding three metres in all of the wells. In general, the shallower coals have higher permeability but lower gas contents compared to the deeper Mannville coal. Permeability ranged 100-fold from 0.1 to 10 md. For CO_2 storage, the shallower coal reservoirs are appealing because of the lower drilling costs and the lower compression required to inject CO_2. However, the first ECBM field tests were done in the deeper Mannville coals due to the availability of an existing CBM well.

Source of CO_2

The food grade CO_2 was purchased from a commercial source in Medicine Hat. For the 13% CO_2 flue gas injection, the exhaust gas from a natural gas/propane fuelled compressor used for underbalanced drilling was captured and compressed and injected on site.

Transport of CO_2

The CO_2 and N_2 were transported by truck from the supplier directly to the injection site except for the 13% CO_2 flue gas. The flue gas was produced by an underbalanced drilling compressor at the sight.

Additional project details

There were two wells tested at this site with gas injections. The injections utilised a 'huff and puff' scheme (injection, a soak and a production period) with two micro-pilot tests performed in each well. The first well was tested with pure CO_2 and, a year later, with flue gas (13% CO_2, 87% N_2). The second well was tested with pure N_2 and, a month later, with synthetic flue gas (47% CO_2 and 53% N_2).

The well was initially produced on primary followed by a build-up test to estimate permeability (4 md). Before the longer pure CO_2 injection test, a CO_2 injectivity/fall-off test using a 12 tonne slug of liquid CO_2 to ensure injectivity under existing fracturing pressure was completed. A short production period followed. As this test was successful, it allowed the testing program to continue for a prolonged injection of twelve 15 tonne slugs of CO_2.

For each micro-pilot, injectivity was maintained at adequate rates in the low-permeability Mannville reservoir. Soak periods ranged from 30 to 60 days. Then the wells were returned to production for 30 days to determine each well's productivity and produced-gas composition. This huff and puff test was followed by a final shut-in test to obtain pressure and permeability measurements after injection. These data sets built during the tests were used to calibrate reservoir simulators to estimate the CO_2 storage potential and the enhanced hydrocarbon gas recovery in the design of the multi-well pilot.

Stakeholder engagement

No formal stakeholder engagement was conducted, other than the meetings and reports provided to those funding the project. Presentations were made at professional meetings.

Risk assessment process

Risk assessment was addressed in the applications and reporting to the Energy Resources and Conservation Board, the regulatory agency for the province; as well as standard safety practices developed by the oil and gas industry in Alberta.

Significant learnings from the project

- The five simulation software packages tested were incapable of predicting the produced gas composition in the field test with any degree of accuracy. Better understanding of the process mechanisms involved, for example, multiple gas sorption and diffusion, and changes in coal matrix volume due to sorption/desorption of gases, is needed to guide any future development of the models.
- Even in tight reservoirs, continuous CO_2 injection is possible - injectivity declines but can still inject. The CO2 injectivity was greater through the use of alternating injection shut-in sequences and perhaps as a result of coal weakening. It was thought that any injection into a coal seam with 1 md permeability would be difficult. It was found that injection increased the absolute permeability and effective permeability to gas to a level that allowed easy injection.
- Two patents were granted based on the project: (i) Process for recovering methane and/or sequestering fluids –US 6,412,559 B1 (2002) and (ii) US 6,860,147 B2 Process for predicting porosity and permeability of a coal bed (2005)

PROJECT SUMMARY

Project name:
Frio Texas

Project organisation:
Bureau of Economic Geology (U. Texas)

Project type:
Deep saline aquifer

Project scale
Small scale (1,600 t)

Type and depth of reservoir:
Sandstone, 1500 meters

Total cost of project:
USD $4,140,000

Location:
Houston, Texas, USA

Year of first injection:
2004

Current status:
Injection complete

Type of Seal:
Thick shales and small fault block

PROJECT DETAILS

	Project operator	BEG	**Project contact phone**	512-471-4863
	Project contact	Susan Hovorka	**Project contact email**	susan.hovorka@beg.utexas.edu
	Project location	Trinity River Valley, TX, USA	**CO_2 source**	Purchased (Praxair)
	Injection site coordinates	29°49'53"N, 95°18'32"W	**CO_2 transport/delivery**	Truck
	Project planning start	2002	**Injection rate**	160 tonnes/day
	Duration of injection	10 days (4 days second test 2006)	**Injection pressure**	800 psi at wellhead
	Planned injection volume	1600 metric tons	**Total volume injected**	1600 tonnes in two injections
	Reservoir porosity	32-35%	**Reservoir permeability**	2.5 Darcys
MONITORING	**Seismic monitoring**	Radial VSP, Crosswell	**Gravity studies**	Not performed
	Water monitoring	4 wells (29 meters)	**Pressure logging**	Wellhead and downhole
	Soil monitoring	15 soil gas wells (1.2meters)	**Thermal logging**	Wellhead and downhole, wireline
	Atmospheric monitoring	PFT atmospheric tracer detected from venting	**Wireline logging**	Open hole quad combo, Cased hole pulsed neutron, sonic
	Ecological monitoring	PFT via CAT and Seeper trace 2 times	**Observation well**	1 dedicated well
	Tracer analysis	PFT,SF6, Deuterated methane noble gas	**Geochemical research/Fluid sampling**	Downhole sampling from access tubes
	Electromagnetic	EM	**InSAR**	Not performed
RESERVOIR STUDIES	**Reservoir modelling**	TOUGH2, CMG GEM	**Geologic model**	Yes, multiple tools
	Coring	new well, seal to reservoirs	**Seismic**	3D
	Other technologies	U-tube, CASSM designed by LBNL for this project		

Project context

This pilot scale project by the Bureau of Economic Geology (BEG) was designed to serve as a first US geological store of CO_2 in an onshore geological formation. The target interval chosen was Frio sandstone at around 1500m within the South Liberty Oil field, Dayton Texas. The field which produces from a deeper horizon than the Frio is operated by several operators. Texas American Resources LLC was the host and the Bureau of Economic Geology (BEG) is the leading institution on the project and is collaborating with many national laboratories and private institutes. BEG reviewed many saline formations in the US to identify candidates for CO_2 storage. The Frio Formation was selected as a target that could serve a large part of the Gulf Coast.

Aims of the project

The objectives of the Frio Brine project are to (1) demonstrate that CO_2 can be injected into a brine formation safely; (2) measure subsurface distribution of injected CO_2; (3) test the validity of conceptual, hydrologic, and geochemical models, and (4) develop experience necessary for larger scale CO_2 injection experiments.

Ownership and liability

The project was funded by U.S Department of Energy (DoE) National Energy Technology Lab (NETL).

The pilot project was conducted at the South Liberty oil field and operated by Sandia Technologies LLC on behalf of the University of Texas. The surface is privately owned by multiple owners, who leased it to the project. No pipeline was planned or used. Liability was handed commercially by purchase of oilfield insurance by Sandia Technologies on behalf of the University of Texas for operation liability.

Regulatory and approval conditions

The injection well was granted permission to inject by the Texas Commission of Environmental Quality underclass V – experimental section of the US underground injection Control Program. The observation well was permitted for conversion from a producer by plug-back by the Texas Railroad Commission. Each agency granted permission to plug and abandon in 2007.

Pre-injection geological database and site characterisation

The fluvial sandstone of the upper Frio Formation in the Oligocene was targeted for injection at a depth of 1524m ft. An existing well was used for observation. A new injection well was drilled 30m away and 9m downdip from the observation well. Conventional cores were cut and analysis indicated 32 to 35 percent porosity and 2,500 md permeability. The detailed core description was valuable as it resulted in project design improvements. A bed bisecting the interval originally thought to be a significant barrier to flow is a sandy siltstone having a permeability of about 100 md. As a result, the upper part of the sandstone was perforated. Reservoir measurements from the core, the selection of the actual injection zone, provided revised input for the simulation model, which was then rerun to estimate timing of CO_2 breakthrough and saturation changes.

Site-characterisation techniques included:

- review of the regional geological setting
- development of a detailed local geological model
- analysis of wireline logs
- laboratory analysis of core samples
- collection and chemical analysis of brine samples
- pressure-transient analysis of an interference well test
- breakthrough curve analysis for a two-well recirculation tracer test
- CO_2 injection itself served as a two-well tracer test and an interference well test
- Geophysical monitoring of CO_2 movement in the subsurface during and after the injection

Source of CO_2

The food grade CO_2 was purchased from Praxair, a commercial source.

Transport of CO_2

The CO_2 was transported by truck from the supplier directly to the injection site.

Additional project details

The project injected 1600 tonnes of CO_2 into a steeply dipping brine-saturated sand layer at a depth of 1,500 meters, over 10 days. High permeability, steep local dip, and limited lateral flow were considered desirable formation characteristics that would allow rapid equilibration within the experiment.

There were two tests, one in 2004 and a second test in 2006 injected a smaller amount for a shorter period to test the interaction of injection with buoyancy.

The site within an oil-field setting benefited the project as a means of meeting needs for a well-characterised site, as well as budgetary and public-acceptance considerations.

At the selected site, Frio Sandstone comprise multiple sandbodies separated by mudstone confining zones. The 2004 injection was into the "Frio: C" Sandstone, the 2006 injection was into the Frio "blue" Sandstone. A new injection well was drilled for the project and an existing production well was modified to serve as an observation well.

Stakeholder engagement

Gaining public acceptance of CCS was an important objective of the Frio Brine project (Hovorka, 2009). The project employed public outreach methods which included site visits by researchers, local citizens, and environmental groups, media interviews and an online log. During consultation, the public and environmental concerns expressed were considered moderate, practical, and proportional to the minimal risks taken by the project. These generally related to issues such as traffic and potential risks to water resources (*Hovorka, 2009*).

Risk assessment process

The Frio project selected risk avoidance as the major risk approach. For example, the volume to be injected was made smaller through the planning process, by moving the planned wells closer together. Injection was stopped as soon as project objectives had been attained, as a risk and cost avoidance procedure. A large panel of experts and consultants reviewed the project plans and advised methods to avoid risk. Operational risks were recognised and managed through industry heath, safety, and environmental (HS&E) procedures. The project commissioned a formal HS&E manual. Because of the well-characterised nature of the site, the short duration and small injection volumes, long term risk was evaluated as insignificant.

Significant learnings from the project

The following recommendations were reported by the project operators:

- After traditional site characterisation activities to assess site suitability are conducted (e.g., geologic, geophysical, and hydraulic testing), it is recommended that reservoir models be reassessed and updated using data collected during initial CO_2 injection. The initial injection of CO2 can either be considered part of the site-characterisation process, or may be the initial phase of commercial utilisation of the storage reservoir.

As a result of complexities associated with multi-phase, multi-component flow, it is recommended that a reservoir model be developed to simulate the principle storage processes in conjunction with site characterisation, to facilitate integrating disparate field observations and synthesising understanding of subsurface processes.

PROJECT SUMMARY

Project name:
JCOP Yūbari/Ishikari ECBM Project

Project organisation:
The General Environmental Technos Co. Ltd.

Project type:
Enhanced Coalbed Methane

Project scale:
Small scale (884 t)

Type and depth of reservoir:
Coal, 890 meters

Total cost of project:
USD $27,680,000 (YEN 2,685,000,000)

Location:
Hokkaido, Japan

Year of first injection:
2004

Current status:
Injection complete

Type of Seal:
Mudstones

PROJECT DETAILS

	Project operator	The General Environmental Technos Co. Ltd.	**Project contact phone**	06-6263-7310
	Project contact	Hironobu Komaki	**Project contact email**	komaki_hironobu@kanso.co.jp
	Project location	Hokkaido, Japan	**CO_2 source**	Food grade
	Injection site coordinates	43°03'34"N, 141°59'01"E	**CO_2 transport/delivery**	Truck
	Project planning start	2002	**Injection rate**	2-4 tonnes/day
	Duration of injection	2004-2007	**Injection pressure**	< BHP 15.6MPa
	Planned injection volume	10 tonnes/day	**Total volume injected**	Gross 884 tonnes
	Reservoir porosity	1.5%	**Reservoir permeability**	1.1 md
MONITORING	**Seismic monitoring**	Not performed	**Gravity studies**	Not performed
	Water monitoring	Underground water	**Pressure logging**	Wellhead and downhole
	Soil monitoring	Soil Gas and Ground Tilt	**Thermal logging**	Wellhead and downhole
	Atmospheric monitoring	Site-based air monitor	**Wireline logging**	SP, GR, neutron, electrical, density, caliper
	Ecological monitoring	Not performed	**Observation well**	One dedicated well
	Tracer analysis	Not performed	**Geochemical research/Fluid sampling**	Produced gas/water analysis. Layer fluid sampling
	Electromagnetic	Not performed	**InSAR**	Not performed
RESERVOIR STUDIES	**Reservoir modelling**	GEM	**Geologic model**	Yes
	Coring	From 2 wells	**Seismic**	Not performed
	Other technologies	Not known		

Project context

The Japan CO_2 Geosequestration in Coal Seams Project (JCOP) was the Japan's first CO2-ECBM field trial. It took place at Yubari City in the Ishikari Coal Basin of Hokkaido and was completed as a project in March 2008. The principle target of the test was a 5-6m thick coal seam of Eocene-Oligocene age lying at a depth of 900m. The project involved a micro pilot and two multi well injection tests involving an injection and production well which were carried out between May 2004 and November 2007.

Aims of the project

The project aims to evaluate technical and economical feasibility of extracting methane gas while storing CO_2 in Japanese coal seams.

Ownership and liability

The project was funded by the Japanese Government, with full subsidy from the Ministry of Economy, Trade and Industry (METI). The project was led by General Environmental Technos Co, in partnership with the Research Institute of Innovative Technology for the Earth (RITE) and the Japan Coal Energy Centre (JCOAL).

Regulatory and approval conditions

The project was permitted based on the existing Mine Safety Act and High Pressure Gas Safety Act.

Pre-injection geological database and site characterisation

The Ishikari Coal Basin is located in the middle of Hokkaido, covers approximately 800 km2, and is the largest coal basin in Japan. The target coal zone was characterised by proximate and ultimate analyses implemented for core samples used to measure the gas content. The coal rank was high volatile bituminous based on the moisture, ash-free calorific value and vitrinite reflectance data. Adsorption isotherms were measured to derive Langmuir pressure and temperature values for storage capacity calculations.

In the Yubari area, all of the Cretaceous system and overlying Eocene/Oligocene Ishikari series have been deformed by thrusting from the east producing numerous overthrusts, inverted folds, and recumbent folds along a north–south axis *(Fujioka, Yamaguchi, Nako, 2010)*. Nearly all of the Ishikari series in the area is covered with the homogeneous Horonai Shale, which is important for its sealant properties.

Source of CO_2

The food grade CO_2 used was purchased from a commercial source.

Transport of CO_2

The CO_2 was transported by truck from the supplier directly to the injection site.

Additional project details

The primary coal seam of interest was a 5–6 m thick Yubari coal seam located at the depth of 900 m. A micro-pilot test with a single well as well as multi-well CO_2 injection tests with injection and production wells, were carried out in the period between May 2004 and October 2007.

The project included many kinds of ECBM tests such as injection fall-off, CO_2 huff-puff, a series of CO_2 injection, step rate, N2 flooding, and pilot production of enhanced methane *(Fujioka, Yamaguchi, Nako, 2010).*

Stakeholder engagement

Not known.

Risk assessment process

Not known.

Significant learnings from the project

- Gas production rate was obviously enhanced by CO_2 injection.
- Water production rate was not clearly affected by CO_2 injection. Several injection tests suggested that injectivity of CO_2 into the virgin coal seam saturated with water was eventually increased as the water saturation near the injector was decreased by the injected CO_2. As a result it was thought that water saturation played an important role in the determination of CO_2 injectivity as well as gas productivity (Fujioka, Yamaguchi, Nako, 2010).
- CO_2 injection rate was 10 times lower than expected. It is thought the low injectivity of CO_2 was caused by the reduction in permeability induced by coal swelling.
- N2 flooding test was performed in 2006 to evaluate the effectiveness of N2 injection on improving well injectivity. The N2 flooding test showed that daily CO_2 injection rate immediately after N2 flooding was boosted, but only temporarily. The permeability did not return to the initial value after CO_2 and N2 were repeatedly injected. It was also indicated that the coal matrix swelling might create a high stress zone near to the injection well.(Fujioka et al, 2010)
- N2 injection rates became significantly higher than CO_2 injection rate due to higher permeability. CH_4 production was drastically increased by N_2 injection and breakthrough of N_2 was discovered at the production well within 10day injection of N_2. The project showed that the permeability was increased and decreased by N_2 and CO_2 injection respectively.
- Skin Factor might not affect the enhanced CBM production.
- Cleat Opening pressure might be increased by matrix swelling.
- Injection rate could be increased by higher injection pressure.
- It is strongly recognised through the pilot test that reduction of permeability is the main technical issue that should be solved in order to put economical and large scale CO_2-ECBM into practice worldwide.

PROJECT SUMMARY

Project name:
CO_2 Injection at K12-B

Project organisation:
GDF Suez / TNO

Project type:
Deep Oil and Gas –Enhanced Gas Recovery

Project scale
Small scale (80,000 t)

Type and depth of reservoir:
Sandstone, 3,800 meters

Total cost of project:
Not known

Location:
150km NW Amsterdam, Offshore Netherlands

Year of first injection:
2004

Current status:
Injection ongoing

Type of Seal:
Mainly rock salt of the Zechstein

PROJECT DETAILS

	Project operator	TNO	**Project contact phone**	Not known
	Project contact	Robert Arts	**Project contact email**	info@k12-b.nl
	Project location	150km NW Amsterdam, Offshore Netherlands	**CO_2 source**	Gas Processing
	Injection site coordinates	53°20'50"N, 03°05'35"E	**CO_2 transport/delivery**	Onsite
	Project planning start	2002	**Injection rate**	45 tonnes/day
	Duration of injection	3 years	**Injection pressure**	Not known
	Planned injection volume	15,000 tons/year	**Total volume injected**	70,000 tonnes
	Reservoir porosity	10 - 15%	**Reservoir permeability**	20mD
MONITORING	**Seismic monitoring**	No, only baseline	**Gravity studies**	Not performed
	Water monitoring	Not performed	**Pressure logging**	Wellhead and downhole
	Soil monitoring	Offshore	**Thermal logging**	Wellhead and downhole
	Atmospheric monitoring	Not performed	**Wireline logging**	Caliper, CBL, Downhole video, EMIT, Gamma ray
	Ecological monitoring	Not performed	**Observation well**	Via production wells
	Tracer analysis	PMCP, PDMCH	**Geochemical research/Fluid sampling**	Produced fluid analysis
	Electromagnetic	Not performed	**InSAR**	Offshore
RESERVOIR STUDIES	**Reservoir modelling**	SIMED II, Eclipse 300, TOUGH2	**Geologic model**	Petrel
	Coring	Yes	**Seismic**	Yes, 3D, only older baseline prior to injection
	Other technologies	Production history		

Project context

The K12B reservoir project is an offshore reinjection of CO_2, which is itself part of a Dutch study launched in 2002 known as CRUST (CO_2 Re-use through Underground Storage), started reinjecting CO_2 in April 2004 into the K12B offshore natural gas field in the North Sea. The first test in 2004 was in a separate compartment of the reservoir, away from where CO_2 was injected from 2005 onwards. After CRUST the CO2 injection and storage has been part of various research projects such as CATO and CATO2 most recently. The K12B field operated by GDF Suez, originally contained natural gas with a CO_2 content of around 13 %. It has been in production since 1987 and is now almost depleted. The project claims to be the first in the world where CO_2 is reinjected into the same reservoir from which it was produced.

Aims of the project

The project aims to investigate the feasibility of CO_2 injection and storage in depleted natural gas fields and the corresponding monitoring and verification.

Ownership and liability

Activities at K12-B are currently operated by Gaz de France, GDF Suez, a partner of the CASTOR integrated project. TNO is heavily involved in monitoring and modelling of the CO2 injection.

Regulatory and approval conditions

The Netherlands Kyoto target: in 2020, the CO_2-emissions should have been reduced to the 1990 level, i.e. 162 Mt per year has clear objectives. Various measures have been investigated to reach that target starting with policy reform. In 2002, the Dutch Minister of Economic Affairs introduced a new policy to promote feasibility studies into CO_2 storage in the subsurface (The CRUST program) with a number of demonstration projects, which were supported by the Dutch government following this.

Pre-injection geological database and site characterisation

The target formation for reinjection was the Upper Slochteren member of the Rotliegendes Sandstone located at a depth of about 3800 meters. Site characterisation included building a geological model of the reservoir and overburden, coring activities to understand stratigraphy and full facies analysis and realisation modelling. All faults within the target reservoir were normal faults with modest throws (10-100m) with none of them reaching the top of the seal and in addition most faults were found to be completely cemented. The overlying Zechstein Formation contains up to 4 evaporite cycles indicated by mineral concentrations. The seals are dolomite, anhydrite, halite and shale.

Well integrity studies were conducted during both test components of the project which had two injection wells, one for each test conducted.

Source of CO_2

The CO_2 was produced as a by-production of the natural gas from the K-12B offshore field. The gas extracted from the well contained 13% CO_2, which was stripped from the gas, compressed and re-injected. The purified natural gas was transported on shore by pipeline for injection into the grid.

Transport of CO_2

An injection pipeline transports the CO_2 to the injection well from the processing platform to the injection.

Additional project details

The 2 tests involved in the K12-B project were at different locations in the reservoir. Test 1 (May – December 2004, 11,000 t CO_2) is a CO_2 injection into a single-well depleted reservoir compartment. Test 1 showed that CO_2 injectivity is quite good despite the low permeability of the reservoir. The reservoir response and the behaviour of injected CO_2 are within the expected range.

Results of test 1 were used to optimise the measurement program of test 2 (March 2005) with CO_2 injection into a nearly depleted reservoir compartment (two producing gas wells, and a CO_2 injection well). Objectives of test 2 were to test the predictability and enhanced gas recovery potential with simulation and tracers injections. This test is still successfully ongoing.

Stakeholder engagement

CO_2 Injection at K12-B made it into the news via television and news papers, the minister of economic affairs visited the platform, various reports and articles were written and several presentations where held at important scientific conferences.

Risk assessment process

Risk assessment was done before and extended during CO_2 injection.

Significant learnings from the project

- CO_2 injection has not brought any unforeseeable problems.
- Well integrity indicates proper performance.
- No indication for leakage.
- Chemical tracers supplied valuable data regarding migration of CO_2 in the reservoir.
- Pressure development and tracer breakthrough as expected.

PROJECT SUMMARY

Project name:
KETZIN

Total cost of project:
Approx 42 Million Euros (approx. 56 million $US)

Project organisation:
GFZ German Research Centre for Geosciences

Location:
Ketzin/Havel near Berlin, Germany

Project type:
Deep Saline Aquifer

Year of first injection:
2008

Project scale
Small scale (<70,000 t)

Current status:
Injection stops August 2013

Type and depth of reservoir:
Sandstone, 630 - 650 meters

Type of seal:
>165 m of thick shaly cap rocks, Claystones and Anhydrite

PROJECT DETAILS

	Project operator	VNG Gasspeicher GmbH	**Project contact phone**	0049 331 288 1553
	Project contact	Axel Liebscher	**Project contact email**	alieb@gfz-potsdam.de
	Project location	Berlin, Germany	**CO_2 source**	Food Grade (Linde AG)
	Injection site coordinates	51°12'13"N, 12°21'34"E	**CO_2 transport/delivery**	Truck
	Project planning start	2004	**Injection rate**	up to 70 tonnes/day
	Duration of injection	5 years	**Injection pressure**	~59 - 63 bara at injection wellhead, 72 to 79 bara at bottom hole during active injection
	Planned injection volume	Maximum of 70,000 t	**Total volume injected**	65,000 tonnes
	Reservoir porosity	13 – 26 vol%	**Reservoir permeability**	40-80 mD
MONITORING	**Seismic monitoring**	2D, 4D, VSP, MSP, Crosswell, Passive	**Gravity studies**	Not Performed
MONITORING	**Water monitoring**	Not known	**Pressure logging**	Wellhead and downhole
MONITORING	**Soil monitoring**	20 automated sampling locations	**Thermal logging**	Wellhead and downhole
MONITORING	**Atmospheric monitoring**	Not known	**Wireline logging**	Cased Hole logging
MONITORING	**Ecological monitoring**	Microbial techniques	**Observation well**	3 dedicated wells
MONITORING	**Tracer analysis**	Krypton, SF6	**Geochemical research/Fluid sampling**	Composition and isotope analysis of produced gas from observation wells
MONITORING	**Electromagnetic**	ERT, CSEM	**InSAR**	Not performed
RESERVOIR STUDIES	**Reservoir modelling**	ECLIPSE 100, ECLIPSE 300, TOUGH2	**Geologic model**	Petrel
RESERVOIR STUDIES	**Coring**	Pre-injection coring, coring of CO2 treated reservoir in 2012	**Seismic**	3D reflection seismic
RESERVOIR STUDIES	**Other technologies**	Not known		

Project context

The Ketzin project began within the framework of the EU project CO2SINK in 2004; it is Germany's first CO_2 storage site and fully in use since the injection began in June 2008. The project involves the injection of CO_2 into a Triassic reservoir within a domal structure below the village of Ketzin/Havel. Overlying reservoirs within the Jurassic system had been used for natural gas storage between the 1960's and 2004.

Aims of the project

The aim of this project is to increase the understanding of geological storage of CO_2 in saline aquifers and develop the basis for geological storage techniques by injecting CO_2 into a saline aquifer near the town of Ketzin/Havel, Germany.

Ownership and liability

The site is owned and operated by VNG Gasspeicher GmbH under the entrepreneurship of GFZ..

Regulatory and approval conditions

In Germany, as a research and development project, the maximum amount of stored CO_2 is limited by legal regulations to 100,000 tonnes. The project has been permitted under the German mining law (BBergG). The EU Directive does not apply to the Ketzin pilot site

Pre-injection geological database and site characterisation

The project characterisation considered the geohistory, lithology and facies, hydrogeology, microbiology and geochemisty in great detail. The Ketzin site is located in the eastern part of a double anticline named Roskow-Ketzin anticline. The immediate overburden above the salt pillow is constituted by geologic formations of the Triassic (Buntsandstein, Muschelkalk, and Keuper) and the Lower Jurassic. The Weser and Arnstadt formations form an approximately 165 m thick caprock section above the Stuttgart Formation consisting of mainly claystone, silty claystone, and anhydrite. The lower storage target of the Stuttgart Formation is on average 80 m thick and lithologically heterogeneous: sandy channel-(string)-facies rocks with good reservoir properties that alternate with muddy, flood-plain facies rocks of poor reservoir quality. The target sandstone interval weaved between mudstones, is 10 to 20 meters thick where subchannels are stacked Detailed baseline seismic investigations were performed to ensure that the dimensions, geometry and properties of the reservoir, and especially of the reservoir seal, were well understood before injection.

Source of CO_2

The CO_2 used for the injection is predominantly food grade purchased from a commercial source. In summer 2011 ~ 1.5 kt CO2 captured from the oxyfuel pilot plant Schwarze Pumpe were injected.

Transport of CO_2

The CO_2 was transported by truck from the supplier directly to the injection site.

Additional project details

The site was selected based on favourable geological structures for storage, existing infrastructure, local political community support for the project and involvement of permitting authorities in the project definition stages. As well, the site location being close to metropolitan populations provided a unique opportunity to demonstrate onshore CO_2 storage.

The project has been managed through seven sub-projects, each of which are interlocking and making an important contribution to the overall project.

Stakeholder engagement

A key premise of all communication activities for the project was to ensure an open and transparent dialog with the general public, especially the local community. Types of engagement employed included:

- The visitor centre on site, considered the most important contact point and a corner stone for close collaboration with stakeholders and the dissemination of knowledge. The centre hosts permanent exhibits (e.g. posters, core samples, physical models) that can be used to visually illustrate the concept of CO_2 storage.
- Interested groups, especially from the local community, were invited by GFZ to attend an open day on site in May 2011. The event was well received and carried out in close cooperation with people from the nearby city of Ketzin/Havel, for example, with the involvement of the Mayor, the local fire brigade and other service providers.
- Project status and progress are also covered in videos and brochures, with attention drawn to the project website (www.co2ketzin.de) where more general and scientific information is also available.

Risk assessment process

Detailed risk assessment considered groundwater, human health and safety, environment, atmospheric impacts, well bore integrity, oil and gas storage, cap rock and secondary cap rock integrity, faults and reservoir behaviour. The process considered top-level risks of the project to include all aspects of safety, cost, schedule and system performance. During operation, the project has utilised an FEP (features, events and processes) database which includes all risk sources for a generic CO_2 storage project adapted to this particular project as part of the project overall work process.

Significant learnings from the project

- The geological storage of CO_2 at the pilot site runs smoothly and safely.
- Interactions between fluid and rocks induced by the injected CO_2 have no impact on the integrity of the cap rocks and reservoir, and no real consequences at the Ketzin pilot site.
- Geochemical and biological testing and monitoring helped to improve the injectivity by better understanding the processes within the reservoir.
- A wide range of different technological solutions tested for monitoring at the Ketzin site will provide a solid foundation for larger scale projects in future.

PROJECT SUMMARY

Project name: Lacq-Rousse project	**Total cost of project:** USD $79,080,000 (60M Euro) (April 17, 2013) (whole chain)
Project organisation: Total	**Location:** Rousse Field, Aquitaine Basin, SW France
Project type: Depleted gas; fractured reservoir	**Year of first injection:** 2010
Project scale: Small scale (50,000 tonnes)	**Current status:** Completed injection
Type and depth of reservoir: Mano Dolomite at 4,500-4,600 m	**Type of seal** Clay marl (Flysh)

PROJECT DETAILS

	Project operator	Total	**Project contact phone**	+33 1 47 44 72 94
	Project contact	Jacques Monne	**Project contact email**	jacques.monne@total.com
	Project location	Rousse Field, Pau, France	**CO_2 source**	Oxy boiler
	Injection site coordinates	43°24'27''N, 0°38'08''E	**CO_2 transport/delivery**	30 km pipeline
	Project planning start	Construction 2006	**Injection rate**	100 tpd.
	Duration of injection	Jan 2010 to March 2013	**Injection pressure**	80 bar (Final pressure)
	Planned injection volume	75 kt/year	**Total volume injected**	50,000 tonnes
	Reservoir porosity	Avg 3%	**Reservoir permeability**	<1 millidarcy
MONITORING	**Seismic monitoring**	Passive	**Gravity studies**	Not performed
	Water monitoring	Yes; surface, shallow and deep	**Pressure logging**	Wellhead and downhole
	Soil monitoring	Performed	**Thermal logging**	Wellhead and downhole
	Atmospheric monitoring	LIDAR	**Wireline logging**	Initial; not time-lapse
	Ecological monitoring	Environmental monitoring	**Observation well**	No observation well
	Tracer analysis	Co-inject 4% Ar with CO_2	**Geochemical research/Fluid sampling**	CO_2 stream composition
	Electromagnetic	Not performed	**InSAR**	Not performed
RESERVOIR STUDIES	**Reservoir modelling**	ECLIPSE 300, Geomechanical, pressure modelling	**Geologic model**	Performed
	Coring	Performed	**Seismic**	Fibre optics for microseismic monitoring
	Other technologies	Not known		

Project context

The project is the first French industrial scale operation that will test during two years and demonstrate an entire CO_2 capture and storage process, from the CO_2 emissions source (an oxyboiler) to an underground storage in an onshore depleted gas field. The project involves capture of CO_2 taking place in the industrial complex of Lacq, a town located in the South West of France in the Pyrénées-Atlantiques department in the Aquitaine Region and transporting this by pipeline to a depleted reservoir at the Rousse gas field located at Jurançon, 30 km away from Lacq and 5 km South of the city of Pau.

Aims of the project

Total's aims for the storage phase of this project were to develop monitoring tools, techniques and methodology to assess the viability of long term geological CO_2 storage with an emphasis on the safety of people and property in the vicinity. The project has three key objectives:

1) Demonstrate the technical feasibility and reliability of an integrated CO_2 capture, transportation, injection and storage onshore scheme for steam production at an industrial scale.
2) To develop and operate at a 30MW scale an oxycombustion boiler for CO_2 capture, particularly with a view to applications in the production of extra-heavy oils.
3) Develop and apply geological storage qualification methodologies, monitoring and verification techniques on a real operational case to prepare future larger scale long term storage projects

Ownership and liability

The project is owned and operated by Total Exploration and Production France.
No liability information was found for this project.

Regulatory and approval conditions

No E.U. directive when the project was started. Obtained French authority to inject. The project was approved with official authorisation for the injection to occur over two years followed by three years of observation and monitoring. Other conditions prescribed by the Official Authorisation included following the Rousse storage management plan with groundwater, surface water, atmospheric and biological monitoring conducted for baseline, during injection and for 3 years post injections.

Pre-injection geological database and site characterisation

The initial site characterisation studies needed specific data not just of the reservoir (petrophysics, mineralogy, fluids, facies and heterogeneities) extended to the cap rock units, to the entire overburden, to the natural resources to be protected (Tertiary saline and potable aquifers in the case of Rousse) and to the injection well and monitoring wells. Specific modelling was not restricted to the reservoir: one of the results of the Rousse characterisation phase is a 100 km^2 earth model of the entire storage complex from the reservoir bottom to the surface including the surrounding wells. It is centred on the Rousse structure and includes the aquifers. It will allow evaluating the maximum capacity of the storage, performing integrity studies and risk analysis studies.

Source of CO_2

The CO_2 is sourced from flue gas from the Lacq pilot plant, Oxy-combustion boiler.

Transport of CO_2

The CO_2 is transported from Lacq to the injection site at Rousse through 27 km of pipeline.

Additional project details

The Mano reservoir is a fractured dolomitic reservoir lying at around 4,500m below ground level (-4200 m below MSL). It is 120 m thick, 70 m of which have been cored. The Cretaceous cap rock, which is part of a 2,000 meter section of clay marl (flysch) has been also partly cored. The Initial reservoir pressure was 48.5 MPa at 4,500m.

150 degrees C; 3% porosity, matrix perm <1 mD, but is a fractured reservoir.

Stakeholder engagement

There was opposition by a few community members, followed by a legal process and public enquiry, then approval. 'Transparency" in communication with the stakeholders has been one of the key factors in public acceptance. It remains a permanent "concern" in the project to be taken into account during the whole life of a CCS experiment and for the future industrial deployment of CCS. The project has conducted its public dialogue through a transparency policy and the following activities:

- Identification of key stakeholders (ONG, mayors…)
- Early public meetings in 2007 (4 public meetings)
- Follow up information committee (7 meetings)
- Information letter every quarter (14)
- Phone hotline available

Significant learnings from the project

Not known.

PROJECT SUMMARY

Project name: Marshall County	**Total cost of project:** US$13,230,000
Project organisation: CONSOL Energy Inc.	**Location:** Marshall County, WV, USA
Project type: Enhanced Coalbed Methane	**Year of first injection:** September 2009
Project scale Small scale (2,900 t)	**Current status:** Operational
Type and depth of reservoir: Bituminous HVB Coal, 365 to 549 meters	**Type of seal:** Not known

PROJECT DETAILS

	Project operator	Consol Energy Inc.	**Project contact phone**	(412) 854-6607
	Project contact	James Locke	**Project contact email**	jimlocke@consolenergy.com
	Project location	Marshall County, WV, USA	**CO_2 source**	Regional Ethanol plant by-product
	Injection site coordinates	39°50'00"N, 80°35'21"W	**CO_2 transport/delivery**	Truck
	Project planning start	2002	**Injection rate**	6-10 tonnes/day
	Duration of injection	2009-2011	**Injection pressure**	700-933 psi
	Planned injection volume	20,000 tons (18144 tonnes)	**Total volume injected**	2,900 tonnes through 2012
	Reservoir sorptivity	Not known	**Reservoir permeability**	1-10 mDarcy
MONITORING	**Seismic monitoring**	Not performed	**Gravity studies**	Not performed
	Water monitoring	3 Dedicated shallow wells (100ft)	**Pressure logging**	Wellhead and downhole
	Soil monitoring	CO2 soil flux monitoring	**Thermal logging**	Wellhead and downhole
	Atmospheric monitoring	Not performed	**Wireline logging**	Not known
	Ecological monitoring	Not mentioned	**Observation well**	15 AOR wells for baseline + 2 dedicated observation wells
	Tracer analysis	PFC, dC13	**Geochemical research/Fluid sampling**	Not known
	Electromagnetic	Not performed	**InSAR**	Not known
RESERVOIR STUDIES	**Reservoir modelling**	Not known	**Geologic model**	Not known
	Coring	Not known	**Seismic**	3D seismic was taken
	Other technologies	Surface tiltmeter array		

Project context

This project, located in Marshall County, West Virginia, in the Northern Appalachian Basin was the first of a kind field trial of enhanced coal bed methane (ECBM) with the simultaneous storage of CO_2 in an unmineable coal seam.

The project was funded under the U. S. Dept. of Energy Cooperative Agreement No. DE-FC26-01NT41148. CONSOL Energy Inc. has been the operator and operational managers and NETL have been managers of the project.

Aims of the project

The aim of the Marshall county project is to evaluate enhanced coal bed methane recovery and simultaneous carbon dioxide sequestration.

Ownership and liability

The project is owned and operated by *CONSOL Energy Inc.*

Site access is via *CONSOL Energy Inc.*'s right-of-way project area access provided through the landowner lease agreements. CONSOL Energy assumes all liability for this project.

Regulatory and approval conditions

Drilling permits and an environmental assessment with a consultation component were required at the initial planning stage of the project. Approval with a "*finding of no significant impact*" was issued in March of 2003 for the project to proceed. Injection was permitted at an injection pressure of up to 933 psi on the West Virginia Department of Environmental Protection (WVDEP) Class II underground injection control (UIC) permit. However, an application was made to increase the injection pressure to 1,450 psi as a result of an observed reduction in injection rates 2009-2010.

Pre-injection geological database and site characterisation

The project included work to improve on existing subsurface maps and better understanding of structure and fractures in the area. The test site is located in Fish Creek valley, Marshall County, West Virginia, in flat-lying sedimentary rock strata of the Permian age Dunkard Group. The stratigraphy of the area consists of alternating layers of clastic sedimentary rocks (sandstone, siltstone, shale, mudstone, and claystone), limestone, and coal beds. At this site, the Upper Freeport coal is located at depths of 365 to 549 meters. Its depth along with abrupt thickness change and irregular distribution make the Upper Freeport unmineable in the area.

Depth conversion, Cleat and fracture modelling as well as other reservoir simulation models were developed as part of the project's efforts to build base models. Environmental parameters were monitored for baseline information, repeated during injection, and are planned for the post injection phase.

This was followed by historical matching through sensitivity analysis, production and injection history matching, which were all carried out prior to CO_2 injection.

Wells are arranged to stimulate methane across a 200-acre area of involving two coal seams. Six wells at three well sites were drilled with both horizontal and vertical components to ensure extensive contact with the coal seams. The central wells of a modified five spot pattern were initially used for methane production were later converted into CO_2 injection. CO_2 injection into the Upper Freeport coal seam began in September 2009.

Source of CO_2

The CO_2 was purchased from a commercial source in liquid state.

Transport of CO_2

The Liquid CO_2 is delivered to the site by truck and transferred into a holding tank on site.

Additional project details

Once the CO_2 arrived on site, it is split into two streams and transferred to the two centre injection wells, one flowing to the north and the other flowing to the south. Each injection line was equipped with a flow meter, pressure transducer and a pneumatic control valve allowing for accurate measurement and control of the injection.

Stakeholder engagement

The project has conducted a range of activities designed to educate, engage and inform residents, businesses and community leaders of the nature, risks and mitigation associated with the project. Activities have including:

- Press releases and media communication efforts.
- Conference presentations.
- Locally targeted public information sessions specific to the Appalachia region.
- Digital video clips uploaded to the internet and handouts based on video images.
- Targeted education sessions at local schools and summer schools.

Risk assessment process

Preliminary environmental assessment performed to meet National Environmental Policy Act (NEPA) requirements.

Ongoing sampling of area of review CBM well produced gas and waters, deep-well annulus gas, drinking water zone water and gases, stream water and vadose zone soil gas.

Significant learnings from the project

- Tiltmeter measurements show some surface uplift (positive deformations) along the trajectories of injection wells. A maximum surface uplift of 3.3 mm (0.13 inches) was measured.
- When a fluid is injected into the coal reservoir, surface uplifts may be due to an increase in the reservoir pressure or may be caused by coal swelling during the injection of carbon dioxide.

PROJECT SUMMARY

Project name:
Masdar/ADCO Pilot project

Project organisation:
Masdar Carbon

Project type:
Enhanced Oil Recovery

Project scale
Small scale

Type and depth of reservoir:
Carbonates, 2,895 meters

Total cost of project:
Not known

Location:
Abu Dhabi, United Arab Emirates

Year of first injection:
2009-2010

Current status:
Injection Complete

Type of Seal:
Shales

PROJECT DETAILS

	Project operator	ADCO	**Project contact phone**	Masdar (+971) 2 653 3333
	Project contact	Not known	**Project contact email**	carbon@masdar.ae
	Project location	Abu Dhabi, United Arab Emirates	**CO_2 source**	Commercial
	Injection site coordinates	21°13'13"N, 54°17'50"E	**CO_2 transport/delivery**	Truck
	Project planning start	2007	**Injection rate**	60 tonnes/day
	Duration of injection	2 years	**Injection pressure**	3,300 psi
	Planned injection volume	22,000 tonnes	**Total volume injected**	Not known
	Reservoir porosity	Not known	**Reservoir permeability**	Not known
MONITORING	**Seismic monitoring**	Not known	**Gravity studies**	Not known
	Water monitoring	Not known	**Pressure logging**	Not known
	Soil monitoring	Not known	**Thermal logging**	Not known
	Atmospheric monitoring	Not known	**Wireline logging**	pulsed neutron logging (PNL)
	Ecological monitoring	Not known	**Observation well**	One dedicated well
	Tracer analysis	Not known	**Geochemical research/Fluid sampling**	Not known
	Electromagnetic	Not known	**InSAR**	Not known
RESERVOIR STUDIES	**Reservoir modelling**	CO2-PVT, SCAL	**Geologic model**	Not known
	Coring	Not known	**Seismic**	Not known
	Other technologies	Not known		

Project context

This project was a pilot project which researched the injection of CO_2 into the carbonate oil bearing reservoirs of the Rumaithia field south of Abu Dhabi city.

In 2007, the United Arab Emirates, as part of their climate change initiative, *Madsar Carbon* began developing 'the Abu Dhabi CCS Network'. The project claims to be one of the world's first integrated carbon capture networks with both capture and storage/usage of CO_2. As part of testing the feasibility for this large scale CCS project, *Masdar Carbon* and ADCO initiated this CO_2 enhanced oil recovery (EOR) pilot project, the first of its kind in the Middle East (*Masdar, 2011*).

Aims of the project

The project aims to evaluate the feasibility of EOR using CO_2 demonstrate and gain practical experience implementing CCS in the middle east.

Ownership and liability

The project is owned by the Abu Dhabi Future Energy Company (*Masdar Carbon)* and operated by the Abu Dhabi National Oil Company (*ADCO*).

Regulatory and approval conditions

Not known.

Pre-injection geological database and site characterisation

Not known.

Source of CO_2

The CO_2 used in this pilot was supplied by Praxair Gulf Industrial gases under contract to Abu Dhabi Future Energy Company (*MASDAR*).

Transport of CO_2

CO_2 was delivered to the injection site via truck.

Additional project details

Not known.

Stakeholder engagement

Not known.

Risk assessment process

Not known.

Significant learnings from the project

Not known.

PROJECT SUMMARY

Project name:
MGSC Loudon Field Phase II

Project organisation:
Midwest Geological Sequestration Consortium (MGSC)

Project type:
Enhanced Oil Recovery

Project scale
Small scale (39 t)

Type and depth of reservoir:
Cypress Sandstone, 457 meters

Total cost of project:
MGSC P2 budget of US$ 8.7 million

Location:
Loudon Field in Fayette County, Illinois, USA

Year of first injection:
2007

Current status:
Injection complete

Type of Seal:
Cypress Shale

PROJECT DETAILS

	Project operator	Petco	**Project contact phone**	(217) 244-8389
	Project contact	Rob Finley	**Project contact email**	finley@isgs.uiuc.edu
	Project location	Loudon Field in Fayette County, Illinois, USA	**CO_2 source**	Commercial source
	Injection site coordinates	39°04'08"N, 89°00'60"W	**CO_2 transport/delivery**	Truck
	Project planning start	2006	**Injection rate**	5-10 tonnes/day
	Duration of injection	5 days	**Injection pressure**	300-700 psi
	Planned injection volume	Not known	**Total volume injected**	39 tonnes
	Reservoir porosity	16%	**Reservoir permeability**	31mD
MONITORING	**Seismic monitoring**	Not performed	**Gravity studies**	Wellhead and downhole
MONITORING	**Water monitoring**	3 dedicated shallow wells (6-7m)	**Pressure logging**	Wellhead,downhole and annulus zones
MONITORING	**Soil monitoring**	Soil gas samples were taken	**Thermal logging**	Wellhead, downhole and annulus zones
MONITORING	**Atmospheric monitoring**	Ambient air quality CO2 detector	**Wireline logging**	Cased hole logs (RST, USIT, CBL)
MONITORING	**Ecological monitoring**	Not known	**Observation well**	No dedicated well
MONITORING	**Tracer analysis**	Not performed	**Geochemical research/Fluid sampling**	Brine/gas from 3 production wells
MONITORING	**Electromagnetic**	EM induction	**InSAR**	Not performed
RESERVOIR STUDIES	**Reservoir modelling**	Project created	**Geologic model**	Project created
RESERVOIR STUDIES	**Coring**	Commercial characterisation	**Seismic**	Commercial characterisation
RESERVOIR STUDIES	**Other technologies**	Electrical earth resistivity monitoring, aerial photography, 62 SP+ resistivity logs, 4 GR logs (historical)		

Project context

The MGSC Huff'n'Puff test at Loudon field was the first Phase II EOR project of the MGSC pilot project to evaluate the potential for geological storage of CO_2 in the mature Illinois Basin Oil fields as part of an EOR programme. Huff'n'Puff is an established oilfield EOR technique for tertiary oil extraction by alternating periods of injection followed by production.

The project was carried out by the Midwest Geological Sequestration Consortium (MGSC), part of the US Department of Energy (DoE) Regional Carbon Sequestration Partnerships (RCSP) initiative. The overall DoE program follows a three phase implementation. As a validation scale project, the project forms part of Phase II of the RCSP program evaluating promising CO_2 storage opportunities. MGSC has three phase II storage validation projects examining Enhanced Oil Recovery.

Aims of the project

The aim of this project is to evaluate the potential for geological sequestration of CO_2 in mature Illinois Basin oil reservoirs as part of an EOR program utilising the Huff'n'Puff method.

Ownership and liability

Project ownership: Petco, Inc.

Land ownership – injection site and surrounding, transport-pipeline route approval: Privately owned

Liability: Petco, Inc.

Regulatory and approval conditions

Permitting requirements for CO_2 injection was noted as an issue for securing operators during the establishment of the project. Other issues included approval and coordination with township roads commissioner for CO_2 to be trucked to the injection site and surface access, well workover limits, drilling rigs, budgets and staffing.

Because of the nature of the injection process, this injection test was considered a stimulation and a UIC permit was not required.

Pre-injection geological database and site characterisation

The Loudon field is a very large anticlinal structure that was discovered in 1938 and has produced nearly 400 million barrels of oil. The Mississippian Weiler or Cypress Sandstones were the target reservoirs at 457 meters average depth. The Weiler is a deltaic deposit consisting of fine- to very fine-grained, well-cemented quartzose sandstone having good well-to-well continuity. Cypress sandstone is characterised by very fine- to fine-grained sandstone in 1.8-3 meter packages, interbedded with shales. These sandstone formations are typically elongated bodies that may coalesce to form large flow units. Well information gathered from early geophysical logs (predominantly SP) and core descriptions were used to characterise the Weiler Sandstone. 62 logs and 17 cores were scanned and digitised, 11 cores from the Owens lease facies were utilised in modelling.

Source of CO_2

The CO_2 was purchased from a commercial source.

Transport of CO_2

Liquid CO_2 was transported to site with trucks and loaded into storage tanks held onsite.

Additional project details

The Owens lease within the Loudon Field was selected as the location for the project. The lease originally had 4 wells producing oils in the Cypress sandstone. Presently the Owens lease has 2 producing wells, within the 40 acre lease. Surrounding leases have water injector wells nearby Owens well 1 selected for CO_2 injection. Modelling suggests there is limited geologic communication between Owens well 1 and the other wells of the lease. Modelling was conducted including at least two wells outside the target well location as a means to manage outer boundary effects.

In the summer of 2007, 39 tonnes (43 tons) of CO_2 were injected into an oil production well in the southern part of the Loudon Field over a five day period at a rate of 5-10 tons per day. Following injection the well was shut in for a week to allow the CO_2 to mix with the oil in place, (soak) then the liquid was produced via the rod pump. Prior to injection the well had produced 0.5-1.0 bbl. of oil per day, immediately following injection the well had a maximum daily rate of 8 BOPD which after a week declined over a period to 5-5 BOPD . Incremental production during the first two months following the soak period was 93 bbl.

Monitoring, verification and accounting program consisted of atmospheric monitoring, shallow geophysical surveys, gas sampling, shallow groundwater monitoring, groundwater geochemical modelling, casehole well logging, and reservoir brine monitoring.

Stakeholder engagement

Public outreach was conducted by researchers from Illinois state Geological Survey (ISGS) including:

- Contacting key stakeholders (surrounding landowners, local officials, residents),
- Site visits from community members,
- Groundwater reporting to surrounding landowners,
- Ongoing contact with landowners,
- Field test brochures and general CCS brochures produced and distributed,
- Posters and presentations were kept onsite for visitors.

Risk assessment process

The risk assessment was qualitative and predominantly applied during the site screening and selection process. The general approach was to understand potential risks during CO_2 injection by understanding historical oilfield operations at the sites and the current operators' role in the day to day activities of existing oil fields.

Significant learnings from the project

- It was probably unnecessary to reduce the casing pressure early in the production period following the soak period.
- Because this field was discovered and developed before the advent of modern wireline logging techniques, the use of normalised SP was integral in the geological modelling to develop the sandstone-shale distribution and permeability estimates. The limited availability of core analyses was overcome by using general well log-transform with a subset of porosity data available.
- Saturated soil conditions near the surface were problematic during MVA and may mean the Vadose zone is not feasible in the Illinois Basin.
- The use of geophysical survey techniques in oil fields maybe less applicable due to existing infrastructure, in particular buried pipelines.
- Gas sampling of the casing gas proved important and useful to quantify the CO_2 production and corrosion potentials.
- Groundwater monitoring conducted on surround lands played an important role in alleviating landowner concerns surrounding the project.

PROJECT SUMMARY

Project name:
MGSC Mumford Hills (EOR II) Phase II

Project organisation:
Midwest Geological Sequestration Consortium (MGSC)

Project type:
Enhanced Oil Recovery

Project scale :
Small scale (6,260 t)

Type and depth of reservoir:
Clore Sandstone, 585 meters

Total cost of project:
Individual site budgets not available

Location:
Posey County, Indiana, USA

Year of first injection:
2009

Current status:
Injection complete

Type of Seal:
Clore Shale

PROJECT DETAILS

	Project operator	Gallagher Drilling Inc.	**Project contact phone**	(217) 244-8389
	Project contact	Rob Finley	**Project contact email**	finley@isgs.uiuc.edu
	Project location	Posey County, Indiana, USA	**CO_2 source**	Commercial
	Injection site coordinates	38°11'50"N, 87°52'51"W	**CO_2 transport/delivery**	Truck
	Project planning start	2003	**Injection rate**	23-32 tonnes/day
	Duration of injection	8 months	**Injection pressure**	1,500 psi (regulated max)
	Planned injection volume	Not known	**Total volume injected**	6,260 tonnes
	Reservoir porosity	19%	**Reservoir permeability**	150mD
MONITORING	**Seismic monitoring**	Not performed	**Gravity studies**	Wellhead and downhole
	Water monitoring	Dedicated shallow wells	**Pressure logging**	Wellhead
	Soil monitoring	Not performed	**Thermal logging**	Not performed
	Atmospheric monitoring	Gas flux	**Wireline logging**	Case hole logs
	Ecological monitoring	Not known	**Observation well**	No dedicated wells
	Tracer analysis	dC13 of CH_4 and CO_2, dC14 of DIC, dO18	**Geochemical research/Fluid sampling**	Brine from 4 production wells: pH, ORP, EC, DO, anions, cations, TDS, TOC, alkalinity, dissolved CO_2
	Electromagnetic	Not performed	**InSAR**	Not performed
RESERVOIR STUDIES	**Reservoir modelling**	VIP	**Geologic model**	Project created
	Coring	Not performed	**Seismic**	Not performed
	Other technologies	Not known		

Project context

The Mumford Hills EOR II project was a test of miscible EOR at the Mumford Hills field in Posey County, Illinois.

The project was run by the Midwest Geological Sequestration Consortium (MGSC), part of the US Department of Energy (DoE) Regional Carbon Sequestration Partnerships (RCSP) initiative. The overall DoE program follows a three phase implementation. As a validation scale project, the project forms part of Phase II of the RCSP program evaluating promising CO_2 storage opportunities. MGSC has three phase II storage validation projects examining Enhanced Oil Recovery.

Aims of the project

The project aims to inject CO_2 into a prevalent Illinois Basin oil-bearing interval (or equivalent) to directly measure CO_2 sequestration mass, enhanced oil recovery, and CO_2 injection rate.

Ownership and liability

The project is owned by Gallagher Drilling, Inc, whereas the injection site and surrounding, transport-pipeline route approval are privately owned. The liability of the project lies with Gallagher Drilling, Inc.

Regulatory and approval conditions

CO_2 injection was in an existing oil producing well. A new UIC Class II permit was required for this project.

Pre-injection geological database and site characterisation

The Mississippian Clore sandstone was the target reservoir, a thick, elongated body of sandstone at approximately 585 meters deep and 10 meters thick. At the project site there is a small aquifer underlying the target reservoir, which is part of a small structure with stratigraphic pinch out and an overlying 6 meter oil column.

Source of CO_2

The CO_2 was purchased from a commercial source.

Transport of CO_2

Liquid CO_2 was transported to site with trucks and loaded into storage tanks held onsite.

Additional project details

The test was designed as an inverted 5 spot with one central CO_2 injection and four production wells. The injection of CO_2 began on September 3, 2009. CO_2 injection ended on May 3, 2010 after 6,300 tonnes of CO_2 had been injected. Injection rates were about 30-35 tonnes per day. CO_2 injection was to take 6-8 months followed by 3-5 months of water injection. Reservoir models calibrated to the pilot results indicated full field CO_2 enhanced oil recovery to be 12% of the original oil in place.

Stakeholder engagement

The Department of Energy expected the project to host an estimated 120 full-time jobs during the lifetime of the project.

Risk assessment process

The risk assessment was qualitative and predominantly applied during the site screening and selection process. The general approach was to understand potential risks during CO_2 injection by understanding historical oilfield operations at the sites and the current operators' role in the day to day activities of existing oil fields. Both pre- and post-injection sampling was carried out as part of a monitoring, verifying and accounting effort.

Significant learnings from the project

- Project achieved recommissioning of an abandoned well to increase oil production as a result of CO_2 and water injections.
- Having flowing production wells eliminated electrical costs of pumping wells.
- Oil production increased over the pre-injection rate.

PROJECT SUMMARY

Project name: MGSC Sugar Creek (EOR III) Phase II	**Total cost of project:** Individual site budgets not available
Project organisation: Midwest Geological Sequestration Consortium (MGSC)	**Location:** Hopkins County, Kentucky, USA
Project type: Enhanced Oil Recovery	**Year of first injection:** 2009
Project scale: Small (6,560 t)	**Current status:** Injection complete
Type and depth of reservoir: Jackson sandstone, 600 meters	**Type of Seal:** Fraileys shale

PROJECT DETAILS

	Project operator	Gallagher Drilling Inc.	**Project contact phone**	(217) 244-8389
	Project contact	Robert Finley	**Project contact email**	finley@isgs.uiuc.edu
	Project location	Hopkins County, Kentucky, USA	**CO_2 source**	Commercial
	Injection site coordinates	37°17'49'' N, 87°34'53'' W	**CO_2 transport/delivery**	Truck
	Project planning start	2005	**Injection rate**	18-27 tonnes/day
	Duration of injection	12 months	**Injection pressure**	1,425 psig
	Planned injection volume	7,270 tonnes	**Total volume injected**	6,560 tonnes
	Reservoir porosity	16%	**Reservoir permeability**	15-20md
MONITORING	**Seismic monitoring**	Not performed	**Gravity studies**	Not performed
MONITORING	**Water monitoring**	Dedicated shallow wells	**Pressure logging**	Wellhead (observations wells) Subsurface (injection well)
MONITORING	**Soil monitoring**	Not performed	**Thermal logging**	Temperature cased-hole logging
MONITORING	**Atmospheric monitoring**	Gas flux	**Wireline logging**	Case hole logs
MONITORING	**Ecological monitoring**	Not known	**Observation well**	No dedicated well
MONITORING	**Tracer analysis**	dC13 of CH4 and CO2, dC14 of DIC, dO18	**Geochemical research/Fluid sampling**	Brine from 8 production wells, pH, ORP, EC, DO, anions, cations, TDS, TOC, alkalinity, dissolved CO_2
MONITORING	**Electromagnetic**	Not performed	**InSAR**	Not performed
RESERVOIR STUDIES	**Reservoir modelling**	VIP	**Geologic model**	Project created
RESERVOIR STUDIES	**Coring**	Not performed	**Seismic**	Not performed
RESERVOIR STUDIES	**Other technologies**	Not known		

Project context

The Sugar Creek EOR III project is a shallow depth, immiscible, CO_2 flood EOR project, which took place in the Sugar Creek Field in Hopkins County, Kentucky in 2009 and 2010.

The project was carried out by the Midwest Geological Sequestration Consortium (MGSC), part of the US Department of Energy (DoE) Regional Carbon Sequestration Partnerships (RCSP) initiative. The overall DoE program follows a three phase implementation. As a validation scale project, the project forms part of Phase II of the RCSP program evaluating promising CO_2 storage opportunities. MGSC has three, phase II storage validation projects, examining Enhanced Oil Recovery.

Aims of the project

This project aims to inject CO_2 into a prevalent Illinois Basin oil-bearing interval (or equivalent) to directly measure CO_2 sequestration mass, enhanced oil recovery, and CO_2 injection rate.

Ownership and liability

The project is owned by Gallagher Drilling, Inc, whereas the injection site and surrounding, transport-pipeline route approval are privately owned. The liability of the project lies with Gallagher Drilling, Inc.

Regulatory and approval conditions

CO_2 injection was in an existing water injection well that had a current and valid UIC Class II permit for water injection. This permit was modified for CO_2 injection.

Pre-injection geological database and site characterisation

The Mississippian Jackson Sandstone, an oil-bearing interval, was the target formation. Numerical modelling was used to assess EOR and sequestration at large scale and to update Phase I research, conducted as part of the RCSP's CO_2 storage resource estimates for oil reservoirs. Part of a modest geologic structure, the target reservoir has a thickness of 1-6 meters with fair to poor communication.

Source of CO_2

The CO_2 was purchased from a commercial source.

Transport of CO_2

Liquid CO_2 was transported to site with trucks and loaded into storage tanks held onsite.

Additional project details

Between May 2009 and May 2010 approximately 6560 tonnes of CO_2 were injected into the Mississipian Jackson sandstone at immiscible conditions at ~564m (1850ft). Injection took place through a central injection well surrounded by 8 production wells. Injection rates were up to 30 tonnes per day. Reservoir models calibrated to the pilot results indicated fullfield CO_2 enhanced oil recovery to be 5.5% of the original oil in place.

Stakeholder engagement

Meeting with EMS and local officials.

Risk assessment process

The risk assessment was qualitative and predominantly applied during the site screening and selection process. The general approach was to understand potential risks during CO_2 injection by understanding historical oilfield operations at the sites and the current operators' role in the day to day activities of existing oil fields.

Significant learnings from the project

- Early breakthrough of CO_2 resulted in loss of production, adversely affecting direct field measurements of the EOR project
- At some Sugar Creek oil wells, in-zone geochemical monitoring shows significant change in CO_2 casing gas and brine chemistry prior to a significant pressure response.

PROJECT SUMMARY

Project name:
MGSC Tanquary site ECBM Phase II

Project lead organisation:
Midwest Geological Sequestration Consortium (MGSC)

Project type:
Enhanced Coalbed Methane

Project scale:
Small scale (<100,000 t)

Type and depth of reservoir:
Springfield coal, 275 meters

Total cost of project:
US$ 768,019

Location:
Wabash County, Albion, IL, USA

Year of first injection:
2008

Current status:
Injection complete

Type of Seal:
Dykersburg shale

PROJECT DETAILS

	Project operator	Gallagher Drilling, Inc.	**Project contact phone**	(217) 244-8389
	Project contact	Robert Finley	**Project contact email**	finley@isgs.uiuc.edu
	Project location	Albion, IL, USA	**CO_2 source**	Commercial (from Air Liquide)
	Injection site coordinates	38°22′38″N 88°3′40″W	**CO_2 transport/delivery**	Truck
	Project planning start	2005	**Injection rate**	0.5-1-5 tonnes/day
	Duration of injection	June 2008 – January 2009	**Injection pressure**	875 psia
	Planned injection volume	Up to 200 tonnes	**Total volume injected**	92.3 tonnes
	Reservoir porosity	1-3% (cleat porosity)	**Reservoir permeability**	5 md
MONITORING	**Seismic monitoring**	Not performed	**Gravity studies**	Not performed
	Water monitoring	Shallow groundwater monitoring	**Pressure logging**	Wellhead and downhole
	Soil monitoring	Not performed	**Thermal logging**	Not performed
	Atmospheric monitoring	Not known	**Wireline logging**	Cased hole logging (GR, USI, RST)
	Ecological monitoring	Vegetation baseline data	**Observation well**	3 dedicated monitoring wells
	Tracer analysis	Not known	**Geochemical research/Fluid sampling**	pH, alkalinity, isotopic signatures, gases, composition of groundwater
	Electromagnetic	Not performed	**InSAR**	Not performed
RESERVOIR STUDIES	**Reservoir modelling**	COMET3	**Geologic model**	Not known
	Coring	Extensive split barrel coring	**Seismic**	Not performed
	Other technologies	HighRes color-infrared aerial photography (for potential stress analysis)		

Project context

The MGSC Tanquary ECBM Phase II project was designed to test the CO_2 storage capacity and ECBM potential of the Illinois coal basin. The project, which was run by the Midwest Geological Sequestration Consortium (MGSC), is located in the Tanquary Field Wabash County and is part of the US Department of Energy (DoE) Regional Carbon Sequestration Partnerships (RCSP) initiative.

The overall DoE program follows a three phase implementation. As a validation scale project, the project forms part of Phase II of the RCSP program evaluating promising CO_2 storage opportunities. MGSC has four phase II storage validation projects, three examining enhanced oil recovery and this project, examining enhanced coalbed methane (ECBM).

Aims of the project

The Tanquary ECBM project aims to measure the changes in CO_2 injectivity of Illinois Basin coal, the amount of CO_2 that is retained by the coal, and the amount of methane gas that is displaced by CO_2.

Ownership and liability

Project ownership: Gallagher Drilling, Inc.

Land ownership – injection site and surrounding, transport-pipeline route approval: Privately owned

Liability: Gallagher Drilling, Inc

Regulatory and approval conditions

Ground water protection requirements for the injection permit within an 800 meter radius are applicable to the project and enforced through the injection permitting process.

The injection was considered an enhanced gas recovery pilot and a UIC Class II permit was required.

Pre-injection geological database and site characterisation

The target coal seam, which was the Springfield coal of the Carbondale formation, is of a highly volatile, bituminous rank. This coal has well developed cleats with 1-2cm spacing with a calcite and/or kaolinite filling.

Cores from the observation wells were taken for extensive characterisation because coal maceral composition influences CO_2 adsorbtion. Tests were conducted and analysed gas content, gas chemistry and multi-gas (CH_4, CO_2CO_2 N_2) adsorption testing, coal shrinkage and swelling factor with CH4 desorption or CO_2 adsorption.

Drill stem tests were conducted on the Springfield coal interval from each of the wells giving estimates of permeability and skin factor. Open hole logs (types: SP, resistivity, high resolution GR-Compensated Neutron/Density, and Full Wave Sonic) were run in each well.

The wells were cased and cemented from TD to surface, then perforated in the Springfield Coal interval at about 275 meters deep. Water injection tests with pulse and pressure fall-offs showed communication in all wells and contributed properties to the COMET coal simulation models to establish the pre-CO_2 injection baseline.

Source of CO_2

The CO_2 was purchased from a commercial source.

Transport of CO_2

CO_2 was transported to site by truck.

Additional project details

Starting in June 2008, several CO_2 injection and shut-in periods began. Following this, continuous injection took place until methane and/or carbon dioxide break through occurred at all three observation/monitoring wells.

Stakeholder engagement

None.

Risk assessment process

The risk assessment was qualitative and predominantly applied during the site screening and selection process. The general approach was to understand potential risks during CO_2 injection by understanding historical oilfield operations at the sites and the current operators' role in the day-to-day activities of existing oil fields.

Significant learnings from the project

- CO_2 adsorbed in-situ, methane and CO_2 moved more readily in butt cleat direction compared to face cleat direction.
- Modest to no reduction in injection rate attributable to CO_2 swelling, no CO_2 detected out of the injection zone.
- No out of zone CO_2 was detected or significant CO_2 produced.
- Fracture gradient increased in injection well after CO_2 injection.

PROJECT SUMMARY

Project name:
Mountaineer Product Validation Facility (PVF)

Total cost of project:
>$100 million including capture system

Project organisation:
American Electric Power Service Corporation

Location:
Mason County, West Virginia, USA

Project type:
Deep Saline Aquifer

Year of first injection:
2009

Project scale:
Small scale (~37,000 tonnes)

Current status
Post injection monitoring since May 2011

Type and depth of reservoir:
Cambro-Ordovician sandstone and carbonates >2470m

Type of Seal:
Shales and Carbonates

PROJECT DETAILS

	Project operator	American Electric Power (AEP)	**Project contact phone**	(614) 716-1076
	Project contact	Indra Bhattacharya (AEP); Neeraj Gupta (Battelle)	**Project contact email**	ibhattacharya@aep.com gupta@battelle.org
	Project location	Mason County, West Virginia, USA	**CO_2 source**	Mountaineer Coal Fired Power Plant
	Injection site coordinates	38°58'24" N, 81°56'13"W	**CO_2 transport/delivery**	Pipeline (<1 km)
	Project planning start	2003	**Injection rate**	50-100 tpd
	Duration of injection	18 mths, 2009-11,	**Injection pressure**	1300 psi (limit)
	Planned injection volume	Initially 100,000 tonnes/year for 4 years	**Total volume injected**	~37,000 tonnes
	Reservoir porosity	4.1% to 13% (Rose Run)	**Reservoir permeability**	Avg ~72.5mD up to 800mD in high permeability zones (Lower Copper Ridge) Avg ~1.9mD up to 10 mD (Rose Run)
MONITORING	**Seismic monitoring**	Crosswell	**Gravity studies**	None
	Water monitoring	Shallow groundwater wells	**Pressure logging**	Wellhead and downhole
	Soil monitoring	None	**Thermal logging**	Wellhead and downhole
	Atmospheric monitoring	None	**Wireline logging**	Pulsed Neutron Capture
	Ecological monitoring	None	**Observation well**	3 dedicated deep monitoring wells
	Tracer analysis	None	**Geochemical research/Fluid sampling**	Brine geochemistry
	Electromagnetic	None	**InSAR**	Not performed
RESERVOIR STUDIES	**Reservoir modelling**	STOMP-CO_2	**Geologic model**	PETRA, PETRASEIS, PETREL
	Coring	Full or sidewall coring in two wells	**Seismic**	New 2D in 2003
	Other technologies	Not known		

Project context

The Mountaineer Product Validation Facility (PVF) was used as a proof of concept for carbon dioxide capture, transportation and sequestration at a coal fired power plant for the first time in world. Two injection wells and three monitoring wells were used. The targeted formations were the Cambrian-Ordovician Rose Run Sandstone and Copper Ridge Dolomite.

The Alstrom Chilled Ammonia Plant, operated successfully between 2009 and 2011, capturing CO_2 (at rates of up to 100,000 tpa) and storing of 37,000 tonnes in two zones within the target reservoir section

Aims of the project

The aim of the project was to validate the technology of Alstom's chilled ammonia process for CO_2 capture from a coal-fired power plant with injection and geological storage of the CO_2 in two reservoirs.

Ownership and liability

The projects design, construction and operation were led by *American Electric Power Service Corporation (AEP),* who also own the injection site.

Regulatory and approval conditions

There were a series of well work permits from the State of West Virginia Department of Environmental Protection Office (WV DEP) of Oil and Gas required in the project. USEPA Class V experimental injection permits were granted by WVDEP under the underground injection control program.

Pre-injection geological database and site characterisation

As part of a DOE funded project in 2003, the geologic background at the Mountaineer site was investigated by Battelle This study included the drilling of a characterisation well and acquisition of two 2D seismic lines near the potential sequestration site at the Mountaineer plant.

Along with this study, a regional scale geologic study was also conducted by the Ohio Geologic Survey which focused on prospective storage reservoirs for CO_2 sequestration. The Ohio River Valley project at Mountaineer identified two potential geologic formations of Cambro-Ordovician Age for CO_2 sequestration including the Rose Run Formation- a sandstone, and a thin zone in the Copper Ridge (lower copper ridge) Formation - carbonate.

The geochemical signatures of the brine from these two formations were similar with total dissolved solids (TDS) of greater than 300,000 mg/L.

The stratigraphy shows the presence of several shale units (combined thickness >1500ft) as well as dolomite and limestone units (such as the Wells Creek dolomite, the Black River Limestone, the Trenton lime) provide excellent containment or "cap rock".

One injection well and three deep monitoring wells were drilled within the power plant property between 2008 and 2009, and the characterization well, which was drilled in 2003 was re-worked and transformed into a second injection well. The majority of the sub-surface information in this region was obtained from the five PVF wells and associated operational data. Total CO_2 injected during PVF Pilot project was 27,176.7 tonnes in Copper Ridge and 10,226.6 tonnes into the Rose Run Formation.

Source of CO_2

The CO_2 was captured at the Mountaineer coal fired power plant, from a slip stream of flue gas from the main stack using Alstom's chilled ammonia technology.

Transport of CO_2

From the capture plant, the CO_2 was transported via <1 km of pipeline to the injections wells.

Additional project details

The Mountaineer plant region is not a part of an active oil and gas exploration/production region hence there is a substantial lack of deep subsurface data (both deep well and surface seismic data). The project relies on the work completed during the previous projects mentioned above.

CO_2 injection into the sandstone and carbonate formations started in November, 2009 and injection ceased at the end of May 2011 during the PVF pilot project. The PVF met all the project goals during 18 months of injection.

The injection was not continuous for this entire period of operation primarily due to planned outages of the Mountaineer main unit, the CO_2 capture unit and planned well work over activity. Injectivity was excellent for the Copper Ridge dolomite formation and was below expectation for the Rose Run sandstone. This led to the conclusion that the Copper Ridge dolomite was the preferred target reservoir for CO_2 sequestration at this location.

The total cost of pre-PVF work is estimated at more than $7M. The PVF project cost was more than $100M including capture.

Active injection finished in May 2011

Stakeholder engagement

The project was required to submit an Environmental Impact Statement for public comment prior to constructions. While the EIS was on display, public were encouraged to make submissions before all public concerns were collected and addressed. Activities related to communication and public outreach included:

- Meetings with regulatory authorities and project managers
- Information presentations to public
- Local town hall and community leader meetings
- Outside stakeholders

Risk assessment process

An initial larger scale risk assessment was completed for the storage of CO_2 at Mountaineer in 2008, as part of the Ohio River Valley CO_2 Storage project.

Early in the project planning, risks and opportunities were examined by the project team. The risks were qualitatively ranked for probability of occurrence, impact and severity. Following this action, plans or best practices were employed as part of risk management with the goal of reducing the potential impact/issues severity in a managed state. During the project this was revisited on a quarterly basis.

Significant learnings from the project

- It is essential to communicate effectively and develop a working relationship with regulatory authorities early in the process. Based on experience with other CO_2 projects, increased cooperation makes the permitting process much easier planning for adequate time up front for regulatory delays and difficulties is important.
- Since the CO_2 injection and monitoring wells are not "for the extraction of oil and gas", they may come under a different regulator regime than standard oil and gas wells.
- Property and mineral rights ownership searches should be done during site selection process. Mineral rights can be passed down from family member to family member, often leading to multiple owners
- Sub-surface geology has a higher uncertainty compared to the capture and transportation aspects of a CCS project although the capital and O&M cost of the capture plant is much higher than the sequestration aspects

PROJECT SUMMARY

Project name:
MRCSP Appalachian Basin (Burger) Phase II

Project organisation:
Midwest Regional Carbon Sequestration Partnership (MRCSP) led by Battelle in Columbus, Ohio

Project type:
Deep Saline Aquifer

Project scale
Small scale (<50 t)

Type and depth of reservoir:
Sandstone and carbonate, 1982 meters

Total cost of project:
Individual site budgets not available

Location:
Shadyside, Ohio, USA

Year of first injection:
2008

Current status:
Injection complete

Type of Seal:
Shale

PROJECT DETAILS

	Project operator	Battelle	**Project contact phone**	(614)-424-3820
	Project contact	Neeraj Gupta	**Project contact email**	gupta@battelle.org
	Project location	Shadyside, Ohio, USA	**CO_2 source**	Commercial
	Injection site coordinates	39°55'25"N, 80°45'18"W	**CO_2 transport/delivery**	Truck
	Project planning start	October 2005	**Injection rate**	8 to 49 tonnes/day
	Duration of injection	2 months	**Injection pressure**	Up to 4400 psi (Salina)
	Planned injection volume	3000 tonnes	**Total volume injected**	less than 50 tonnes
	Reservoir porosity	2-6% (Oriskany) 0-12% (Salina) 2-6% (Clinton)	**Reservoir permeability**	NA-0.003 mD (Oriskany) 0.003-0.370 mD (Salina) 0.002-0.22 mD (Clinton)
MONITORING	**Seismic monitoring**	Not performed	**Gravity studies**	Not performed
	Water monitoring	Not performed	**Pressure logging**	Wellhead and downhole
	Soil monitoring	Not performed	**Thermal logging**	Wellhead and downhole
	Atmospheric monitoring	Not performed	**Wireline logging**	Pulsed Neutron Capture (pre-injection only, no repeat monitoring)
	Ecological monitoring	Not performed	**Observation well**	Not performed
	Tracer analysis	Not performed	**Geochemical research/Fluid sampling**	Not performed
	Electromagnetic	Not performed	**InSAR**	Not performed
RESERVOIR STUDIES	**Reservoir modelling**	Hydraulic analysis (modified Horner method)	**Geologic model**	Conceptual
	Coring	Rotary sidewall cores	**Seismic**	2D Surface
	Other technologies	Not known		

Project context

This project provided an opportunity to evaluate the feasibility of injecting CO_2 into three different deep rock formations (i.e., Oriskany Sandstone, Salina Carbonate, and Clinton/Medina Sandstone) at depths from 1800 to 2500 meters below the surface. These formations are pervasive across the Appalachian Valley, a region that contains many major coal-fired power plants. FirstEnergy's R.E. Burger Power Plant located in Shadyside, Ohio was also host to a separate test of the Powerspan CO_2 capture process called ECO2. Initially, the concept was to test an integrated CO_2 capture, handling, and injection system by integrating the CO2 injection test with the Powerspan test. Schedules of the two projects did not allow that to happen; as a result, the injection test was conducted with commercial CO_2.

The Midwest Regional Carbon Sequestration Partnership (MRCSP) is one of seven Regional Carbon Sequestration Partnerships in the US, developed in an effort to determine regionally-appropriate carbon sequestration options and opportunities. These partnerships are part of a broader initiative run by the U.S. Department of Energy's (DOE's) National Energy Technology Laboratory (NETL) to develop robust strategies for mitigating CO_2 emissions. The program is being implemented in three phases: (1) Characterisation Phase (2003–2005); (2) Validation Phase (2005–2011); and (3) Development Phase (2008–2018+). This project was one of three Validation Phase (Phase II) field tests conducted by MRCSP.

Aims of the project

To explore geologic storage targets in this area of the Appalachian Basin geologic province and develop CO_2 sequestration technology through drilling of a deep test well and conducting CO_2 injection tests. The project also had a strong emphasis on advancing CO_2 sequestration technology through public outreach and education.

Ownership and liability

Issues such as subsurface property rights and long-term liability were not directly addressed by the small-scale validation tests. The project was led by Battelle. The project host was FirstEnergy and the entire project took place on the host site property.

Regulatory and Approval Conditions

The permits required included a well drilling permit and the underground injection control (UIC) permit. The test well was first permitted as a stratigraphic test well with the Ohio Department of Natural Resources Division of Mineral Resource Management. An UIC Class V permit was obtained under the Ohio Environmental Protection Authority (EPA) UIC program. Part of approval required daily notification of activities to Ohio EPA during injection and monthly reports summarising maximum injection pressure, annular pressure, injection rates, and total injection volumes.

Pre-injection geological database and site characterisation

A collaborative, regional geologic assessment was developed by the Ohio, Pennsylvania, and West Virginia Geological Surveys, describing the regional geologic setting and target sequestration rock formations by June 2006. Site characterisation, well design, a two-dimensional (2D) seismic survey, and the drilling of a test well of just over 2500 meters depth were completed by February 2007. A full program of mud logging, wireline logging, sidewall coring, core testing, and petrophysical analysis was completed to characterise the geologic units. Following evaluation, porosity and permeability of target storage formations were seen to be lower than expected, strengthening the importance of extensive drilling, formation evaluation, and characterisation efforts to identify suitable formations for the geologic storage of CO_2 in more complex basins such as the Appalachian.

Source of CO_2

A commercial source of CO_2 was used for the injection tests.

Transport of CO_2

The liquid CO_2 was delivered in tanker trucks carrying about 20 tons of CO_2 each from the *Praxair Marmet*, West Virginia facility to the R.E. Burger injection site. Three 50 ton mobile storage tanks set up on the R.E. Burger site provided an interim holding system before injection.

Additional project details

Injection took place from September 24, 2008 through November 22, 2008. The Appalachian Basin test, FirstEnergy's R.E. Burger Power Plant was chosen as a test site because of its central location to one of the nation's major power generation corridors, the Ohio River Valley, and because it was expected to provide access to geologic formations having significant expected storage capacity across the region. All three formations were found to have very low injectivity, at this site. Although less than 50 metric tons of CO2 was injected, validation scale testing into the complex and heterogeneous geological regions like the northern Appalachian Basin helped establish familiarity with CO_2 sequestration technologies in the region. It provided important deep well data points in a strategically valuable portion of the MRCSP region that may hold promise for geologic storage, but requires more characterisation for mapping and quantification of storage potential.

Stakeholder engagement

The project followed a gradual process for public engagement building awareness and acceptance over time. Stakeholder engagement involved the following activities:

- Establishing a team approach to coordinate planning and implementation.
- Identifying the technical milestones and regulatory requirements.
- Identifying key stakeholders (i.e., individuals and groups affected by and/or interested in the project, industry and state government).
- Initiating communication between team members and members of the public to identify viewpoints, issues of concern and preferred methods of communication.
- Developing a variety of opportunities for learning and information sharing.
- Preparation of information materials (fact sheets, interactive models, hands-on displays, PowerPoint briefings, and posting of project snapshots on the MRCSP web site).
- Preparing for media interest, developing an educational video of the drilling program as part of their teacher education program on energy.
- Organisation of an informal public educational meeting, as well as participation at the Ohio EPA UIC permitting hearing.
- Conducting broader research to identify factors that shape public acceptability and the long-term viability of geologic sequestration.
- In general, the project received little opposition, likely due to its importance towards the local economy as well as familiarity with oil and gas operations in the area.

Risk assessment process

The risk mitigation approach was implementing a deliberate, thoroughly planned and vetted sequential stepwise program that put safety above all else. MRCSP performed site-specific risk assessment modeling and analyses to identify risks and develop risk mitigation scenarios. During the course of the field validation test, the MRCSP developed site-specific action plans that outlined and satisfied Federal National Environmental Policy Act (NEPA) requirements and project permitting requirements for each of the major system components of the geologic field tests, including transport, seismic survey, drilling, injection, well closure, and site restoration.

Significant learnings from the project

- Although injectivity at this site was less than expected the test did help establish familiarity with CO_2 sequestration technologies in the region and provided a much needed deep well data point in a strategically important region.
- The test highlighted the variability of geological environments especially in the deep and complex Appalachian Basin.
- The Burger test along with the other Phase II MRCSP tests showed that characterisation methods such as core tests, wireline logging and geologic logging may only provide indicators of injectivity. True injectivity needs to be proven with field injection tests.
- This site highlights the value of small scale research oriented tests, which allow valuable experience to be gained in site characterisation, permitting, infrastructure implementation and injection testing with significantly less capital investment compared to full scale application.

With the lessons learned from this site, Battelle has continued the regional exploration of geologic storage targets in the northern Appalachian Basin under MRCSP and Ohio Coal Development Office funded projects. This includes logging, coring, and testing various intervals in wells being drilled by oil production and brine disposal companies.

PROJECT SUMMARY

Project name:
MRCSP Cincinnati Arch (East Bend) Phase II

Project lead organisation:
Midwest Regional Carbon Sequestration Partnership (MRCSP) led by Battelle in Columbus, Ohio

Project type:
Deep Saline Aquifer

Project scale
Small scale (910 t)

Type and depth of reservoir:
Sandstone, 975 meters

Total cost of project:
Individual site budgets not available

Location:
Rabbit Hash, Kentucky, USA

Year of first injection:
2009

Current status:
Injection complete

Type of Seal:
Mixture of dolomite and shale

PROJECT DETAILS

	Project operator	Battelle	**Project contact phone**	(614)-424-3820
	Project contact	Neeraj Gupta	**Project contact email**	Gupta@battelle.org
	Project location	Rabbit Hash, KY, USA	**CO_2 source**	Commercial source
	Injection site coordinates	38°53'33"N, 84°50'42"W	**CO_2 transport/delivery**	Truck
	Project planning start	2006	**Injection rate**	Varied –max reached was 1200 tonnes/day – avg 405 tpd
	Duration of injection	One week	**Injection pressure**	1600 to 1900 psi
	Planned injection volume	3,000 tonnes	**Total volume injected**	910 tonnes
	Reservoir porosity	5-15%	**Reservoir permeability**	0-100mD (varies over the formation)
MONITORING	**Seismic monitoring**	Baseline VSP	**Gravity studies**	Not performed
	Water monitoring	11 shallow wells	**Pressure logging**	Wellhead and downhole
	Soil monitoring	Not performed	**Thermal logging**	Wellhead and downhole
	Atmospheric monitoring	Not performed	**Wireline logging**	Salinity, sonic, saturation, resistivity
	Ecological monitoring	Not performed	**Observation well**	Not performed
	Tracer analysis	Not performed	**Geochemical research/Fluid sampling**	CO_2, HCO_3, CO_3, major ions, trace elements, salinity
	Electromagnetic	Not performed	**InSAR**	Not performed
RESERVOIR STUDIES	**Reservoir modelling**	STOMPCO2	**Geologic model**	Conceptual
	Coring	120ft plus sidewall cores	**Seismic**	2D surface, VSP
	Other technologies	Not known		

Project context

This project was a field demonstration of the injection of approximately 1000 tonnes of CO_2 into the Cambrian-aged Mt. Simon Sandstone at Duke Energy's East Bend Generating Station at Rabbit Hash Kentucky. The Mt. Simon has the largest potential storage capacity in the region and one of the largest potential storage reservoirs in the US. This was the first known injection test into the Mount Simon for purposes of qualifying storage potential.

The Midwest Regional Carbon Sequestration Partnership (MRCSP) is one of seven Regional Carbon Sequestration Partnerships in the US, developed in an effort to determine regionally-appropriate carbon sequestration options and opportunities. These partnerships are part of a broader initiative run by the U.S. Department of Energy's (DOE's) National Energy Technology Laboratory (NETL) to develop robust strategies for mitigating CO_2 emissions. The program is being implemented in three phases: (1) Characterisation Phase (2003–2005); (2) Validation Phase (2005–2011); and (3) Development Phase (2008–2018+). This project was one of three Validation Phase (Phase II) field tests conducted by MRCSP.

Aims of the project

To demonstrate CO_2 sequestration in the Mt. Simon Sandstone, a major CO_2 sequestration target for the MRCSP region. In addition to the main objective, the tests are aimed at better understanding regional trends (i.e. permeability, porosity, geochemistry, mineralogy) in the Mt. Simon Sandstone. The project also had a strong emphasis on advancing CO_2 sequestration technology through public outreach and education.

Ownership and liability

Issues such as subsurface property rights and long-term liability were not directly addressed by the small-scale validation tests. The project was led by Battelle. The project host was Duke Energy and the entire project took place on the host site property.

Regulatory and approval conditions

An Underground Injection Control (UIC) Class V injection permit was required for the project, pursued under US EPA Region 4 UIC program. The project also had to obtain a permit to drill the test well from the Kentucky Division of Oil and Gas Conservation.

Pre-injection geological database and site characterisation

Mt. Simon Sandstone was chosen as the target formation for the CO_2 injection. A 2D seismic survey was conducted to assess the geology in the vicinity of the site and to look for faulting and other structural features that could adversely affect the site's ability to permanently store CO_2.

The test well was drilled to a depth of approximately 1125 meters. Rock samples were collected from the storage and caprock formations. Wireline tools were used to measure and collect geophysical properties such as sonic velocities, density, porosity, and resistivity. Geochemistry of the brine within the storage formation was determined by swabbing the perforated well and collecting brine samples for laboratory analysis. The hydraulic properties of the storage reservoir were tested during short-term brine injection. High resolution images near the wellbore were taken using vertical seismic profile (VSP).

At the East Bend site, the Mt. Simon Sandstone occurs between depths of 985 and 1076 meters below ground (thickness of 92 meters) and is overlain by approximately 137 meters of the Eau Claire Formation. The porosity of the Mt. Simon Sandstone determined from wireline logs is primarily 5 to 15%, but intervals with <5% and >15% porosity were also encountered. Permeability based on wireline data calibrated to core data indicates that one-third of the formation is between 0 and 10 millidarcies (mD); one-third is between 10 and 100 mD; and one-third is 100 mD or greater.

The Eau Claire Formation exhibits excellent properties for a caprock, including substantial thickness, permeability generally less than 1 mD, and an absence of fractures and faulting that could compromise its sealing ability.

Source of CO_2

The CO_2 was purchased from a commercial source.

Transport of CO_2

CO_2 was transported to the site by truck.

Additional project details

A CO_2 injection rate on the order of 5 barrels per minute (bpm) was achieved during the injection test, but this rate was limited by the pumping equipment used, not the injectivity of the formation. This rate is approximately equivalent to 1,200 tonnes/day or approximately 0.5 million tonnes per year. A 2D numerical model of the Mt. Simon Sandstone was constructed based on geologic characterisation data collected during the project and used to simulate the brine injection test and the CO_2 injection test.

Periodic groundwater monitoring of underground sources of drinking water was required by the UIC permit. Groundwater samples were collected from 10 monitoring wells in the vicinity of the demonstration site on a quarterly basis for two years following injection, including a new groundwater monitoring well that was installed 122 meters from the injection well. These wells were screened at various depths, ranging between 20 and 50 meters below the ground surface.

Stakeholder engagement

The project helped establish familiarity with carbon sequestration among stakeholders in the region. A proactive public outreach program ran throughout the duration of the project aiming to educate and inform stakeholders and facilitating successful project implementation. The project's key engagement activities included:

- Introduction of project via "Dear Neighbour" letter.
- Open house public meetings with exhibits and one-and-one discussions.
- Information materials distributed to stakeholders and made available online.
- Briefings to local government officials and to the Kentucky Service Commission.
- Media engagement (newspaper interviews and press releases).
- Project tour for the MRCSP members.
- Website with a series of photographs, accompanied by a brief summary of site activities, to tell the project story.

Risk assessment process

The risk mitigation approach was implementing a deliberate, thoroughly planned and vetted sequential stepwise program that put safety above all else. MRCSP performed site-specific risk assessment modeling and analyses to identify risks and develop risk mitigation scenarios. During the course of the field validation test, the MRCSP developed site-specific action plans that outlined and satisfied Federal National Environmental Policy Act (NEPA) requirements and project permitting requirements for each of the major system components of the geologic field tests, including transport, seismic survey, drilling, injection, well closure, and site restoration.

Significant learnings from the project

- Small-scale projects are important because they assist the development of site-specific monitoring and assessment programs that meet regulatory and public expectations, and provide confidence that larger scale applications can also be implemented very successfully
- This test confirmed the expected good injectivity of the Mt. Simon Sandstone in the Cincinnati Arch. This was the first CO_2 injection test into the Mt. Simon Sandstone.
- The project provides characterisation data for the Mt. Simon Formation that will be useful in helping to better understand the regional variability and trends in properties relevant to CO_2 sequestration, including porosity, permeability, and geochemistry.
- Conducting a brine injection test prior to injecting CO_2 was found to be a useful indicator of the ability of the formation to accept CO_2. In this test, injecting CO_2 resulted in much lower bottom-hole pressures than injecting a similar amount of brine – which suggests that brine injection tests provide a conservative estimate of the formation's CO_2 injectivity.

Furthermore, conducting a brine injection test and a CO_2 injection test in the same well provided corroborative data sets that were useful for characterising key hydraulic parameters of the reservoir (e.g., permeability, transmissivity) and for calibrating numerical models for evaluating CO_2 injection scenarios.

PROJECT SUMMARY

Project name:
MRCSP Michigan Basin Phase II

Project organisation:
Midwest Regional Carbon Sequestration Partnership (MRCSP) led by Battelle in Columbus, Ohio

Project type:
Deep Saline Aquifer

Project Scale:
Small scale (60,000 t)

Type and depth of reservoir:
Dolomite, 975 meters

Total cost of project:
Individual site budgets not available

Location:
Otsego County, Michigan USA

Year of first injection:
2008

Current status:
Injection complete

Type of Seal:
Dense, tight limestone

PROJECT DETAILS

	Project operator	DTE Energy/Core Energy	**Project contact phone**	(614) 424-3820
	Project contact	Neeraj Gupta	**Project contact email**	gupta@battelle.org
	Project location	Otsego County, Michigan, USA	**CO_2 source**	Gas Processing
	Injection site coordinates	45°02'40"N, 84°28'52"W	**CO_2 transport/delivery**	Pipeline (12km)
	Project planning start	2006	**Injection rate**	400-600 tonnes/day
	Duration of injection	1st injection = 3 weeks 2nd injection = 3 months	**Injection pressure**	950 psi
	Planned injection volume	10,000 tonnes	**Total volume injected**	1St 10,000 tonnes, 2nd 50,000 tonnes
	Reservoir porosity	21%	**Reservoir permeability**	22mD
MONITORING	**Seismic monitoring**	Crosswell and microseismic	**Gravity studies**	Not performed
	Water monitoring	Not performed	**Pressure logging**	Wellhead and downhole
	Soil monitoring	For tracer	**Thermal logging**	Wellhead and downhole
	Atmospheric monitoring	For tracer	**Wireline logging**	Cased hole, Pulsed Neutron Capture
	Ecological monitoring	Not performed	**Observation well**	2 dedicated deep wells
	Tracer analysis	Perfluorocarbon (PFC)	**Geochemical research/ Fluid sampling**	Brine and gas sample analyses
	Electromagnetic	Not performed	**InSAR**	Not performed
RESERVOIR STUDIES	**Reservoir modelling**	STOMPCO2	**Geologic model**	Conceptual
	Coring	55m	**Seismic**	2D
	Other technologies	Not known		

Project context

This small scale injection test focused on the injection of CO_2 into the Bass Islands Dolomite and adjacent Bois Blanc deep saline formations within the northern Michigan Basin. The site was located in Otsego County, Michigan, in the vicinity of an enhanced oil recovery (EOR) field operated by Core Energy, LLC. Much of the infrastructure for the demonstration was already present at the site, including CO_2 compressors, pipeline, injection systems, and existing wells for monitoring research. One of these existing wells was converted to a monitoring well. A new injection well was drilled. The CO_2 was supplied from natural processing plants, including a facility owned by DTE Energy at the time of the injection test.

The Midwest Regional Carbon Sequestration Partnership (MRCSP) is one of seven Regional Carbon Sequestration Partnerships in the US, developed in an effort to determine regionally-appropriate carbon sequestration options and opportunities. These partnerships are part of a broader initiative run by the U.S. Department of Energy's (DOE's) National Energy Technology Laboratory (NETL) to develop robust strategies for mitigating CO_2 emissions. The program is being implemented in three phases: (1) Characterisation Phase (2003–2005); (2) Validation Phase (2005–2011); and (3) Development Phase (2008–2018+). This project was one of three Validation Phase (Phase II) field tests conducted by MRCSP.

Aims of the project

The aim of this project was to test CO_2 sequestration in deep saline rock formations within the Michigan Basin. Several monitoring-related research hypotheses were examined as part of the DOE/NETL National Carbon Sequestration Partnership Monitoring Working Group.

Ownership and liability

Issues such as subsurface property rights and long-term liability were not directly addressed by the small-scale validation tests. The project was led by Battelle. The injection well and associated infrastructure was owned and operated by Core Energy and the CO_2 was a by-product of DTE Energy's natural gas processing operations at the time.

Regulatory and approval conditions

Permitting authorities were the US Environmental Protection Agency (EPA) Region 5 and the State of Michigan. The project required well drilling permits and an Underground Injection Control (UIC) Class V permit. The UIC permit was delayed as a result of a neighbouring landowner's appeal based on contesting property rights for injection; the appeal was denied because it was deemed outside the scope the US EPA Region 5's UIC permitting process. On completion of the research project, Core Energy applied to EPA Region 5 to convert the well into a Class II injection well. No permits were required for the pipeline extension because it was considered a short branch off the existing main CO_2 supply line.

Pre injection geological database and site characterisation

Site characterisation efforts included a preliminary geological assessment, drilling a test well - which was later permitted as the injection well, full rock coring through the injection zone and portions of the confining zone, core testing and wireline logging. The initial geologic assessment based on available well logs suggested that the Sylvania Sandstone would be the best potential injection zone within the depth range of interest. After drilling the test well, however, the Sylvania Sandstone was found to pinch out to the south of the project location and it was concluded that the Bass Islands Dolomite provided the best injection zone within the depth range of interest.

The test well was drilled in 2006 to a depth of 1066 meters. Approximately 55 meters of full rock core were collected. The rock core for the Bass Islands showed porosity of 13% and permeability of 22 mD across the 22 meter thick target injection zone. The immediately overlying Bois Blanc Formation showed features intermediate between an injection zone and a confining zone. Wireline logging and rock cores also characterised and confirmed properties of the overlying confining zone, which showed porosity of less than 5% and permeability less than the detection limits of the instrument. Amherstburg and Lucas Formations were identified as the confining zones.

Source of CO_2

The CO_2 was produced as a by-product from the Antrim natural gas wells. After the natural gas and CO_2 is separated, the CO_2 is either vented or sold to Core Energy for EOR.

Transport of CO_2

CO_2 was transported 12 km to site via commercial pipelines.

Additional project details

The MRCSP Michigan Basin Phase II project included two injection tests into the Bass island injection zone. The first test saw the injection of 10,000 tonnes of CO_2 over a period of about three weeks in February and March, 2008. The second test took place from mid-February through July 2009 and included injection of 50,000 tonnes of CO_2. Two existing oil wells were used for monitoring, including a nearby plugged oil well which was recompleted for use as a project monitoring well.

Stakeholder engagement

The project followed an outreach program integrally linked with the scientific and regulatory tasks of the project. An outreach plan was developed to link outreach activities to technical activities as the research project progressed. The purpose of the plan was to ensure that the participants involved in the test were coordinated with each other in conducting outreach activities. The outreach effort was ultimately aimed at building a solid foundation of public awareness of this test and for the longer-term implementation of geologic sequestration in the region. Major outreach tasks included production of informational factsheets, informal public informational meetings, site tours, and press releases. In general, the project was well received with little opposition, which was expected due to the prevalence of oil and gas, EOR and natural gas processing in the region and their importance to the local economy.

Risk assessment process

The risk mitigation approach was implementing a deliberate, thoroughly planned and vetted sequential stepwise program that put safety above all else. MRCSP performed site-specific risk assessment modeling and analyses to identify risks and develop risk mitigation scenarios. During the course of the field validation test, the MRCSP developed site-specific action plans that outlined and satisfied Federal National Environmental Policy Act (NEPA) requirements and project permitting requirements for each of the major system components of the geologic field tests, including transport, seismic survey, drilling, injection, well closure, and site restoration.

Significant learnings from the project

- Bass Islands Dolomite in northern Michigan Basin has suitable injectivity for CO_2 sequestration at an industrial scale, on the order of several hundred thousand metric tons per year in one well. This is better than the expected injectivity in this carbonate formation. Prior to this test carbonates were not considered to have significant sequestration potential in the region.
- Well tests proved useful in analysing injection potential, even though the maximum injection rates were not approached.
- Injection test analysis was used to define the hydraulic behaviour of the reservoir system in terms of flow behaviour and leakage.
- Reservoir simulations provide fairly accurate predictions of hydraulic response to injection.

Pressure/temperature data from injection were useful in evaluating hydraulic parameters and developing a site model. Time-lapse data from cross-well seismic imaging operations were useful in identifying CO_2 migration mechanisms in a complex dolomite reservoir. Data from wireline pulsed neutron capture logs, cement evaluation, and fluid sampling were consistent with cross-well seismic observations.

PROJECT SUMMARY

Project name:
Nagaoka Pilot CO_2 Storage Project

Project organisation:
Research Institute of Innovative Technology for the Earth (RITE)

Project type:
Deep Saline Aquifer

Project scale:
Small scale (~10,400 t)

Type and depth of reservoir:
Sandstone saline aquifer, 1100m

Total cost of project:
$32,000,000

Location:
Nagaoka-city, Niigata Prefecture, Japan

Year of first injection:
2003

Current status:
Injection completed in Jan 2005 and post-monitoring ongoing

Type of seal:
Mudstone (Haizume Formation)

PROJECT DETAILS

	Project operator	RITE	**Project contact phone**	81-774-75-2312
	Project contact	Ziqiu Xue	**Project contact email**	xue@rite.or.jp
	Project location	Nagaoka, Niigata Prefecture, Japan	**CO_2 source**	Food grade source
	Injection site coordinates	37°27'36"N, 138°50'26"E	**CO_2 transport/delivery**	Truck
	Project planning start	2000	**Injection rate**	20-40 tonnes/day
	Duration of injection	1.5 years	**Injection pressure**	12 MPa
	Planned injection volume	10,000 tonnes	**Total volume injected**	Approx 10,400 tonnes
	Reservoir porosity	23%	**Reservoir permeability**	7 md
MONITORING	**Seismic monitoring**	3D, Crosswell, Micro	**Gravity studies**	Not performed
	Water monitoring	Formation fluid sampling	**Pressure logging**	Wellhead and downhole
	Soil monitoring	Not performed	**Thermal logging**	Wellhead and downhole
	Atmospheric monitoring	Site based air monitor	**Wireline logging**	Timelapse Sonic, neutron, induction, gamma ray
	Ecological monitoring	Not performed	**Observation well**	3 dedicated wells
	Tracer analysis	Not performed	**Geochemical research/Fluid sampling**	Fluid sampling from reservoir (timelapse)
	Electromagnetic	Not performed	**InSAR**	Not performed
RESERVOIR STUDIES	**Reservoir modelling**	GEM-GHG and TOUGH2	**Geologic model**	PETREL
	Coring	4 wells drilled and 2 wells cored	**Seismic**	Surface and downhole
	Other technologies	Not performed		

Project context

The small scale CO_2 injection field test involved the injection of 10,400 tonnes of CO_2 into a deep saline aquifer in the South Nagaoka gas field, Nagaoka, Japan.

The project was conducted by Research Institute of Innovative Technology for the Earth (RITE) in co-operation with Engineering Advancement Association of Japan (ENAA). It was part of a wider project named the 'Research and Development of Underground storage for Carbon Dioxide', which was funded by theJapanese government as part of an R&D program for the fixation and utilisation of emitted CO_2.

Aims of the project

The aim of this project was to examine the feasibility of geological CO_2 sequestration in Japan, including public acceptance as well as environmental impact assessment methodology.

Ownership and liability

The project is owned by Research Institute of Innovative Technology for the Earth (RITE).

The injection site is located at Iwanohara base owned by INPEX Corporation in South Nagaoka gas field.

Regulatory and Approval Conditions

The project was permitted based on existing Mine Safety Act and High Pressure Gas Safety Act.

Pre injection geological database and site characterisation

The target reservoir was a sandstone bed of the Pleistocene-aged Haizume Formation, which lies about 1100 m deep and has a thickness of 60 m.

The upper portion of the Haizume Formation was selected for injection because it was found to have higher porosity and permeability than the deeper sandstones and was overlayed by a mudstone facies of the same formation with a thickness from 130 to 150 m. This mudstone has good sealing properties, which were confirmed during logging activities.

There were three dedicated observation wells where sampling of formation fluids, geophysical logging, pressure and temperature and cross-well seismic tomography were conducted.

The project included a simulation study for the prediction of time-lapse movement of injected CO_2 run prior to injection.

Other studies conducted as part of developing baseline data included cross-well seismic tomography, geophysical logging, pressure and temperature measurement and induced seismicity monitoring. Once the baselines were established the measurements were repeated constantly or intermittently throughout injections and post injections. The results were fed back into the simulation study to revise prediction of CO_2 movement (Kikuta, et al., 2004).

Source of CO_2

The CO_2 was purchased from a commercial source in liquid state.

Transport of CO_2

The Liquid CO_2 was delivered to the site by truck and transferred into a holding tank on site.

Additional project details

Injection of CO_2 at the Nagaoka test site began in July 2003 at 20tonnes/day, increasing to 40 tonnes/day in 2004. There were no problems experienced during injection and injection was only suspended three times in the injection phase due to periodic inspection of the CO_2 supply plant by supplier, and during the Mid-Niigata Chuetsu Earthquake.

The Mid-Niigata Chuetsu Earthquake provided a unique opportunity to examine the effects and identify impacts on geological storage of CO_2. The study compared the reservoir status before and after the earthquake through geophysical logging and seismic wave tomography; evaluation of well bottom pressures measured at the time of the earthquake; check of well conditions by cement bond sonic logging and a borehole televiewer; and inspection and air tightness/pressure test of the injection facility. The intactness of the aquifer was confirmed and measurements and analysis by seismic tomography confirmed that CO_2 was stored within the predicted range. The conditions of the wells, the reservoir, and the facility were found intact even after the earthquake, and the injection resumed at 40tonnes/day. The injection site was attacked by another intensive earthquake, Niigataken Chuetsu-oki Earthquake, in 2007. After the event, site integrity was confirmed again.

Stakeholder engagement

The site owner, INPEX, took the initiative in public outreach activities, building on their good relationship with local governments and communities.

As a part of the pilot, system studies were conducted on modelling and public outreach. It was reported that the project was to conduct an investigation on political and technical trends of CCS (including overseas) and a framework for public outreach of CCS was to be prepared. Project documents also indicated an investigation of implementation was to be carried out in terms of operating scheme, legal framework, regulations, overseas business potentials and public outreach (RITE, 2007).

Risk assessment process

Safety and risk analysis was carried out as part of this project and development of a guideline of safety assessment and environmental assessment was prepared.

Expertise compiled through the project contributed to “For safe operation of a CCS demonstration project”, a guideline for demonstrations in Japan released by the Ministry of Economy, Trade and Industry (METI).

Significant learnings from the project

- The feasibility of CO_2 injection was demonstrated in Japan by the successful injection into an aquifer with relatively low permeability.
- An understanding of CO_2 geological storage was significantly advanced by the surveys and test for ascertaining reservoir behaviour, as well as the monitoring and simulation study during and after CO_2 injection.
- Applicability of existing technologies, in fields such as natural resources engineering, was demonstrated through a range of processes including excavation of wells, design and construction of an injection facility, injection, monitoring and simulation studies.
- It was confirmed with various surveys that the storage site was not damaged by the two M6.8 earthquakes in 2004 and in 2007

PROJECT SUMMARY

Project name:
PCOR Lignite

Project lead organisation:
Plains CO_2 Reduction Partnership (PCOR)

Project type:
Enhanced Coalbed Methane

Project scale:
Small scale (<100,000 t)

Type and depth of reservoir:
Lignite coal, 365 meters

Total cost of project:
US$ 6,603,581

Location:
Burke County, ND, USA

Year of first injection:
2009

Current status:
Injection complete

Type of Seal:
Continuous layer of clay

PROJECT DETAILS

	Project operator	UND-EERC	**Project contact phone**	(701) 777-5279
	Project contact	Edward Steadman	**Project contact email**	esteadman@undeerc.org
	Project location	Burke County, ND, USA	**CO_2 source**	Commercial
	Injection site coordinates	48.8183° N, 102.5138° W	**CO_2 transport/delivery**	Rail/truck
	Project planning start	2005	**Injection rate**	6.5 tons/day
	Duration of injection	16 days	**Injection pressure**	720 psig
	Planned injection volume	Not known	**Total volume injected**	90 tonnes
	Reservoir porosity	1.8% (6.1% after drying)	**Reservoir permeability**	0.005-5mD
MONITORING	**Seismic monitoring**	Crosswell, passive	**Gravity studies**	Not performed
	Water monitoring	Shallow groundwater monitoring	**Pressure logging**	Wellhead and downhole
	Soil monitoring	Not performed	**Thermal logging**	Wellhead and downhole
	Atmospheric monitoring	Not performed	**Wireline logging**	Cased hole logging (Salinity, sonic, saturation)
	Ecological monitoring	Wetland monitoring	**Observation well**	5 wells drilled for injection and monitoring
	Tracer analysis	Introduced and natural, pulsed neutron	**Geochemical research/ Fluid sampling**	CO_2, HCO_3, CO_3, major ions, trace elements, salinity
	Electromagnetic	Not performed	**InSAR**	Not performed
RESERVOIR STUDIES	**Reservoir modelling**	ECLIPSE	**Geologic model**	Petrel
	Coring	injection well cored	**Seismic**	Not known
	Other technologies	Tilt meter array, Schlumberger Platform Express logging suite: gamma ray, sonic (pore pressure prediction, density determination, rock elastic constants estimation, bulk compressibility estimation), resistivity, density, multiarm calliper, natural radiation(sand/shale), acoustical.		

Project context

The PCOR Lignite project was a small scale test which injected 90 tonnes of CO_2 into a 3m coal seam in Burke County North Dakota. The aim of the test was to demonstrate the feasibility of simultaneous sequestration and natural gas production from a lignite coal seam.

The project was run by the Plains CO_2 Reduction Partnership, part of the US Department of Energy Regional Carbon Sequestration Partnerships (RCSP) initiative and as such has been part of the broader three phase implementation program. As a Validation scale pilot project, the project forms part of Phase II of the RCSP program.

The project was one of four validation scale pilot projects run by PCOR and the only one injecting CO_2 into an unminable coal seam. The project followed on from a Phase I project that was a reconnaissance-level characterisation study, which indicated the low ranking coal (such as the lignite seam) in the region may have multi-billion ton storage capacity for CO_2. Other results from Phase I indicated there may also be an opportunity for methane production.

Aims of the project

The PCOR lignite project based in Burke County, North Dakota, aims to evaluate CO_2 sequestration capacity and CH_4 production potential of North Dakota lignite resources. The project has three goals associated with the aim; to 1) ensure that the CO_2 can be safely injected and permanently trapped in lignite by means of adsorption (physical attachment), 2) assess the feasibility and economics of CO_2-enhanced methane production from lignite, and 3) develop protocols for similar operations in other coal seams in the region.

Ownership and liability

The project was owned and operated by the University of North Dakota-EERC, through its PCOR Partnership. The availability of mineral rights was a consideration in site selection. Activities were closely coordinated with NDIC OGD and the North Dakota State Land Department (NDSLD) to develop a list of candidate locations that would be appropriate for CO_2 injection and ECBM production. An area in Burke County in north-western North Dakota was identified as having geological characteristics that met the criteria for conducting a validation test to meet all of the primary goals of the project. Ultimately, the PCOR Partnership worked with NDSLD to obtain the mineral lease for Section 36, T159N, R90W in the southeast corner of Burke County for CO_2 injection and ECBM production. NDSLD granted permission for the proposed project.

Regulatory and Approval Conditions

A regulatory Permitting Action Plan was completed during planning stages of the project to provide a clear path. The demonstration test required the acquisition of several federal and state permits. The EERC completed an environmental questionnaire for the DOE. Based on the completed questionnaire, the field validation test was granted a categorical exclusion fulfilling federal permitting requirements. Under the State of North Dakota, the North Dakota Administrative Code (NDAC) contains the general rules and regulations adopted by the NDIC to conserve and govern the natural resources of the state. For the purposes of this field validation test, the following requirements were met:

- A well-spacing exception was granted due to the close proximity of the five research wells in a single 160-acre spacing unit.
- Drilling permits were granted for each well
- Sundry Notices were regularly completed and submitted to the NDIC for work performed on all the wells.
- An injection application was completed and granted for the intended injection well.
- An aquifer exemption request was needed because the intended injection zone met the criteria for a potential underground source of drinking water. The EERC demonstrated the injection zone would qualify as an exempted aquifer from analysis of data gathered during the drilling and development of the injection well.

Pre-injection geological database and site characterisation

Existing field data was used for preliminary modelling. Characterisation provided details of multiple coal seams with sufficient areal extent and low permeability clay layers above and below the target seam of the Fort Union Group of the North Dakota and Montana portions of the Williston Basin. The targeted coal seam (~365m depth) was selected as the best candidate for CO_2 injection.

The project used a five-spot well configuration which allowed for effective and efficient operation and monitoring of the water production and CO_2 injection program. Geophysical logging, drill cutting collection and description took place at all five wells. The injector well had additional logging and core was collected. Geophysical logging was conducted with express suite, sonic, wireline pulse neutron. Other formation logging activities included Multiarm calliper, acoustical and elemental capture spectroscopy. Petrel was used for the geological modelling based on information collected during well drilling, baseline studies and previous investigations as part of phase I.

Source of CO_2

Commercial CO_2 was purchased for the injection.

Transport of CO_2

The CO_2 was transported by truck from the supplier directly to the injection site.

Additional project details

The injection began in early 29 and at the same time the monitoring, mitigation and verification plan was implemented to monitor the movement of CO_2 through the coal seam. The project demonstrated that North Dakota has suitable land area, overburden depths and coal thickness to accommodate further CO_2 storage in the lignite coals. This was the first field study to be completed, determining the ability of lignite coal seams to store CO_2.

Stakeholder engagement

An outreach action plan was prepared as part of the projects planning program. The project plan was assisted by the PCOR partnerships development of resources for public education and information to be utilised by the validation project teams. These outreach resources included:

- A variety of PowerPoint presentations.
- Display booth and materials.
- Public website and members only website
- Knowledge in brief—fact sheets on key topics and validation projects.
- Knowledge in-depth—over 50 scientific and technical reports.
- Five documentaries available on DVD—co-productions of Prairie Public Broadcasting (PPB) and the PCOR Partnership.
- Proceedings from the annual PCOR Partnership meetings and access to other meeting materials.
- A 65-page regional atlas.

Risk assessment process

A formal risk assessment was not conducted at the beginning of this project because of its small scale, and the overall nature of the project. However, all aspects of the project were conducted to industry standards.

Significant learnings from the project (PCOR Factsheet for field validation, 2009)

The study provides evidence that lignite coal may be a viable target for storing CO_2. Results at this field validation test indicate that CO_2 can be maintained within expected intervals and appears to adsorb to the lignite coal.

Various injection rates and conditions were tested. Generally, the highest flow rates were achieved at the highest injection pressures. Changing conditions to lower density and viscosity downhole were not successful at producing increased injection rates. Heating the CO_2 at the surface and injection at maximum permitted pressures are recommended. Downhole pressure and pH were the most significant indicators for the presence of CO_2.

Economic development costs to drill and complete may be able to be reduced by greater than 50% if additional work is performed to increase injection rates such as horizontal drilling, fracture treatment, and dewatering. Low permeability, lack of continuity, and the potential for wellbore damage present challenges to CO_2 injection into lignite.

PROJECT SUMMARY

Project name:
PCOR Williston Basin – Phase II

Project organisation:
Plains CO_2 Reduction Partnership

Project type:
Enhanced Oil Recovery

Project scale:
Small scale (400 t injected)

Type and depth of reservoir:
Limestone, 2450m

Total cost of project:
US$ 4.3 Million

Location:
NW McGregor Field, North Dakota, USA

Year of first injection:
2009

Current status:
Injection complete

Type of Seal:
Tight carbonates and anhydrites

PROJECT DETAILS

	Project operator	Eagle Operating Inc	**Project contact phone**	(701) 777-5279
	Project contact	Edward Steadman	**Project contact email**	esteadman@undeerc.org
	Project location	Williams County, North Dakota, USA	**CO_2 source**	Commercial
	Injection site coordinates	47°28'00"N, 103°29'40"W	**CO_2 transport/delivery**	Truck
	Project planning start	2007	**Injection rate**	313 tpd
	Duration of injection	36 hours	**Injection pressure**	3000 psi
	Planned injection volume	1,300,000 t/yr	**Total volume injected**	400 tonnes
	Reservoir porosity	15%	**Reservoir permeability**	0.35mD matrix and fractures
MONITORING	**Seismic monitoring**	VSP, RST (reservoir saturation tool)	**Gravity studies**	Not known
	Water monitoring	Shallow wells	**Pressure logging**	Wellhead and downhole
	Soil monitoring	Not known	**Thermal logging**	Wellhead and downhole
	Atmospheric monitoring	Not known	**Wireline logging**	Pulsed Neutron
	Ecological monitoring	Not known	**Observation well**	Alternative production well used
	Tracer analysis	Introduced tracers, PFC	**Geochemical research/ Fluid sampling**	CO2, HCO3, CO3-2, Major ions, trace elements, salinity, hydrocarbon composition
	Electromagnetic	Not known	**InSAR**	Not known
RESERVOIR STUDIES	**Reservoir modelling**	History matching	**Geologic model**	Developed
	Coring	Existing	**Seismic**	Not known
	Other technologies	GEM-GHG		

Project context

The PCOR Williston Basin project was a small scale project injecting CO_2 into a deep carbonate formation in the Northwest McGregor oil field of North Dakota using a huff'n'puff (HnP) approach. The project, which was carried out in partnership with the field operators - the *Eagle Operating Company*, was run by the Plains CO_2 Reduction Partnership (PCOR), part of the US Department of Energy Regional Carbon Sequestration Partnerships (RCSP) initiative and as such has been part of the broader three-phase implementation program.

As a validation scale pilot, the project forms part of Phase II of the RCSP program. It was one of four validation phase (Phase II) pilot projects run by PCOR providing a field validation test exploring enhanced oil recovery (EOR) in a saline formation using 'huff n puff' (HnP) technique. The project followed on from a Phase I project, which was a reconnaissance-level characterisation study. There were plans to continue development of this project to a Phase III - development phase with plans to inject 500,000 – 1,000,000 tonnes of CO_2; however, this has subsequently been dropped.

Aims of the project

The main aim of the PCOR Williston Basin Project is to evaluate the potential dual purpose of CO_2 sequestration and EOR in carbonate rocks deeper than 2438 meters. The project goals included to 1) determine the baseline geological characteristics of the injection site and surrounding areas, 2) inject CO_2 into the target oil reservoir using a HnP approach, and 3) evaluate the effect that injected CO_2 has on the ability of the oil reservoir to sequester CO_2 and produce incremental oil.

Ownership and liability

The project was owned by PCOR and operated by University of North Dakota's Energy and Environmental Research Center. The well to be used as an injector well, along with a nearby well producing from the same reservoir - which was to be used as an observation well, are located in the Northwest McGregor Oilfield owned by *Eagle Operating Inc*,.

Regulatory and Approval Conditions

A regulatory permitting action plan was completed during planning stages of the project to provide a clear path. The North Dakota Industrial Commission – Oil and Gas Division required the submission of a Sundry Notice for injection into an existing oil well.

Pre-injection geological database and site characterisation

The injection site was located on the northern tip of the Nesson Anticline, which is near the depocenter of the Williston Basin. The primary source of oil production in the area is from Mississippian Mission Canyon Formation.

The Mission Canyon Formation is a carbonate-dominated formation that includes interbeds of anhydrite and salt. It was deposited in a mid-energy depositional setting ending with a sabkha environment and represents a major regressive sequence.

The target reservoir is primarily limestone, while the seal consists of tight carbonates and anhydrites. Secondary seals, such as the Last Salt Formation, serve as major seals and would prevent vertical migration of CO_2. The project characterisation included fluid sampling and analysis for key geochemical parameters as well as CO_2, CH_4, and tracer contents from the existing injector and observation wells, and ground water samples from shallow wells in the area. Analysis of fracture data was conducted to predict fracture distribution and the effect of fracture networks on the injection and the fate of CO_2.

Static petrophysical modelling was conducted and used as a basis for dynamic injection modelling. VSP and RST results provided the key baseline project information to be compared against post injection measurements to observe the CO_2 plume.

Source of CO_2

CO_2 was purchased from a commercial source, Praxair.

Transport of CO_2

Praxair transported the CO_2 to the injection site via train and truck and conducted the injection into the target reservoir.

Additional project details

440 tonnes of CO_2 was injected into a single well during the test. This was allowed to "soak" for 2 weeks, after which the well was put back into oil production.

The Williston Basin Project was unique for the following reasons:

- The reservoir had not been tested for EOR operations,
- It was among the deepest at a depth of 2450m,
- The pressure (approximately 20MPa) and temperature (approximately 80 °C) was among the highest for a HnP project, and
- Other HnP projects are in clastic reservoirs, while the Williston Basin Project injection targets a carbonate reservoir.

Stakeholder engagement

An outreach action plan was prepared as part of the projects planning program. The project plan was assisted by the PCOR partnerships development of resources for public education and information to be utilised by the validation project teams. These outreach resources included:

- A variety of PowerPoint presentations.
- Display booth and materials.
- Public website and members-only website.
- Knowledge in brief - fact sheets on key topics and validation projects.
- Knowledge in-depth - over 50 scientific and technical reports.
- Five documentaries available on DVD - co-productions of Prairie Public Broadcasting (PPB) and the PCOR Partnership.
- Proceedings from the annual PCOR Partnership meetings and access to other meeting materials.
- A 65-page regional atlas.

Risk assessment process

Not known.

Significant learnings from the project

- RST and VSP were shown to be effective tools for determining the fate of the CO_2 in a carbonate formation deeper than 8000 ft (2438 m).
- Results suggest CO_2 H&P is a viable approach to improved oil recovery in older Williston Basin wells.
- Predictions of the CO_2 fate and incremental oil production were confirmed by the actual observed response of the reservoir.
- The use of CO_2 for H&P on individual wells in the region may yield further economically attractive opportunities, providing additional incentive to the creation of a CO_2 distribution infrastructure.

PROJECT SUMMARY

Project name:
PCOR Zama Field Validation Project

Project organisation:
Plains CO_2 Reduction Partnership (PCOR)

Project type:
Enhanced Oil Recovery

Project scale:
Approximately 40,000 tons

Type and depth of reservoir:
Devonian Carbonate Pinnacle Reef, 1600m

Total cost of project:
$US 7,613,203

Location:
Zama City, Northwestern Alberta, Canada

Year of first injection:
2006

Current status:
Injection continuing beyond 2009 Phase

Type of Seal:
Shale

PROJECT DETAILS

	Project operator	Apache Canada Ltd	**Project contact phone**	(701) 777-5279
	Project contact	Edward Steadman	**Project contact email**	esteadman@undeerc.org
	Project location	Alberta	**CO_2 source**	Natural gas sweetening from Zama gas plant
	Injection site coordinates	59°3'59" N 118°47'7" W (TBC)	**CO_2 transport/delivery**	Not known
	Project planning start	2005	**Injection rate**	20 - 80 tpd
	Duration of injection	4 years	**Injection pressure**	Not known
	Planned injection volume	> 40,000 tonnes	**Total volume injected**	Approx 30,000 tons CO_2 to end 2009
	Reservoir porosity	10%	**Reservoir permeability**	100 – 1000 mD
MONITORING	**Seismic monitoring**	Not known	**Gravity studies**	Not known
	Water monitoring	From monitoring wells	**Pressure logging**	Twice yearly
	Soil monitoring	Not known	**Thermal logging**	Not know
	Atmospheric monitoring	Not known	**Wireline logging**	Yes for dynamic elastic properties and stress
	Ecological monitoring	Not known	**Observation well**	Yes
	Tracer analysis	PFC	**Geochemical research/Fluid sampling**	Wellhead and formation fluid sampling
	Electromagnetic	Not known	**InSAR**	Not known
RESERVOIR STUDIES	**Reservoir modelling**	Yes – petrophysical, geomechanical and geochemical modelling	**Geologic model**	Not known
	Coring	Yes	**Seismic**	Not known
	Other technologies			

Project context

The Zama Field Validation Project is one of the Plains CO_2 Reduction Partnership (PCOR) validation projects. It was the first geological sequestration projects to occur under the USDOE's Regional Carbon Sequestration Partnerships. The Project operates in northwestern Alberta, Canada.

This project was eventually continued beyond the expected end date of 2009, but as it was set up as a field validation test the project to 2009 has been included in this study of small scale project.

Aims of the project

From the prospective of the PCOR Partnership, the aim was to create a best practice manual for monitoring, verification and accounting operations at an oil production site using acid gas. The project aims to determine the effects of acid gas (80% CO_2) injection for acid gas disposal, CO_2 storage and enhanced oil recovery. Storage of acid gas will also eliminate the accumulation of elemental sulphur on the surface.

Ownership and liability

Through the PCOR, the Energy and Environmental Research Centre (EERC) worked in partnership with Apache Canada Ltd. Other partners include Natural Resources Canada, The Alberta Energy and Utilities Board and Alberta Geological Survey.

Regulatory and approval conditions

National Environmental Policy Act compliance. Regulatory Permitting Action Plan completed 2006.

Pre-injection geological database and site characterisation

PVT samples in October 1967, core analysis in 1968.

Petrophysical modelling was carried out by the University of Regina in 2005. Geomechanical and geochemical models were also created.

Source of CO_2

The acid gas stream comprising on average 80% CO_2 and 20% H_2S (Note some sources give the composition as 70% CO_2) is produced at Apache Canada Limited's Zama gas plant.

Transport of CO_2

Not known

Additional project details

The project injected approximately 50 tons of CO_2 per day (20-90 tpd) sequestering CO_2 at 12-15 kt/year. Existing wells were recompleted before injection

The injection zone is monitored to ensure protection of groundwater resources.

By August 2009 more than 25,000 barrels of oil were recovered as a result of the CO_2 injection.

The project was continued by Apache Canada Ltd beyond the expected end in 2009 and injection is continuing in a new phase of the project with plans for more than a million tons to be injected.

The EERC is conducting the MMV program and will test and refine the protocols for MMV procedures in CO_2 and acid gas sequestration projects.

New core that has been exposed to acid gas was collected and analysed for mineralogic changes.

Stakeholder engagement

Outreach action plan completed 2006

Risk assessment process

Not known

Significant learnings from the project

Not known

PROJECT SUMMARY

Project name: Penn West Energy EOR Project	**Total cost of project:** US$ 34,400,000
Project organisation: PennWest Energy (now PennWest Exploration)	**Location:** Alberta, Canada
Project type: Enhanced Oil Recovery	**Year of first injection:** 2005
Project scale: Small scale (105,694 t (Gross))	**Current status:** Pilot terminated 2010, area on waterflood
Type and depth of reservoir: Sandstone, 1650 meters	**Type of Seal:** Shales

PROJECT DETAILS

	Project operator	Penn West Petroleum Ltd.	**Project contact phone**	(403) 777-2500
	Project contact	(EOR Consultant) Ian Bryden	**Project contact email**	ian.bryden@pennwest.com
	Project location	Alberta, Canada	**CO_2 source**	Gas Processing
	Injection site coordinates	53°55'41"N, 115°36'11"W	**CO_2 transport/delivery**	Truck
	Project planning start	2003	**Injection rate**	50 tonnes/day
	Duration of injection	5 years	**Injection pressure**	13-14 MPa
	Planned injection volume	Not known	**Total volume injected**	105,964 (Gross), 56,749 (Net)
	Reservoir porosity	8-16%	**Reservoir permeability**	2-31mD
MONITORING	**Seismic monitoring**	2D & 3D surface, 2D-VSP, timelapse	**Gravity studies**	Not performed
	Water monitoring	3 dedicated shallow wells (30-50m)	**Pressure logging**	In observation well
	Soil monitoring	9 dedicated shallow wells (<22m)	**Thermal logging**	In observation well
	Atmospheric monitoring	Tuneable laser diodes	**Wireline logging**	Not performed
	Ecological monitoring	Not known	**Observation well**	New drill dedicated 1650m
	Tracer analysis	No tracers used. Flood progress was monitored by changes in water chemistry and CO_2 content of produced gas.	**Geochemical research/ Fluid sampling**	From observation well (2 points), from existing producers (8 wells)
	Electromagnetic	Not performed	**InSAR**	Not performed
RESERVOIR STUDIES	**Reservoir modelling**	ECLIPSE	**Geologic model**	Yes
	Coring	100 cored wells	**Seismic**	Commercial Characterisation
	Other Technologies	Not known		

Project context

Also known as the Pembina Cardium Project, the Pennwest Pilot Project is an enhanced oil recovery (EOR) project located in the Pembina oilfield in Alberta, Canada. The project was one of four CO_2 EOR projects approved to receive a royalty credit under the Alberta Government's CO2-EOR Royalty Program.

In 2004, after a detailed review of the potential for CO_2 monitoring of storage within the Upper Cretaceous Cardium Formation of the Pembina Field, the project was also chosen as a CO_2 monitoring pilot.

Injection under the project commenced in 2005 and was terminated in 2010.

Aims of the project

The Pennwest Energy Pilot project aimed to test if injecting liquid CO2 was an economically viable oil recovery strategy to maximise oil recovery.

The monitoring project aimed to (1) map and assess the condition of the existing wells and the geology and hydrogeology at the regional, local, and site scales with a view to defining potential leakage paths and the capacity of the Cardium reservoir to store CO_2, and (2) monitor the movement of CO_2 in the Cardium reservoir using seismic, pressure, temperature, and produced-fluid signatures both within and external to the Cardium reservoir.

Ownership and liability

The project is owned and operated by *PennWest Energy*. The injection facilities are owned and operated by *PennWest Petroleum Ltd.*

Researchers and research contractors were required to maintain Comprehensive General Liability Insurance; Penn West retained responsibility for all well operations.

Regulatory and approval conditions

Alberta ERCB Directive 51 regarding injection well completion and testing requirements; Enhanced Oil Recovery Approval including voidage replacement, minimum reservoir pressure, minimum miscible fluid volume, specified miscible fluid and production fluid sampling and analysis, well pressure measurements and details of annual reporting requirements.

Pre injection geological database and site characterisation

This project is extensively documented. The Pembina field is one of the most areally extensive conventional fields in North America and represents the single largest conventional hydrocarbon reservoir in Alberta, with oil and gas production ranging from shallow Cretaceous reservoirs to deep Upper Devonian reefs. The geology of the Cardium reservoir in the field, which was discovered 1953, has been well established by its exploration and production history. The EOR project utilised the geological model developed by Penn West using *Petrel* and this was incorporated into the *Eclipse 100* Black oil simulator for history matching. Geochemical modelling utilising *Solmineq* and *Gamspath* was also undertaken.

The target injection zones are three sandstone units, 3 m thick with intervening shale units, 1 m thick between the upper and middle sandstone units and 5 m thick between the middle and lower sandstones. The average core porosity and permeability range from 8% and 31 md in the conglomerate to 16% and 21 md in the middle and upper sandstone units, while the lower sandstone unit has 10 md permeability, half that of the upper and middle sandstone units. The reservoir temperature is 50°C and the pressure of the water-flooded reservoir was approximately 19 MPa, similar to the original reservoir pressure of 18 to 19 MPa. The EOR pilot consisted of two CO_2 injectors and six producers which perforated all four units (conglomerate, upper sandstone, middle sandstone, and lower sandstone) in the 20 m thick Cardium Formation.

Source of CO_2

The CO_2 was sourced from Ferus Gas Industries, who own three gas processing facilities.

Transport of CO_2

The CO_2 was transported from the capture facility to the injections wells by truck.

Additional project details

The project injected predominantly into two vertical wells during 2005-2007 and two horizontal wells during 2008-2010. The vertical injections were intended for the project team to gain practical experience in operating a CO_2 flood for EOR purposes. The program did not yield the desired results, which was to yield production profile required for economically viable injection. It was from here that the horizontal injection patterns were developed in 2007 as an expansion of the vertical injection program. Two single-leg horizontal production wells (with horizontal length of 1000m) were drilled and existing vertical wells were converted to CO_2 and water injection.

Stakeholder engagement

The project included outreach activities through media releases, stakeholder updates available on the internet and subscriber e-mails.

Stakeholder and public engagement was viewed as a critical component of the project. The project was conducted within a producing oil field and local residents tended to view it as "business as usual".

Risk assessment process

The pilot was conducted to test the production rate performance and incremental oil recovery. As an addendum to the pilot, and in planning for a commercial CO2 EOR scheme, Penn West conducted a comprehensive risk identification, quantification (as to occurrence, severity and consequences) and identification of risk management options. This occurred towards the end of the project.

Significant learnings from the project

- Monitoring, Measurement and Verification (MMV) has allowed for significant advances in design and deployment of an observation well, design of a well-cement sampling system, design and deployment of an environmental monitoring system, use of Vertical Seismic Profiling (VSP), and the development of in-situ tracers during the pilot project.
- Existing pre-pilot and pilot data were successfully history matched with the Eclipse compositional model (E-300). However, scenarios of future conditions of the oil production for CO2-EOR appeared anomalous. These results need to be verified using a different reservoir simulator, such as the GEM compositional reservoir model of the Computer Modelling Group (Monitoring Summary Report).
- Directional permeability was found to be a more significant factor than had been anticipated.

There were no new or unanticipated learnings relative to gas handling, flowline leaks or injectivity. Managing corrosion was easier than anticipated. Public outreach was less of an issue than expected. Risk management was a productive exercise from both a technical and managerial perspective.

PROJECT SUMMARY

Project name:
Recopol Project

Project organisation:
RECOPOL Consortium and coordinated by TNO-NITG

Project type:
Enhanced Coalbed Methane

Project scale
Small scale

Type and depth of reservoir:
Coal, 1050-1090 meters

Total cost of project:
Not known

Location:
Katowice, Poland

Year of first injection:
2004

Current status:
Injection complete

Type of Seal:
Miocene shale

PROJECT DETAILS

	Project operator	Central Mining Institute (+48 (0)32 324 6606, kdxpk@gig.katowice.pl	**Project contact phone**	+31 (0)30 256 4606
	Project contact	Current contact not known, previously Henk Pagnier at TNO	**Project contact email**	Not known
	Project location	Katowice, Poland	**CO_2 source**	Industrial sources
	Injection site coordinates	50°15′N, 19°0′E	**CO_2 transport/delivery**	Trucks
	Project planning start	November 2001	**Injection rate**	12-15 tonnes/day
	Duration of injection	June-November 2004	**Injection pressure**	Not known
	Planned injection volume	760 tonnes	**Total volume injected**	760 tonnes
	Reservoir porosity	0.5%	**Reservoir permeability**	0.5-5 mD
MONITORING	**Seismic monitoring**	Crosswell tomography	**Gravity studies**	Not performed
	Water monitoring	Not performed	**Pressure logging**	Wellhead and downhole
	Soil monitoring	Dedicated shallow wells (2m)	**Thermal logging**	Wellhead and downhole
	Atmospheric monitoring	Not performed	**Wireline logging**	Not performed
	Ecological monitoring	Not known	**Observation well**	Existing producers
	Tracer analysis	dC13	**Geochemical research/Fluid sampling**	Produced gas/water analysis
	Electromagnetic	Not performed	**InSAR**	Not performed
RESERVOIR STUDIES	**Reservoir modelling**	MoRes, SIMED, COMET1	**Geologic model**	Project created (petrel)
	Coring	From one well	**Seismic**	Not known
	Other technologies	Not known		

Project context

The aim of the RECOPOL project was to demonstrate the feasibility of CO_2 injection into a coal under conditions encountered in Europe and that storage of CO_2 in coal beds was a safe and viable option. This project was the first ECBM test in Europe and was located in the village of Kaniow in Upper Silesian Basin .Poland. The project was the first pilot project to attempt injection and production in different wells (Sian, 2007). The project was a European Commission funded project, carried out by the International consortium lead by Netherlands Organization for Applied Scientific Research – Netherlands Geological Survey (TNO-NITG).

RECOPOL stands for "Reduction of CO_2 emission by means of CO_2 storage in coal seams in the Silesian Coal Basin of Poland".

Aims of the project

The project's main objective was to evaluate if enhanced coalbed methane (ECBM) production could be used to reduce greenhouse gas emissions and was a safe and viable option for long term storage of CO_2. The main task within the project was the development, in Poland, of an actual field site where this process could be demonstrated.

Ownership and liability

Metanel Joint-stock Company owns the exploration concession for coalbed methane (CBM) entitling them to exploitation of coalbed methane in the mining area of the Silesia Colliery, within which the injection site is located. However, the injection site itself is located where a gravel mining site was planned. A lease contract was arranged with the landowner for the injection site.

The liability arrangements are not known.

Regulatory and approval conditions

Being solely a research project, the project has benefited from the support from the funding organisation as well as the arrangements with

Pre-injection geological database and site characterisation

The Silesian Basin area of Poland was selected as the injection site due to the favourable physical properties of the coal seams. The injection site is located in the village of Kaniow, 40km south of Kantowice, Poland, within the concession of the Selesia Mine. The site has a history of actively producing coal bed methane (CBM) and from this the project was able to access historical data to be used as a baseline against experimental results. Historical data indicated intra-formational faults of the coal seams have sealing characteristics. The carboniferous deposits are discordantly covered by 200 meter thick Miocene Shales. A new injection well was drilled and an existing well was cleaned up, repaired and put back into production. Baseline cross-well seismic surveys were conducted and eleven well were used to construct a 3D geologic model in PETREL.

Source of CO_2

The CO_2 was obtained from industrial sources.

Transport of CO_2

The CO_2 was trucked to the injection site and stored in liquid form (at a temperature of -20 º C) in two storage tanks.

Additional project details

The principal targets for CO_2injection are coal seams of Carboniferous age that are between 1 and 3 m thick and are between 900-1100 m deep. Several actions were taken to establish continuous injection, which was eventually reached in April 2005, following fraccing of the coal seams. The permeability of the coal seams reduced over time, presumably due to swelling as the result of contact with the CO_2. Following fraccing continuous injection rates reached levels of 12-15 tonnes/day until supplies of CO_2 were exhausted at the scheduled end of the project in June 2005.

Stakeholder engagement

During the course of the project the RECOPOL parteners conducted extensive outreach activities. As part of the project's final dissemination activities, a workshop was organised by TNO-NIGT, the project co-ordinators, which was held in the town of Szczyrk in Southern Poleland. The workshop looked at the opportunities for carbon capture and storage in Central and Eastern Europe with specific focus on the results of the project.

Risk assessment process

Not known.

Significant learnings from the project

- The project did prove methane production is enhanced following CO_2 injection however, the processes underlying this are not fully understood, in particular the effect of $CO2_2$ absorption on coal swelling and reduction in permeability around the injection well.
- Results of the project demonstrate that lower permeability coals can achieve satisfactory results following fraccing stimulation activities.
- The remaining uncertainties leave project conclusions questioning the technically feasible geological storage option of CO_2-ECBM, although the projects results were encouraging.

PROJECT SUMMARY

Project name:
SECARB Black Warrior Basin Coal Seam Project – Phase II

Project organisation:
SECARB (Southeast Regional Carbon Sequestration Partnership)

Project type:
Enhanced Coalbed Methane

Project scale:
Small scale (278 t)

Type and depth of reservoir:
Coal seams, 287-549 meters

Total cost of project:
US$ 2,381,440

Location:
Tuscaloosa County, Alabama, USA

Year of first injection:
2010

Current status:
Injection complete

Type of Seal:
Marine shale units

PROJECT DETAILS

	Project operator	Geological survey of Alabama	**Project contact phone**	(205) 349-2852
	Project contact	(field test site) Jack Pashin	**Project contact email**	jpashin@gsa.state.al.us
	Project location	Blue Creek Field, Tuscaloosa County, AL USA	**CO_2 source**	Geologic source (Jackson Dome)
	Injection site coordinates	33°28′37″N 87°29′39″W	**CO_2 transport/delivery**	Truck
	Project planning start	2005	**Injection rate**	25-200 tons/day
	Duration of injection	7 12-hour injection events	**Injection pressure**	544-1025 psi
	Planned injection volume	1000 tons	**Total volume injected**	278 tonnes
	Reservoir porosity	< 1 percent	**Reservoir permeability**	1 mD to 40 mD
MONITORING	**Seismic monitoring**	Not performed	**Gravity studies**	Not performed
	Water monitoring	Dedicated shallow wells	**Pressure logging**	Wellhead and downhole
	Soil monitoring	Soil flux	**Thermal logging**	Wellhead and downhole
	Atmospheric monitoring	Not performed	**Wireline logging**	Caliper, gamma-ray, and bulk density in monitor wells plus existing gamma-density logs for injection well.
	Ecological monitoring	Not performed	**Observation well**	4 dedicated wells
	Tracer analysis	Isotopic	**Geochemical research/Fluid sampling**	Sampled from 4 wells
	Electromagnetic	Not performed	**InSAR**	Not performed
RESERVOIR STUDIES	**Reservoir modelling**	COMET3	**Geologic model**	Performed
	Coring	Coal zones cored in all four observation wells	**Seismic**	Not performed
	Other technologies	Not known		

Project context

The Southeast Regional Carbon Sequestration Partnership (SECARB) is one of seven partnerships across USA formed as part of the US Department of Energy Regional Carbon Sequestration Partnerships (RCSP) initiative which involved a three phase implementation program. The SECARB Black Warrior Basin Coal Seam project was part of the SECARB program in Phase II (Validation), one of four run by SECARB. The Black Warrior Basin Coal Seam project formed one of two Coal Seam field tests for SECARB.

Aims of the project

The principal objectives of the SECARB Black Warrior Basin Coal Seam Project were to determine if sequestration of carbon dioxide in mature coalbed methane reservoirs is a safe and effective method to mitigate greenhouse gas emissions; and if sufficient injectivity exists to efficiently drive CO2-enhanced coalbed methane recovery.

Ownership and liability

The project was owned by SECARB and operated by the Geological Survey of Alabama and the Southern States Energy Board. The test site was located on the Blue Creek coalbed gas field in Tuscaloosa County, Alabama. The Gas Field was owned and operated by El Paso Exploration and Production, Incorporated during the test and is now owned and operated by *Saga Petroleum LLC* of Colorado.

Regulatory and approval conditions

Class II Underground Injection Control permit issued by State Oil and Gas Board of Alabama.

Pre injection geological database and site characterisation

The Black Warrior Basin of Alabama has been an actively mined coalfield since the 19th century and has been actively exploited for coal bed methane since the 1980's. It therefore has an extensive geological database that predates this project.

Coalbed methane is produced from multiple thin coal seams (0.3 to 3.0 meters) distributed through more than 300 meters of section of the basin. The basin is broken by a number of northwest-trending normal faults forming horst, graben, and half-graben structures. Within the coalbed methane producing region, most of the normal faults are thin skinned and have displacements of 400 feet (122 m) or less. The main economic coals belonging to the upper Pottsville formation of Early Pennsylvanian age.

The field test was designed and conducted to test reservoir conditions in the three primary target coal zones*. El Paso Exploration and Production* provided access to the well to the SECARB team for CO_2 injection. Four wells were drilled to monitor reservoir pressure, gas composition, water quality, and the CO_2 plume. The targeted coal seams were in the Pratt (-286m), Mary Lee (426m), and Black Creek (-549m) Coal groups within the upper Pottsville Formation and range from 286 meters to 549 meters in depth and 0.3 meters to 2.0 meters in thickness.

Source of CO_2

The carbon dioxide was donated by Denbury Resources, Incorporated, and was obtained from the natural accumulations of the Jackson Dome.

Transport of CO_2

The carbon dioxide was delivered to the site by tanker trucks.

Additional project details

Technically feasible sequestration capacity in established fields is estimated conservatively to be 468 Million tonnes, and enhanced coalbed methane recovery potential is estimated to be between 0.8 and 1.6 trillion cubic feet. Two coal-fired power plants with combined CO_2 emissions exceeding 31 Million tonnes/year are located immediately north of the coalbed methane fields. The proximity of mature coalbed methane reservoirs to these plants provides substantial economic incentive for carbon capture and storage in the Tuscaloosa area. The numerous conventional hydrocarbon reservoirs and saline aquifers in the basin can help facilitate longer-term sequestration.

Stakeholder engagement

There were a number of outreach methods used during the project as part of a rigorous technology transfer and outreach program to inform and educate public and industry stakeholders. Engagement was conducted though technical and general publications with project information, local, regional and international meetings as well as running website posts with project updates.

Risk assessment process

Geologic and operational risks were assessed throughout the project, and mitigation strategies were developed offset known risks. On-site safety program was administered by El Paso Exploration and Production, Incorporated, and the project was conducted safely.

Significant learnings from the project

Results demonstrate that significant injectivity exists in Black Warrior coalbed methane reservoirs and that reservoir heterogeneity is a critical factor that must be considered when implementing CO2 sequestration and CO2-enhanced recovery programs. Permeability of target coal seams decreases with depth from 40 to 1 mD. Injection was conducted in strongly pressure-depleted reservoirs, and so injectivity was high in the target coal seams. Hydraulic fractures had a strong effect on plume geometry. Multi-zone monitoring demonstrated that the injected CO2 remained confined in the target coal seams.

PROJECT SUMMARY

Project name:
SECARB Central Appalachian Coal Seam Project

Project organisation:
Southeast Regional Carbon Sequestration Partnership (SECARB)

Project type:
Enhanced Coalbed Methane

Project scale:
Small scale (907 t)

Type and depth of reservoir:
Coal, 700 - 320 m

Total cost of project:
US$ 2,710,000

Location:
Russell County, Virginia, USA

Year of first injection:
2009

Current status:
Injection Complete

Type of Seal:
Hensley Shale

PROJECT DETAILS

	Project operator	SECARB	**Project contact phone**	(540) 231-5273
	Project contact	Michael Karmis	**Project contact email**	mkarmis@vt.edu
	Project location	Russell County, VA, USA	**CO_2 source**	Praxair
	Injection site coordinates	36.9260° N, 82.1173° W	**CO_2 transport/delivery**	Truck
	Project planning start	2005	**Injection rate**	37 tpd
	Duration of injection	30 days	**Injection pressure**	Between 660 and 1000 psia
	Planned injection volume	Not known	**Total volume injected**	907 tonnes
	Reservoir porosity	1%	**Reservoir permeability**	5-20 md
MONITORING	**Seismic monitoring**	Not performed	**Gravity studies**	Not performed
MONITORING	**Water monitoring**	Dedicated shallow wells, underground mines	**Pressure logging**	Wellhead and downhole
MONITORING	**Soil monitoring**	CO_2 and CH_4 soil flux	**Thermal logging**	Wellhead and downhole
MONITORING	**Atmospheric monitoring**	Not performed	**Wireline logging**	GR, calliper, density, induction, temperature, acoustic televiewer, spinner survey
MONITORING	**Ecological monitoring**	Pre- and post-injection vegetative stress	**Observation well**	2 dedicated wells
MONITORING	**Tracer analysis**	Positron emission tomography (PET) Perflurocarbon	**Geochemical research/Fluid sampling**	Composition analysis
MONITORING	**Electromagnetic**	Not performed	**InSAR**	Not performed
RESERVOIR STUDIES	**Reservoir modelling**	COMET3	**Geologic model**	Yes
RESERVOIR STUDIES	**Coring**	One well	**Seismic**	Not performed
RESERVOIR STUDIES	**Other technologies**	Not known		

Project context

Southeast Regional Carbon Sequestration Partnership (SECARB) is one of seven partnerships across USA formed as part of the US Department of Energy Regional Carbon Sequestration Partnerships (RCSP) initiative which involved a three phase implementation program. The SECARB Central Appalachian Coal Seam project was part of the SECARB program in Phase II (Validation), which was one of four projects managed by SECARB. The Central Appalachian Coal Seam project formed the first of two Coal Seam field tests for SECARB.

The regional study area of the project was located within the Central Appalachian Basin, a northeast- to southwest-trending basin encompassing approximately 25,900 square kilometres in southwestern Virginia and southern West Virginia.

Aims of the project

The Central Appalachian field validation test aimed to assess and to verify the sequestration capacity and performance of mature coalbed methane reservoirs in the Central Appalachian Basin by injection-falloff and production testing, as well as the implementation of subsurface monitoring programs.

Ownership and liability

The project was operated by the Virginia Center for Coal and Energy Research, and Virginia Tech. The mining lease was owned and operated (the production wells) by CNX Gas corporation.

Liability and indemnity fell under an agreement between CNX Gas Corporation, Buckhorn Coal Company and Marshall Miller and Associates.

Regulatory and approval conditions

EPA Class V UIC permit.

Pre-injection geological database and site characterisation

The coal seams utilised in the project formed parts of the Lee and Pocahontas Formations. The Lee formation is the shallowest formation while the Pocahontas Formations directly overlies the late Mississippian Bluestone Formation.

These coal seams form part of an extensively mined coalfield and CBM gas playand there is therefore much pre-existing data that was utilised by the project. A pre-existing CBM well was converted for CO2 injection and one core hole, and one monitoring wells, were drilled. The core well was converted into a second monitoring well.

The formation was characterised based on the corehole data and the considerable amount of existing geophysical data throughout the area.

Reservoir modelling activities were led by a team from Advance Resources Int. using COMET3 reservoir simulator. Four types of reservoir modelling was necessary during the course of the project. These were 1) a review of the primary injection sites in the Central Appalachian Basin 2) rigorous history matching and assessment of preferred injection sites including sensitivity runs prior to injection. 3) Midcourse reservoir modelling to assess the performance of the project against expectations allowing mid-course corrections to be made. 4) Post project history matching and performance prediction of the CO2 sequestration pilots and their implications to CO2 storage in the Basin.

The thickness of each of the targeted seams range from 0.7 – 4.0 feet thick for a total thickness of 26.7 feet. The total thickness of coals completed at the well site is 36.2 feet. After the cores were removed for analysis, the core hole was converted into a monitor well and pressure transient tests will be performed in both the core holes and injection well.

Source of CO_2

The carbon dioxide was purchased from *Praxair Inc,* manufacturer of industrial, process and specialty gasses.

Transport of CO_2

The carbon dioxide was delivered to the site in trucks creating an onsite storage capacity of 104 tons.

Additional Project details

The injection well had 4 hydraulic fracture zones with perforations in the target coal seams. The fracture zones were at the following depths:

- 1^{st} fracture zone, 648-692 meters
- 2^{nd} fracture zone, 536-620 meters
- 3^{rd} fracture zone, 494-526 meters
- 4^{th} fracture zone, 318-480 meters.

The injection took place in three (1^{st} -3^{rd}) of the four fracture zones in the well affecting 19 coal seams. The injection pressure was held at below 1000 psi in accordance with the projects UIC permit. Monitoring was conducted during three stages, pre-injection, during injection and post-injection.

Stakeholder engagement

There were a number of outreach methods used during the project as part of a rigorous technology transfer and outreach program to inform and educate public and industry stakeholders. Engagement was conducted though technical and general publications with project information, local, regional and international meetings as well as running a website with posts with project updates.

Risk assessment process

Not known.

Significant learnings from the project

- The project managed to average a higher than anticipated Injection Rate (37 tons per day)
- There was a decrease in Injection Rate (<20 tons per day) was seen which was ascribed to swelling or the filling of hydraulic or natural fractures.
- Results of the tracer detection in off-set wells were unexpected and appeared to indicate that that the plume was larger than anticipated. This has left the tracer results in question as with minimal data points, the results leave a number of questions unresolved
- It was thought possible that the tracer to CO_2 concentration is higher at the offset wells than what was injected due to the tracer not being adsorbed into the coal due to its molecular size being larger than the CO_2 and larger than coal micropores.
- During flowback monitoring during the post injection phase the production returned to higher than pre-injection rates. The well has produced 25% of the injected CO_2 to date and there have been significant tracer concentrations detected in flowback. Long term monitoring of the flowback is ongoing.

PROJECT SUMMARY

Project name:
SECARB Mississippi Test project

Project organisation:
SECARB (Southeast Regional Carbon Sequestration Partnership)

Project type:
Research - Deep Saline Aquifer

Project scale:
Small scale (2,740 t)

Type and depth of reservoir:
Sandstone, 2895 meters

Total cost of project:
US$ 6,750,000

Location:
Escatawpa, Mississippi, USA

Year of first injection:
2008

Current status:
Injection Complete

Type of Seal:
Shale

PROJECT DETAILS

	Project operator	Electric Power Research Institute and Southern Company	**Project contact phone**	770-242-7712
	Project contact	Kenneth J. Nemeth	**Project contact email**	nemeth@sseb.org
	Project location	Escatawpa, Mississippi, USA	**CO_2 source**	Geological source
	Injection site coordinates	30°32'13"N, 88°33'27"W	**CO_2 transport/delivery**	Truck
	Project planning start	2007	**Injection rate**	36 - 163 tonnes per day
	Duration of injection	Less than a year	**Injection pressure**	WHTP 1000-1450 psia
	Planned injection volume	2,721 t	**Total volume injected**	2,746 tonnes
	Reservoir porosity	20.7 % (avg, ambient)	**Reservoir permeability**	1,230 (avg, to air)
MONITORING	**Seismic monitoring**	Pre and post injection VSP	**Gravity studies**	Not performed
	Water monitoring	Shallow sampling/deep fluid sampling	**Pressure logging**	Formation pressure and annulus pressure
	Soil monitoring	Soil flux	**Thermal logging**	Not performed
	Atmospheric monitoring	Not performed	**Wireline logging**	Logging/petrophysics
	Ecological monitoring	Not performed	**Observation well**	One observation well
	Tracer analysis	PFT and surface monitoring	**Geochemical research/Fluid sampling**	From injection well and shallow
	Electromagnetic	Not performed	**InSAR**	Not performed
RESERVOIR STUDIES	**Reservoir modelling**	GEM	**Geologic model**	Petra
	Coring	Whole and sidewall coring	**Seismic**	2 VSP shoots
	Other technologies	Not known		

Project context

Southeast Regional Carbon Sequestration Partnership (SECARB) is one of seven partnerships across the USA formed as part of the US Department of Energy Regional Carbon Sequestration Partnerships (RCSP) initiative, which involved a three phase implementation program. The SECARB Mississippi test project was part of the SECARB Phase II validation project. SECARB Phase II included four field tests. The Mississippi test project formed the program's Saline Reservoir Field Test.

Aims of the project

To identify and validate that deep saline reservoirs located near large coal-fired power plants along the Mississippi Gulf Coast, may be used for safe geological storage of CO_2. To provide a safe, secure and publicly accepted field demonstration project of CO_2 storage in geological formations.

Ownership and liability

The project team was led by the Electric Power Research Institute and Southern Company, owners of Mississippi Power Company. The injection site is on land owned by Mississippi Power Company's Victor J. Daniel Jr. Electric Generating Plant (Plant Daniel).

Mississippi Power Company accepted the post injection CO2 liability.

Regulatory and approval conditions

The Project operated under a Class V UIC Permit granted through the Mississippi Department of Environmental Quality (MDEQ).

Pre-injection geological database and site characterisation

The injection site was located at Mississippi Power Company's Victor J. Daniel Jr. Electric Generating Plant site situated near Escatawpa, Mississippi, USA. The power station property covers around 1,600 acres of land and was underlain by the Lower Tuscaloosa Formation, previously identified as a promising high capacity CO_2 storage option. The Lower Tuscaloosa Formation consists of a massive Cretaceous sand unit common to the Gulf Coast region of the USA. The sand unit is a Cretaceous unit, overlain by a regional seal; the Marine Tuscaloosa Shale. The sites characterisation was an ongoing component of this project including: constructing geological and reservoir maps to further assess the site, conducting reservoir simulations to estimate CO_2 injection rates, storage capacity and long-term fate of injected CO_2..

Whole and sidewall 4 inch coring was carried out - 30 feet Selma Chalk, 26 feet Marine Shale, 58 feet Tuscaloosa Massive Sand. Core tests included porosity, permeability, capillary pressure, XRD, thin section and unsteady state relative permeability

Source of CO_2

The carbon dioxide was obtained from reserves of CO_2 owned by Denbury Resources Inc. at a pipeline outlet in central Mississippi.

Transport of CO_2

The liquid CO_2 was transported in trucks operated by Airgas Carbonic to the injection site. There were deliveries of around 7 trucks a day during the projects pre-injection and injection period. The CO_2 was temporarily stored on-site, heated and injected into the Massive Sand unit of the Lower Tuscaloosa formation.

Additional project details

Mississippi Power Company's Victor J. Daniel Power Plant, located near Escatawpa, Mississippi, was the site for this demonstration project. The Mississippi test project examined a regionally significant deep saline reservoir for geological storage of CO_2. The project began injecting CO_2 in October 2008 and injected a total of around 2,746 tonnes during the pilot project.

The Mississippi Test Site project has provided the essential foundation of technical knowledge for subsequent full-scale, commercial implementation of CO_2 storage activities. Along with detailed site characterisation and geologic studies, the project addressed state and local regulatory regimes for permitting the site; fostering public education and outreach to build acceptance; injecting approximately 2,746 tonnes of CO_2; and conducting baseline and long-term monitoring to establish the security of the CO_2 plume. The results have formed the basis for SECARB Phase III of the RCSP initiative.

Stakeholder engagement

The Mississippi test project maintained engagement with local communities throughout the course of the project. At early stages of the project there was a 'Neighbour meeting' sponsored by Mississippi Power to discuss the project and inform local stakeholders. The meeting was attended by the projects technical team to facilitate interactive discussion with the public using various visual aids (posters, rock samples, etc.) to communicate the projects intentions. The public were also engaged during the permitting and approvals stages of the project, in particular, during a meeting in August, 2007. Mississippi Department of Environmental Quality held this meeting to answer any additional questions and to complete regulatory requirements associated with permitting.

Risk assessment process

- The CO_2 injection pilot at Plant Daniel demonstrated that conventional oilfield injection well design, drilling and completion methodologies can be adapted for use in CO_2 injection well drilling.
- Neither of the deep monitoring methods (vertical seismic profiling and cased-hole neutron logging) were able to track the CO_2 plume in the deep subsurface.
- The use of high-resolution reservoir characterisation tools beyond conventional wireline and coring tools as well as advanced reservoir simulations for accurate plume prediction were essential for designing a successful monitoring program. The early gathering of detailed characterisation data was critical in predicting the short-term migration patterns of the CO_2 plume and the long-term mechanisms of CO_2 immobilisation and required a series of reservoir simulations.

PROJECT SUMMARY

Project name:
South West Hub

Project organisation:
WA Department of Mines and petroleum

Project type:
Deep Saline Aquifer

Project scale:
Small scale (<100,000 t (initially))

Type and depth of reservoir:
Sandstone, 2000-3000 metres depth

Total cost of project:
USD $54 m (AUD $52 m) for feasibility study (April 17, 2013)

Location:
South of Perth, Western Australia

Year of first injection:
To be determined

Current status:
Feasibility study underway

Type of Seal:
Not known

PROJECT DETAILS

	Project operator	WA Department of Mines and Petroleum	**Project contact phone**	+61 9791 2040
	Project contact	Dominique Van Gent	**Project contact email**	Dominique.vangent@dmp.wa.gov.au
	Project location	South of Perth, north of Kemerton, Western Australia	**CO_2 source**	Industrial source from the Collie area
	Injection site coordinates	Approx 32°S, 116°"E	**CO_2 transport/delivery**	Not determined for test; pipeline for the large scale project
	Project planning start	2011	**Injection rate**	To be determined
	Duration of injection	To be determined	**Injection pressure**	To be determined
	Planned injection volume	To be determined. Initially small scale test. Later 2.5 million tonnes/year	**Total volume injected**	None to date
	Reservoir porosity	10-20%	**Reservoir permeability**	0.1-1000mD (mean approx 30mD)
MONITORING	**Seismic monitoring**	2D and 3D	**Gravity studies**	No
MONITORING	**Water monitoring**	Proposed	**Pressure logging**	Yes
MONITORING	**Soil monitoring**	To be determined	**Thermal logging**	To be determined
MONITORING	**Atmospheric monitoring**	To be determined	**Wireline logging**	Yes
MONITORING	**Ecological monitoring**	No	**Observation well**	Not at this stage
MONITORING	**Tracer analysis**	To be determined	**Geochemical research/Fluid sampling**	Yes
MONITORING	**Electromagnetic**	Yes	**InSAR**	No
RESERVOIR STUDIES	**Reservoir modelling**	Yes	**Geologic model**	Yes
RESERVOIR STUDIES	**Coring**	Yes	**Seismic**	VSP
RESERVOIR STUDIES	**Other technologies**	Sonic, resistivity, resonance		

Project context

The area between Mandurah and Bunbury has the potential to be developed as a storage hub for carbon dioxide from surrounding industry, including coal-fired power plants. The project developers aim to store up to 3.3 megatonnes of carbon dioxide per annum in the longer term.

In June 2011, the project received $52 million in funding as part of the Commonwealth Government's CCS Flagship program (http://www.dmp.wa.gov.au/9525.aspx, 2012) for a feasibility study of the storage potential.

Aims of the project

The project aims to examine the potential for CO_2 storage in the Lesueur formation. Depending on the success of feasibility studies, the project would then progress to a commercial scale project.

Ownership and liability

The project is lead by the Western Australian Government, Department of Mines and Petroleum and owned in WA Government – industry partnership with Perdaman Chemicals and Fertilisers, Verve Energy, The Griffin Group, Westfarmers Permier Coal, BHP Billion Worsley Alumina and Alcoa of Australia.

Discussions have been held with landowners, but no agreements are in place at this stage.

Regulatory and approval conditions

A Bill to regulate the onshore storage of CO_2 is currently under preparation for tabling in the WA Parliament.

Pre-injection geological database and site characterisation

The first well, Harvey No. 1, provided excellent material for characterisation of the potential reservoir formation. A comprehensive database is under development for the Harvey No. 1 well.

Source of CO_2

A number of sources exist in the Collie area. No confirmation of any particular source has been made at this stage.

Transport of CO_2

Transport for any small scale trial injection will be potentially by road. Subsequent large scale operation is likely to be by pipeline.

Additional project details

Not known at this time.

Stakeholder engagement

Extensive program of stakeholder engagement including community involvement in:

- Formation of a community reference group.
- Design of project assessment.
- Identification of key issues.
- Monitoring and review of the trials.
- Input into project planning and development.

Risk assessment process

Risk assessment is to be undertaken prior to drilling the first well and during the operation.

Significant learnings from the project

- A lower shale exists in the Eneabba Formation (a potential seal).
- The Lesueur has good porosity and permeability.
- High fracture gradients.
- Stable faults.
- Good residual trapping potential in the Lesueur Sandstone.

PROJECT SUMMARY

Project name:
Surat Basin CCS Project (prev Wandoan)

Project organisation:
Xstrata

Project type:
Deep Saline Aquifer

Project scale:
Small scale test initially

Type and depth of reservoir:
Sandstone, unknown depth

Total cost of project:
Not known

Location:
Approx 300km NW of Brisbane Queensland, Australia

Year of first injection:
To be determined

Current status:
Exploratory/feasibility

Type of seal:
Not known

PROJECT DETAILS

	Project operator	Xstrata	**Project contact phone**	(+61) 02 92536789
	Project contact	James Rickards	**Project contact email**	jrickards@xstratacoal.com
	Project location	Central Queensland, Australia	**CO_2 source**	Source for small scale test yet to be determined. Coal -fired Power plant for large scale
	Injection site coordinates	Approx 26°S, 149°"E	**CO_2 transport/delivery**	Truck for test, pipeline for full scale (151 – 200km)
	Project planning start	To be determined	**Injection rate**	To be determined
	Duration of injection	To be determined	**Injection pressure**	To be determined
	Planned injection volume	Not known for small scale test. Proposed large scale 1million tonnes/year	**Total volume injected**	None to date
	Reservoir porosity	Not known	**Reservoir permeability**	Not known
MONITORING	**Seismic monitoring**	To be determined	**Gravity studies**	To be determined
	Water monitoring	Yes	**Pressure logging**	To be determined
	Soil monitoring	To be determined	**Thermal logging**	To be determined
	Atmospheric monitoring	To be determined	**Wireline logging**	To be determined
	Ecological monitoring	To be determined	**Observation well**	To be determined
	Tracer analysis	To be determined	**Geochemical research/Fluid sampling**	To be determined
	Electromagnetic	To be determined	**InSAR**	To be determined
RESERVOIR STUDIES	**Reservoir modelling**	Yes	**Geologic model**	Yes
	Coring	Yes	**Seismic**	Yes
	Other technologies	Not known		

Project context

The project has recently been restructured and renamed (it was previously the Wandoan project) and is now focussed solely on determining the storage potential of the area within the Surat Basin.

Aims of the project

Using data obtained through oil and gas exploration and production in the Surat Basin, an assessment is underway of the storage potential in the Wandoan area of the Basin. It is anticipated that a new well will be drilled, to be followed by a small scale test injection as part of the feasibility study.

Ownership and liability

Project ownership is by Xstrata Coal.

No specific site has been announced at this stage but the project has been granted a CCS licence by the Queensland Government and and exploration is underway within that tenement area.

Liability arrangements have not yet been announced.

Regulatory and approval conditions

CCS tenement has been granted to the Project in the Surat Basin.

Pre-injection geological database and site characterisation

An extensive database exists for the CCS tenement area, based on public and proprietary data obtained through oil and gas exploration in the region. This information is being used for comprehensive site characterisation.

Source of CO_2

Not known.

Transport of CO_2

CO_2 transport is likely to be road transport for any small scale test.

Additional project details

Not known.

Stakeholder engagement

Some stakeholder engagement has been undertaken by the Project, in the Wandoan region of Queensland.

Risk assessment process

Risk assessment is an ongoing feature of the project.

Significant learnings from the project

- Suitable sandstone reservoirs occur in the tenement area, along with potentially good seals.
- Management of groundwater issues will be an important feature of the Project.

PROJECT SUMMARY

Project name:
SWP San Juan Basin

Project organisation:
Southwest Regional Partnership on Carbon Sequestration (SWP)

Project type:
Enhanced Coalbed Methane

Project Scale:
Small Scale (16,700 t)

Type and depth of reservoir:
Coal, 915 meters

Total cost of project:
US $11,500,000

Location:
Rio Arriba, New Mexico, USA

Year of first injection:
2008

Current status:
Injection Complete

Type of seal:
Stratigraphic (Kirtland Shale)

PROJECT DETAILS

	Project operator	ConocoPhillips	**Project contact phone**	(801) 585-7961
	Project contact	Dr. Brian McPherson	**Project contact email**	b.j.mcpherson@utah.edu
	Project location	Rio Arriba, New Mexico, USA	**CO_2 source**	Geologic (McElmo Dome, Colorado)
	Injection site coordinates	36°45'26"N, 107°35'32"W	**CO_2 transport/delivery**	Pipeline
	Project planning start	2005	**Injection rate**	50 tonnes/day
	Duration of injection, if known	1 year	**Injection pressure**	1,100 psi
	Planned injection volume	68,000 tonnes	**Total volume injected**	16,700 tonnes
	Reservoir porosity	Variable (<1% to 20%)	**Reservoir permeability**	50-100md
MONITORING	**Seismic monitoring**	time-lapse VSP	**Gravity studies**	Not performed
	Water monitoring	Shallow wells	**Pressure logging**	Wellhead and downhole
	Soil monitoring	Surface flux measurement	**Thermal logging**	Wellhead and downhole
	Atmospheric monitoring	Surface flux measurement	**Wireline logging**	Sonic, FMI, gamma ray
	Ecological monitoring	Hyperspectral imaging of land surface	**Observation well**	3 existing producer wells
	Tracer analysis	PFC, PMCH, PTCH	**Geochemical research/Fluid sampling**	Produced water ions, trace metals, isotopes, dissolved organics, CO_2 concentration sampling
	Electromagnetic	Conductivity Profiles	**InSAR**	Limited
RESERVOIR STUDIES	**Reservoir modelling**	Fluid simulations using COMET3	**Geologic model**	Static model
	Coring	Existing information	**Seismic**	Existing information
	Other technologies	Tiltmeter array, geodetic GPS		

Project context

The San Juan project (SJB ECBM/CO_2 Demonstration Test) was an enhanced coalbed methane (ECBM) project that involved CO_2 injection into a deep, unmineable coalbed at the Pump Canyon site located in the San Juan Basin of northern New Mexico.

The San Juan project was run by the Southwest Regional Partnership on Carbon Sequestration (SWP), one of seven partnerships across USA formed as part of the US Department of Energy Regional Carbon Sequestration Partnerships (RCSP) initiative which involved a three phase implementation program. This project was part of the SWPs program in Phase II, as a validation project, one of three geological CO_2 storage projects.

Aims of the project

The aim of this project was to examine ECBM efficacy and amount of CO_2 sequestration through the injection of CO_2 into the coals of the Upper Cretaceous Fruitland formation.

Ownership and liability

The project is owned by the Southwest Regional Partnership on Carbon Sequestration funded by the U.S. Department of Energy and is managed by the National Energy Technology Laboratory. The project was operated by *ConocoPhillips.*

The land where the CO_2 injection well resides is administered by the New Mexico State Lands Office. The surrounding lands are administered by the US Bureau of Land Management (BLM). Pipeline Rights-of-Way traversed NM State and BLM land.

Liability assumed by industry sponsors.

Regulatory and approval conditions

New Mexico has an existing regulatory framework for injection of CO_2. Enhanced gas recovery injection activity is classified as class II under the Underground Injection Control Permit process. The New Mexico Oil Conservation Division has adopted specific regulations governing the long-term geologic storage of CO_2.

Pre-injection geological database and site characterisation

The project involved three existing coalbed methane producing wells and a new centrally located injection well on a 640-acre section. The new well was drilled, logged and cored with the target strata being further analysed during the project's site characterisation.

The project benefited from the nearby Alison Unit injection project's characterisation work. There were three targeted coal seams at 915 metre depth which had a 23m thickness each over a 53m interval. There was very low reservoir pressure and high permeability (50-100md). The site specific characterisation conducted on the newly drilled injection well, together with the Alison unit data were used for numerical models were built with the primary purpose of understanding the pattern of methane production and CO_2 injection movement. Initial forecasting was performed to aid in operational planning.

Source of CO_2

The CO_2 was sourced from a natural geologic accumulation at McElmo Dome, Colorado.

Transport of CO_2

The CO_2 was transported to the injection site via an extension pipeline from the Cortez pipeline.

Additional project details

The 1-year injection test began in mid-2008 and targeted the coal-bearing Fruitland Formation at a depth of approximately 915 m. The SWP test goal was to inject 68,000 tonnes of CO_2 during the year, but reduced injectivity restricted the total CO_2 injected to approximately 18,400 tonnes. However, test results confirm that the San Juan Basin is an excellent target for future CO_2 storage opportunities, especially when considering the large number of nearby power plants, relatively low operating costs, and well-developed natural gas and CO_2 pipeline infrastructure.

Stakeholder engagement

Public and stakeholder outreach was a key objective of the SWP. Working towards this key objective has seen the following activities:

- 10-day program focused primarily on CCS applications using group exercises, field tours, and safety training, now run as an annual event.
- Community Involvement and Outreach Opportunities, tours and demonstrations.
- Town Hall Meetings.
- Student Internships and graduate employment.
- Technology Training Program.

Risk assessment process

No risk assessment was performed.

Significant learnings from the project

- Results suggested that there was possible coal swelling that occurred with the introduction of CO_2 into the coal seams. This made the technology capable of detecting surface and subsurface deformation critical tools for the project.
- While the sensitive instrumentation in and around the injection site has detected swelling, the results do not reflect systematic trends.

PROJECT SUMMARY

Project name:
Teapot Dome Wyoming

Project organisation:
Rocky Mountain Oilfield Testing Center (DOE funded)

Project type:
Enhanced Oil Recovery

Project scale:
Small scale (<100,000 t)

Type and depth of storage reservoir:
Sandstone, 1,675 m

Total cost of project:
Suggested possible cost: Baseline $1.6M, approx $5M/yr after that

Location:
Wyoming, USA

Year of first injection:
Suggested for 2005-2006

Current status:
Project abandoned – contacts not reachable

Type of seal:
Marine Shales

PROJECT DETAILS

	Project operator	Rocky Mountain Oilfield Testing Centre	**Project contact phone**	(307) 261-5000
	Project contact	Doug Tunison	**Project contact email**	doug.tunison@rmotc.doe.gov
	Project location	Wyoming, USA	**CO_2 source**	Gas processing
	Injection site coordinates	43°17'19"N, 106°10'24"W	**CO_2 transport/delivery**	Truck/pipeline
	Project planning start	2003	**Injection rate**	NA
	Duration of injection	Expected 10 years	**Injection pressure**	NA
	Planned injection volume	Not known	**Total volume injected**	NA
	Reservoir porosity	Avg 8% (Tensleep Formation) Avg 15% (Second Wall Creek)	**Reservoir permeability**	Avg 80 md (Tensleep Formation) Avg 100 md (Second Wall Creek)
MONITORING	**Seismic monitoring**	VSP	**Gravity studies**	Not performed
	Water monitoring	Not performed	**Pressure logging**	Not performed
	Soil monitoring	Soil gas	**Thermal logging**	Not performed
	Atmospheric monitoring	Not performed	**Wireline logging**	Not performed
	Ecological monitoring	Not performed	**Observation well**	Not performed
	Tracer analysis	Not performed	**Geochemical research/Fluid sampling**	Not performed
	Electromagnetic	Not performed	**InSAR**	Not performed
RESERVOIR STUDIES	**Reservoir modelling**	Not performed	**Geologic model**	Not performed
	Coring	Existing data	**Seismic**	Existing
	Other technologies	Not known		

Project context

The Teapot Dome site in Wyoming, which is the only oilfield owned by the US Government, was originally proposed as an appropriate site for carbon storage research by the DOE as far back as 2002.

The field which has a rich history of oil exploration and production became US Government owned in 1927 and has since been subject to much exploration and research. The project proposed large scale injection of CO_2 into saline reservoirs as a means to investigate Enhanced Oil Recovery (EOR) and CO_2 storage.

However, although there was a considerable amount of research on baseline characterisation of the reservoir, the project never attracted federal funding and appears to have now been abandoned, although it was still being reported as a potential project in 2009.

Aims of the project

Although the site was proposed as an ideal place to test many aspects of geological storage including economics, viability and reliability (*Friedmann et al 2004)*; it does not appear that a detailed project plan has ever been developed.

The initial project aims were to provide a field-scale, storage-optimised project in the U.S., improve understanding of leakage risks and related issues and develop and compare MM&V technologies at a field scale.

Ownership and liability

The injection site is owned by the U.S Department of Energy and run by the Rocky Mountain Oilfield testing center, who were anticipated to be the operators of any project.

Regulatory and approval conditions

As the project and the site is Government operated, the recovery of oil or gas and the storage of CO_2 are not constrained as an economic recovery project and can be operated solely for the benefit of science and engineering research.

Pre-injection geological database and site characterisation

The site has been used as a research and exploration for many years and presented a unique opportunity for a CCS project as a consequence of its history with over 2,200 wells in total, of which over 1,200 are accessible. All cores, well logs, mud logs, completion descriptions, and production data from these wells as well as full-field 3D seismic have been created. Data sets include geological, geophysical, geochemical, geomechanical and operational data over a wide range of geological boundary conditions, and were made available in the public domain.

The baseline monitoring programs began in late 2003 as part of the comprehensive site characterisation to support the proposed CO_2 injection and other experiments. Investigations included noble gas characterisation (University of Manchester), soil gas surveys (Colorado School of Mines), vertical seismic profiling and extended techniques (Lawrence Berkeley National Laboratory), electrical resistance tomography (Lawrence Livermore National Laboratory), and hyperspectral airborne surveys (Lawrence Livermore National Laboratory) *(Friedmann, Stamp, 2005).*

Source of CO_2

The CO_2 was to be sourced from nearby anthropogenic supplies.

Transport of CO_2

It was suggested that CO_2 could be transported to site through existing pipelines with the addition of a CO_2 pipeline from Salt Creek field immediately adjacent to Teapot Dome's northern field boundary completed by Anadarko Petroleum Corporation.

Additional project details

The Teapot Dome site is the only oil field currently owned and operated by the U.S. federal government, which makes it possible to propose and carry out scientific experiments and technical development programs within a long-term, stable business context, free of the commercial drivers of a privately-owned oil field.

Although this seemed to be a promising opportunity for further investigations into CO_2 storage and EOR, the project does not seem to have proceeded, possibly due to a lack of federal funding.

Stakeholder engagement

Not known.

Risk assessment process

Leak risk characterisation was investigated to understand the leak potential of faults within the field prior to the planned injection. The fault geometry and in-situ stress patterns were characterised near the proposed Section 10 injection site in order to better predict the risks associated with fault reactivation due to fluid injection and pressure transients.

Significant learnings from the project

No significant scientific learnings as this project was never initiated.

PROJECT SUMMARY

Project name:
Western Kentucky Carbon Storage Test

Project organisation:
Kentucky Geological Society

Project type:
Deep Saline Aquifer

Project scale:
Small scale (626 t)

Type and depth of reservoir:
Dolomite (Cam-Ord Knox group), 1st 1115m, 2nd 1535m

Total cost of project:
US$8,000,000

Location:
Hancock County, Kentucky, USA

Year of first injection:
2009

Current status:
Injection complete, borehole was plugged and abandoned in 2011

Type of Seal:
Shales

PROJECT DETAILS

	Project operator	Kentucky Geological Survey	**Project contact phone**	(859) 323-0536
	Project contact	(Principal Investigator) J. Richard Bowersox	**Project contact email**	j.r.bowersox@uky.edu
	Project location	Hancock County, Kentucky USA	**CO_2 source**	Food grade CO_2 from commercial source
	Injection site coordinates	37°51'20"N, 86°46'00"W	**CO_2 transport/delivery**	Truck
	Project planning start	2007	**Injection rate**	1st – 2nd tests: 0.5 m^3/minute
	Duration of injection	1st in 2009, one day 2nd in 2010, one day	**Injection pressure**	1st test: 6.5 MPa surface, 12.1 MPa in the reservoir at 1115 m 2nd test: 6.4 MPa surface, 17.5 MPa in the reservoir at 1545 m
	Planned injection volume	626 tonnes of CO_2 and 282,638.7 tonnes of brine	**Total volume injected**	626 tonnes of CO_2 and 282,638.7 tonnes of brine
	Reservoir porosity	1st test 6.5%, 2nd test 9.0%	**Reservoir permeability**	1st test 9.3 mD 2nd test 12.5 mD
MONITORING	**Seismic monitoring**	2nd test: Time lapse VSP	**Gravity studies**	Not performed
	Water monitoring	Geochemical analyses of two domestic water wells and two developed springs for 41 months in 2009 – 2012	**Pressure logging**	Wellhead and downhole
	Soil monitoring	Baseline survey in 2008	**Thermal logging**	Wellhead and downhole
	Atmospheric monitoring	Not performed	**Wireline logging**	No dedicated well
	Ecological monitoring	Not performed	**Observation well**	Not performed
	Tracer analysis	Not performed	**Geochemical research/Fluid sampling**	Two reservoir fluid samples: CO_2-brine-rock interactions models of reservoirs and seal
	Electromagnetic	Not performed	**InSAR**	Not performed
RESERVOIR STUDIES	**Reservoir modelling**	1st – 2nd tests: Pressure transient analysis completed	**Geologic model**	Completed
	Coring	Existing from new well	**Seismic**	2D and 3D
	Other technologies	Imaging log		

Project Context

The Western Kentucky project was a unique project from its inception, born out of a mandate from Kentucky General Assembly's House Bill 1. The project injected 626 tonnes of CO_2 in two injections into the Beekmantown Dolomite and Gunter Sandstone of the saline Knox Group in Kentucky.

Aims of the project

The aim of this project is to demonstrate CO_2 storage and the integrity of sealing strata for long term storage in deep saline reservoirs in the Illinois Basin, Western Kentucky, USA. In demonstrating the storage of CO_2 in the area, the project aims to validate appropriate technologies and methodologies and publish all outcomes for government, industry and public evaluation.

Ownership and liability

The project was undertaken by the Kentucky Geological Survey (KGS), mandated and partially funded from a $5 million grant awarded to the geological survey from the Kentucky Department for Energy Development and Independence from appropriations from the Kentucky General assembly. Additional financial support for this project came from contributions by the Western Kentucky Carbon Storage Foundation (2008 – 2011), an industry organisation created specifically to fund the project; the Tennessee Valley Authority; the Illinois Department of Commerce and Economic Opportunity, Office of Coal Development; and U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory. The drill site was privately owned and had an oil and gas leaseholder through August 2010. Access was granted to KGS for the duration of the project. KGS owned the well and associated facilities which operated in an agreement with the landowner for site access and adjacent areas for monitoring. Liability for the project was assumed by KGS.

Regulatory and approval conditions

This project was initiated by legislative changes during August 2007, which saw Kentucky's General Assembly raise House Bill 1, for KGS to research the geologic storage of CO_2 in Kentucky.

Permitting was required for well drilling, construction activities and injection plans. The U.S. Environmental Protection Agency permitting requirements included well design and construction, groundwater geochemical monitoring, injection pressure limitations, and plugging. Kentucky Division of Oil and Gas permitting requirements included the well location survey, well design and construction, directional control, and plugging.

This project set the tone for prompts for Kentucky to develop regulatory framework for CO_2 storage, permitting and assessments and long term maintenance.

Pre-injection geological database and site characterisation

Kentucky Geological Survey No. 1 Marvin Blan well was drilled in 2009. This well was used for characterisation and two injection tests. The characterisation included a total of 120 metres of whole-diameter cores cut in the well and the recording of an extensive suite of geophysical logs. The Ordovician Maquoketa Shale and Black River Group were cored to test their sealing capacity, and the Knox was cored to test its reservoir properties. Evaluation of the well and core data indicated that the Knox had reservoir properties suitable for CO_2 storage, and that the overlying Maquoketa and the Black River group had sealing capacity sufficient for long-term confinement.

Source of CO_2

The food-grade carbon dioxide was obtained from Praxair, a commercial source.

Transport of CO_2

The carbon dioxide was trucked to the injection site. Brine was mixed at the well site with water from the Hancock County municipal water system.

Additional project details

The test injection site was located in east-central Hancock County, about 4 miles southeast of the Ohio River, Kentucky. The test well was located on the easternmost margin of the West Kentucky Coal Field. The location was selected as means to evaluate the CO_2 storage characteristics of the Knox Group, a geologic formation that has a broad distribution in Kentucky and the mid-continent USA. The research project had two test injections with brine and CO_2, the first test injected 393 tonnes of CO_2 into the below a packer set in casing at 1098 meters deep. The second phase tested a mechanically-isolated dolomitic-sandstone interval at 1535–1605 meters. Results of these tests were used to build CO_2 storage reservoir models and further evaluate the storage capacity in the Knox Group in Kentucky.

Stakeholder engagement

This project was accompanied by public engagement program with a series of public presentations and information sessions as well as utilising local and regional print and television media. Print media stories ran across a number of forums including journals, local newspapers, news releases, and political forums. Television news stories reported the public meetings and wellsite visits. These methods of engagement occurred throughout the proposal, approvals, operational and post injection stages.

Risk assessment process

Risk assessments of all aspects of the project were performed prior to drilling. Assessments were made of the surface environmental state of the well site; geologic risks of finding a suitable reservoir with a seal sufficient to ensure long-term storage and confinement of CO_2 in the deep subsurface; the absence of faults and fractures near the wellbore that might have compromised the seal integrity; groundwater contamination of CO_2 migrating from the storage reservoir; health, safety, and environmental risks of the drilling and testing programs; well construction and plugging; and financial cost controls.

Significant learnings from the project

- The Knox dolomite extends over most of the West Kentucky Coal Field with properties comparable to that in the KGS test well. This indicates that that the formation will be suitable for CO_2 storage over much of this area.
- The Knox dolomite has reservoir properties suitable for geologic storage of CO_2 in deep saline reservoirs. Porous units within the Knox Dolomite could serve as an effective CO_2 storage reservoir for much of mid-continent USA. Additional evaluation of the Knox Dolomite will be necessary to fully determine its potential for CO_2 storage.
- There are excellent reservoir sealing strata in the Black River Limestone and overlying Maquoketa Shale, above the Knox Dolomite, that would prevent any CO_2 migration from the Knox Dolomite to the surface.
- The Precambrian Middle Run Sandstone, which was cored in the #1 Marvin Blan well at 2438 – 2448 m, showed no potential for CO_2 storage because the porosity and permeability of the unit had been reduced by diagenetic pore-filling cements to a point that they were negligible.
- The projects quick progression through the planning and permitting phases and its success was assisted by addressing public concerns about the project; thorough technical preparation; industry and political interest for the projects results; and cooperation from the landowner and minerals lessor.

PROJECT SUMMARY

Project name:
West Pearl Queen

Project organisation:
Sandia Nat Labs

Project type:
Deep Oil and Gas Reservoir

Project scale:
Small scale

Type and depth of reservoir:
Sandstone, 1372 meters

Total cost of project:
Not known

Location:
New Mexico, USA

Year of first injection:
2002

Current status:
Injection complete

Type of seal:
Not known

PROJECT DETAILS

	Project operator	Pecos Petroleum	**Project contact phone**	(505) 844-9092
	Project contact	H. Westrich	**Project contact email**	hrwestr@sandia.gov
	Project location	Hobbs, NM, USA	**CO_2 source**	Commercial
	Injection site coordinates	32°42'15"N, 103°08'20"W	**CO_2 transport/delivery**	Truck
	Project planning start	2001	**Injection rate**	40 tons/day
	Duration of injection	Two months	**Injection pressure**	2900 psi (bottom hole constraint)
	Planned injection volume	Several thousand tonnes	**Total volume injected**	2090 tonnes
	Reservoir porosity	15-20%	**Reservoir permeability**	Up to 200 mD
MONITORING	**Seismic monitoring**	3D crosswell, Dipole sonic	**Gravity studies**	Not performed
	Water monitoring	Not performed	**Pressure logging**	Wellhead and downhole
	Soil monitoring	Not performed	**Thermal logging**	Wellhead and downhole
	Atmospheric monitoring	Not performed	**Wireline logging**	Not mentioned
	Ecological monitoring	Not known	**Observation well**	3 existing monitoring/producing
	Tracer analysis	Not performed	**Geochemical research/Fluid sampling**	Composition analysis from produced fluids
	Electromagnetic	Not performed	**InSAR**	Not performed
RESERVOIR STUDIES	**Reservoir modelling**	ECLIPSE, FLOTRAN	**Geologic model**	Not known
	Coring	Existing information	**Seismic**	3D and existing information
	Other technologies	Not known		

Project Context

The West Pearl Queen Field is located near Hobbs in South Eastern New Mexico. In late 2002 and early 2003, a small scale test was carried out into a depleted oil sandstone reservoir.

The West Pearl Queen CO_2 Demonstration project was the first U.S. field demonstration project on CO_2 sequestration in a depleted oil reservoir. The project was developed and sponsored by the U.S Department of Energy (DoE) as a micro-pilot study with three phases, 1) baseline characterisation, 2) CO_2 injection and soaking, 3) post-injection characterisation.

Aims of the project

The project aimed to 1) characterise the oil reservoir and its sequestration capacity; (2) better understand CO_2 sequestration-related processes; and (3) predict and monitor the migration and ultimate fate of CO_2 after injection into a depleted sandstone oil reservoir.

Ownership and liability

The project was owned by DoE. All field preparations, surveys and injection operations were conducted by Strata Production Company. The West Pearl Queen field is owned and operated by Strata Production Company of Rowell, New Mexico.

Liability arrangements are not known.

Regulatory and approval conditions

Being USA's first field demonstration of CO_2 sequestration, one of the project goals was to undertake a project specifically targeted towards sequestration studies, in order 1) for it to become an acceptable technology, 2) to assist in development of a regulatory regime, and 3) to better understand and address safety issues. Injection permitting and well preparations were amongst the mentioned regulatory activities required for the project.

Pre-injection geological database and site characterisation

Phase I of the project was dedicated to site characterisation. This included the compilation of a geologic model of the depleted reservoir, the evaluation of available flow and reaction simulators, well preparation, the acquisition of legal permits, the collection of reservoir fluids, and baseline geophysical surveys of the reservoir. The target reservoir was the Permian Queen Formation in a small domal structure about 7-8 meters in thickness and lying at 1372 meters depth. There were no known natural fractures found in the sample cores from a well nearby the injection well. The main reservoir is a poorly cemented, oil stained sandstone.

Prior to injection a 3D/9C seismic was conducted along with other geophysical surveys. A second 3D/9C survey was conducted prior to venting.

Source of CO_2

The CO_2 was purchased from a commercial source, the Kinder Morgan CO_2 Company.

Transport of CO_2

The CO_2 was transported to the injection site by truck.

Additional project details

The West Pearl Queen injection site had not been subject to any secondary enhanced oil recovery with water or CO_2, prior to the test which took place in late 2002 and early 2003.

The focus of the project was on characterisation of CO_2 migration through an integrated study that included field/laboratory experiments and numerical simulations. Injection took place over a two month period and this was followed by a six month "soaking" period after which the CO_2 was reproduced and vented.

Stakeholder engagement

Not known.

Risk assessment process

Not known.

Significant learnings from the project

- The reservoir pressure response during the soak period indicates that a steady state was achieved during which the CO_2 did not migrate away from the injected plume.
- Compositional analyses of the samples collected during venting operations, indicated that the CO_2 had interacted with the reservoir oil in place.
- Only a fraction of the CO_2 injected was recovered during venting and production rates were significantly lower than expected. It is suggested in the summary report that this might be due to formation damage close to the well bore as an effect of the CO_2 injection.

PROJECT SUMMARY

Project name:
WESTCARB Arizona Pilot (Cholla)

Total cost of project:
US$ 5,500,000

Project organisation:
The West Coast Regional Carbon Sequestration Partnership (WESTCARB)

Location:
Northern Arizona, USA

Project type:
Deep Saline Aquifer

Year of first injection:
Was planned for 2008

Project scale:
Small scale(<100,000 t)

Current status:
Cancelled

Type and depth of reservoir:
Sandstone, 1170 meters

Type of Seal:
Alternating layers of anyhydrite and shale (Supai formation)

PROJECT DETAILS

	Project operator	WESTCARB	**Project contact phone**	510-486-6456
	Project contact	Larry Myer	**Project contact email**	LRMyer@lbl.gov
	Project location	Northern Arizona, USA	**CO_2 source**	Food Grade
	Injection site coordinates	34°56'82"N, 110°18'35"W	**CO_2 transport/delivery**	Truck
	Project planning start	2006	**Injection rate**	NA
	Duration of injection	NA	**Injection pressure**	NA
	Planned injection volume	Up to 2000 tonnes	**Total volume injected**	None to date
	Reservoir porosity	Avg: 10.5% (Martin)	**Reservoir permeability**	Mean: 0.015 md (Martin)
MONITORING	**Seismic monitoring**	VSP, Crosswell	**Gravity studies**	Not performed
	Water monitoring	Not mentioned	**Pressure logging**	Wellhead and downhole
	Soil monitoring	Surface flux measurement	**Thermal logging**	Wellhead and downhole, DTPS
	Atmospheric monitoring	Flux chambers/eddy covariance	**Wireline logging**	GR, Resis, salinity, sonic, saturation
	Ecological monitoring	Not known	**Observation well**	No dedicated well
	Tracer analysis	Not performed	**Geochemical research/Fluid sampling**	Composition analysis from produced fluids
	Electromagnetic	Not performed	**InSAR**	Not performed
RESERVOIR STUDIES	**Reservoir modelling**	TOUGH2, EOS7C	**Geologic model**	Not known
	Coring	Not known	**Seismic**	Not known
	Other technologies	Not known		

Project context

The WESTCARB Arizona Utilities CO_2 Storage Project was a small research project to examine the CO_2 storage potential of the saline aquifers of the Pennsylvanian Naco and the Devonian Martin Formations of the Arizona Plateau.

The project was operated by the West Coast Regional Carbon Sequestration Partnership (WESTCARB), which is one of seven partnerships across USA formed as part of the US Department of Energy (DOE) Regional Carbon Sequestration Partnerships (RCSP) initiative which involved a three phase implementation program. The WESCARB Arizona Pilot project was part of the DOE funded program in Phase II validation.

Aims of the project

The WESTCARB Arizona Pilot aimed to acquire field data on the feasibility of CO_2 storage in the Colorado Plateau's saline formations in northeastern Arizona, an area with sizeable coal reserves and several large coal-fired plants.

The overall goal of the project was to demonstrate that geologic sequestration is a safe and permanent method to mitigate GHG emissions. In addition, the pilot test had three specific objectives to 1) demonstrate the feasibility of CO_2 storage in the saline formations of the Colorado Plateau region in Arizona, 2) demonstrate and test methods for monitoring CO_2 storage projects in consolidated sandstone, shale and carbonate fields. 3) gain experience with regulatory permitting and public outreach associated with CO_2 storage in a saline formation in Arizona. (DOE Fact Sheet)

Ownership and liability

The project was owned by the WEST Coast Regional Partnership and was conducted on land owned by the Arizona Public Service Company(APS).

Land ownership and liability arrangements are not known.

Regulatory and approval conditions

Not known.

Pre-injection geological database and site characterisation

As part of the Arizona Utilities CO_2 Storage Pilot In 2009, a characterisation well was drilled through sedimentary layers to basement, approximately 1170 meters deep, next to the ash pond of Arizona Public Service's Cholla Power Plant, near Holbrook. Highly saline waters and good sealing formations were found there; however, drill stem tests and well logs indicated insufficient permeability in the target formations to support a commercial-size project at this location.

Source of CO_2

The project purchased food grade carbon dioxide.

Transport of CO_2

The carbon dioxide was transported to the injection site by truck.

Additional project details

Not known.

Stakeholder engagement

Stakeholder engagement began in the planning phase of the project. Events that were conducted as part of the project's engagement activities included:

- Public outreach meetings were held during August 2007 and November 2008 in Holbrook, Arizona, to inform elected officials, safety officials, community leaders, and the public about the project at the Cholla site and to invite their questions and involvement.
- Partners' media release on the public meetings and WESTCARB interviews during the course of the Cholla project resulted in several news articles.

Risk assessment process

Not known.

Significant learnings from the project

- The cancellation of the project was related to insufficient permeability in the target injection zone.
- Despite the localised finding of low permeability at the Cholla site, estimates of the overall CO_2 storage potential in the Colorado Plateau remain high because of the thickness of deep-lying, porous saline formations and the presence of good seals.
- Alternative targets exist (e.g. Tapeats Sandstone)

PROJECT SUMMARY

Project name: WESTCARB Northern California CO_2 Reduction Project	**Total cost of project:** Not known
Project organisation: California Energy Commission (as part of the West Coast Regional Carbon Sequestration Partnership (WESTCARB) in collaboration with C6 Resources LLC	**Location:** Montezuma Hills, Solano County, California, USA
Project type: Deep Saline Aquifer	**Year of first injection:** Planned for 2011
Project scale: Small scale (5,400 t planned)	**Current status:** Cancelled
Type and depth of reservoir: Sandstone, 3350 meters	**Type of Seal:** Three shale layers between 1000-2000 meters

PROJECT DETAILS

	Project operator	California Energy Commission	**Project contact phone**	(916) 327 1370
	Project contact	Mike Gravely, Elizabeth Burton	**Project contact email**	mgravely@energy.state.ca.us; eburton@lbl.gov
	Project location	Montezuma Hills, CA, USA	**CO_2 source**	Commercial
	Injection site coordinates	38°05'35"N, 121°48'22"W	**CO_2 transport/delivery**	Truck
	Project planning start	2007	**Injection rate**	NA
	Duration of injection	Proposed 2 months	**Injection pressure**	NA
	Planned injection volume	5,440 tonnes	**Total volume injected**	None to date
	Reservoir porosity	Not known	**Reservoir permeability**	Not known
MONITORING	**Seismic monitoring**	Yes	**Gravity studies**	No
	Water monitoring	Yes	**Pressure logging**	Yes
	Soil monitoring	Yes	**Thermal logging**	Yes
	Atmospheric monitoring	Yes	**Wireline logging**	Yes
	Ecological monitoring	No	**Observation well**	(proposed) Dedicated well
	Tracer analysis	Yes	**Geochemical research/ Fluid sampling**	Yes
	Electromagnetic	No	**InSAR**	No
RESERVOIR STUDIES	**Reservoir modelling**	Yes	**Geologic model**	Developed
	Coring	Existing information	**Seismic**	Existing information
	Other technologies	Reactive transport simulations (TOUGH2)		

Project context

The WESTCARB Northern California CO_2 Reduction Project was planned as an injection project in Solano County, California. Characterisation work for the project was completed but plans to proceed to injection were dropped in 2010.

The West Coast Regional Carbon Sequestration Partnership (WESTCARB) is one of seven partnerships across the USA formed as part of the US Department of Energy (DOE) Regional Carbon Sequestration Partnerships (RCSP) initiative which involves a three-phase implementation program. The WESTCARB Northern California CO_2 Reduction Project was to have been performed with *C6 Resources, LLC*.

Aims of the project

The project aimed to provide data for detailed characterisation of the site and provide opportunity for preliminary assessment of the site and region for commercial CO_2 storage potential in California.

Ownership and liability

C6 Resources LLC obtained surface and subsurface access agreements for a rural site in Solano County, near the south-western edge of the southern Sacramento Basin. The injection site and the land surrounding it are privately owned. C6 Resources provided, or was to provide, cost share, permitting, well construction and assume associated liability.

Regulatory and approval conditions

Permitting for both the observation and injection well were necessary for this project. The project had applied for an Underground Injection Control Permit for a Class V (experimental well) to the EPA Region 9, in August 2009. This permit was in process, through the public comment period, when C6 Resources withdrew it.

Pre-injection geological database and site characterisation

WESTCARB's Phase I regional screening assessed the Sacramento Basin in the northern part of California's Central Valley (386 km long and 80 km wide) as having a storage capacity of 50-250 billion metric tons of CO_2. The Central Valley is characterised by multiple massive sandstone and shale sequences that host most of California's oil reservoirs in the south (San Joaquin Valley) and natural gas reservoirs in the north (Sacramento Basin). The lithology and structure are representative of the formations that have trapped large accumulations of hydrocarbons, but at the project location and target depths, the reservoir fluid is brine (*Factsheet 4.11.09*). The proposed target formation was the Anderson Formation, saline sandstone units at a depth of 3350 meters. The plan was for one observation well and one injection well to be drilled as part of the project.

Source of CO_2

The CO_2 was planned to be purchased from a local supplier.

Transport of CO_2

Transport of the CO_2 was planned to be by truck.

Additional project details

The proposed project site was in the south-western part of the Sacramento Basin, near the Kirby Hills and Rio Vista natural gas storage fields.

The parent company, Shell Oil, of C6 Resources, LLC made a strategic business decision not to proceed with well drilling.

Stakeholder engagement

Stakeholder engagement was an important component of the project. From the beginning, support from stakeholders was sought. The activities conducted included:

- Obtain agreement with the landowner for the pilot test. Surface and subsurface access agreements in place by April 2009.
- Submit an Underground Injection Control (UIC) permit application in August 2009 to U.S. EPA Region 9, which was successful until the time it was withdrawn.
- Submit permit applications for surface construction activities to the Solano County Planning Board in December 2009. All questions raised by the Board, including the issue of induced seismic, were successfully addressed.
- Ongoing public meetings with local officials, landowners, and nearby communities. The project was generally well regarded by all local stakeholders.

Risk assessment process

C6 Resources prepared an internal pre-project risk assessment using their in-house procedures. WESTCARB prepared a preliminary leakage risk assessment for the Montezuma Hills site using LBNL's Certification Framework methodology.

Significant learnings from the project

- This project was a pilot to evaluate whether the site would be favourable for a commercial-scale CO2 storage project. C6 Resources' parent company, Shell Oil, decided that its strategic objectives could be better met by other CCS projects internationally. The ongoing regulatory uncertainty surrounding CCS in the context of California's cap-and-trade and emissions reduction laws may have also had some bearing on the decision to pursue other CCS opportunities outside of California instead of this project.
- From a technical and regulatory standpoint, the lessons learned associated with requests for information on seismic hazards may be most transferable to other projects. Solano County permitting authorities desired to understand the seismic risks associated with injection and requested that Lawrence Berkeley and Lawrence Livermore National Laboratories develop an independent report on the issue, which is now publicly available. This report has been a foundation for defining additional WESTCARB research into seismic hazard issues, which is ongoing.

PROJECT SUMMARY

Project name:
WESTCARB Rosetta – Calpine

Project organisation:
The West Coast Regional Carbon Sequestration Partnership (WESTCARB)

Project type:
Deep Saline Aquifer (Test 1) and
Enhanced Gas Recovery (Test 2)

Project scale:
Small scale

Type and depth of reservoir:
Test 1= Sandstone, 1067 meters
Test 2= Shales, 928 meters

Total cost of project:
US$ 6,000,000

Location:
Rio Vista, CA, USA

Year of first injection:
Planned for 2009

Current status:
Cancelled

Type of Seal:
Shale

PROJECT DETAILS

	Project operator	Rosetta Resources Inc.	**Project contact phone**	(916) 651-2073
	Project contact	Larry Myer	**Project contact email**	LRMyer@lbl.gov; Larry.myer@ucop.edu
	Project location	Rio Vista, CA, USA	**CO_2 source**	Manufactured (Commercial)
	Injection site coordinates	38°12'50"N, 121°26'15"W	**CO_2 transport/delivery**	Truck
	Project planning start	2007	**Injection rate**	Test 1= 60 tonnes/day Test 2= 35 tonnes/day
	Duration of injection	No injection	**Injection pressure**	2 kg/s (suggested)
	Planned injection volume	2000 ton each test	**Total volume injected**	None to date
	Reservoir porosity	35% (preliminary estimate of homogeneous formation properties)	**Reservoir permeability**	1000 md (preliminary estimate of homogeneous formation properties)
MONITORING	**Seismic monitoring**	VSP and crosswell	**Gravity studies**	Not performed
	Water monitoring	Water column	**Pressure logging**	Not performed
	Soil monitoring	Surface flux monitoring	**Thermal logging**	Not performed
	Atmospheric monitoring	Flux Chambers	**Wireline logging**	Not performed
	Ecological monitoring	Not known	**Observation well**	One dedicated well
	Tracer analysis	Not performed	**Geochemical research/Fluid sampling**	Not performed
	Electromagnetic	Formation conductivity/EM induction	**InSAR**	Not performed
RESERVOIR STUDIES	**Reservoir modelling**	TOUGH2/EOS7C	**Geologic model**	Not known
	Coring	Existing information	**Seismic**	Existing information
	Other technologies	Not known		

Project context

The WESTCARB Rosetta- Calpina Project was a proposed pilot test is in a small-depleted and abandoned natural gas field located north of Thornton, California. The project was scheduled to begin in 2009, but was cancelled due to operational reasons before injection activities started.

The West Coast Regional Carbon Sequestration Partnership (WESTCARB) is one of seven partnerships across USA formed as part of the US Department of Energy (DOE) Regional Carbon Sequestration Partnerships (RCSP) initiative which involved a three phase implementation program. The WESCARB Rosetta –Calpine Phase II Project was supported by *Shell Oil Company.*

Aims of the project

Although the overall aim was to gain practical experience and demonstrate the potential for supercritical CO_2 storage in representative geologic formations in an area with large CO_2 sources and storage potential, there were five objectives. These included *(Factsheet, 2007):*

- Test the feasibility and safety of CO_2 storage in a depleted gas field in Northern California;
- Evaluate the feasibility of CO_2 storage with Enhanced Gas Recovery (CSEGR) associated with the early stages of a CO_2 storage project in a depleted gas field;
- Demonstrate the safety and feasibility of CO_2 storage in saline formations in the vast northern regions of the Central Valley, California;
- Demonstrate and test methods for monitoring CO_2 storage projects in gas fields; and
- Gain experience with regulatory permitting and public outreach associated with CO_2 storage in gas reservoirs and saline formations in California.

Ownership and liability

The project was owned by WESTCARB and operated by Rosetta Resources.

Ownership of the surrounding land and liability arrangements are not known.

Regulatory and approval conditions

Not known.

Pre-injection geological database and site characterisation

The proposed site was the depleted Thornton Gas Field, Thornton was an excellent geologic analog to numerous gas fields in the Sacramento Valley, including the much larger 9.3 x 1010 m3 (3.3 Tcf) Rio Vista Gas Field located a few miles away near Rio Vista, California. Thornton was also selected based on evidence of a favourable set of stacked gas reservoirs and saline formations, its close proximity to major transportation corridors, shallow depth to the gas pay zone 928 (3044 feet) and geologic evidence of a well-defined stratigraphic gas trap that could safely hold the CO_2.

The first injection test had planned to inject 2000 tonnes of CO_2 into the McCormick sand, a very fine to medium grained quarzitic sandstone with an injection well and observation well installed in a saline zone beneath the gas accumulation in the same formation at an approximate depth of 1037-1067m.

The second injection test had planned to inject 2000 tonnes of CO_2 into a depleted gas reservoir located within the middle Capay Shale at approximately 928m depth. The Capay shale unit represents a regionally extensive reservoir seal containing pockets of natural gas and interbedded sand lenses. The test planned to inject CO_2 into the depleted gas zone to assess the nature and extent of reservoir pressurisation and displacement of methane by CO_2.

Source of CO_2

The project planned to purchase CO_2 from a local supplier.

Transport of CO_2

Transport of the CO_2 was planned to be by truck.

Additional project details

Gas production from the Thornton gas field began in the mid 1940s and continued through the late 1980s. The site was also selected based on evidence of stacked gas reservoirs and saline formations, its close proximity to major transportation corridors, shallow depth to the gas pay zone and geologic evidence of a well-defined stratigraphic gas trap to safely trap the CO_2 in formation (*Factsheet, 2007*).

The cancelation of this project was reported to be due to organisational reasons and not related to the feasibility of the project itself. It has been suggested that this may have been due to the proximity of a similar project, also into a low quality reservoir. However, the WESTCARB Northern California CO Reduction Project, which also did not proceed to injection, was developed in the same area in cooperation with Shell.

Stakeholder engagement

Outreach activities were an important part of WESTCARB's program. The activities included stakeholder meetings also interacting with California Forest Products Commission and Oregon Forests Resources Institute.

WESTCARB acknowledged efforts locating a CCS project in California revealed a strong need to evaluate and analyse impacts of socioeconomic factors and other non-engineering factors and establish if the site selection criteria impact on specific types of communities and populations disproportionally.

The partnership has made it a specific goal to continue through a Phase III project to work on expanding outreach and education activities, to engage in activities that support the recommendations of the state regulatory panels, the Californian Energy Commission and other regulators to coordinate on CCS policies and regulation developments.

Risk assessment process

Not known.

Significant learnings from the project

- Not known.

PROJECT SUMMARY

Project name: ZeroGen IGCC with CCS	**Total cost of project:** USD $199,665,000 (AUD $194,000,000 to end Prefeasiblity Stage (total expected cost $6.9 billion))
Project organisation: Queensland Government	**Location:** Central Queensland, Australia
Project type: Large Scale Deep saline Aquifer	**Year of first injection:** Injection tests 2009. Full injection planned for 2015 (now cancelled)
Project scale Small scale (based on actual injection)	**Current status:** Cancelled
Type and depth of reservoir: Sandstones of the Catherine Formation, depth not known	**Type of Seal:** Shales

PROJECT DETAILS

	Project operator	ZeroGen	**Project contact phone**	+61 (0) 405 228 825
	Project contact	Andrew Garnett	**Project contact email**	a.garnett@uq.edu.au
	Project location	Queensland, Australia. Plant – Ensham Storage (failed) Exploration – Northern Denison Trough	**CO_2 source**	Source for test: Food grade CO_2 from BOC. Source for project: Coal IGCC
	Injection site coordinates	23°20'53"S, 150°31'10"E	**CO_2 transport/delivery**	CO_2 trucked for small injection test. Full project development plan was pipeline
	Project planning start	2006	**Injection rate**	150 tpd
	Duration of injection	~2 days	**Injection pressure**	Not known
	Planned injection volume	60,000,000 tonnes	**Total volume injected**	400 tonnes (test)
	Reservoir porosity	5-16%	**Reservoir permeability**	1. Core-derived, over-burden corrected, brine perms 10-100mD 2. Test derived brine perms 0-10 mD
MONITORING	**Seismic monitoring**	4D VSP	**Gravity studies**	Not performed
	Water monitoring	Compositions in nearby shallow water bores	**Pressure logging**	FBHP & FWHP measurements continuously throughout tests
	Soil monitoring	Not performed	**Thermal logging**	DTS
	Atmospheric monitoring	Not performed	**Wireline logging**	Standard before & after reservoir suites included RST
	Ecological monitoring	Not performed	**Observation well**	No observation well
	Tracer analysis	Not performed	**Geochemical research/Fluid sampling**	Extensive geochemical research and water sampling including tests for TPC, total and dissolved metals, dissolved mercury, sodium absorption ratio, pH, dissolved oxygen & BOD
	Electromagnetic	Not performed	**InSAR**	Not performed
RESERVOIR STUDIES	**Reservoir modelling**	Eclipse & CMG-GEMS	**Geologic model**	Petrel
	Coring	7000m of cores (12 wells)	**Seismic**	2D reprocessing, 2D test line
	Other technologies	Modern analogues. Global analogues		

Project context

The ZeroGen project was a Queensland Government Initiative to develop, construct and operate an Integrated Gassification Combined Cycle (IGCC) carbon dioxide capture and storage power plant in Central Queensland. The project was initiated as an action working towards the Queensland Governments ClimateSmart 2050 strategy, relying on clean coal past 2020 and generation of low emission baseload electricity. Initially incorporated by the Stanwell Corporation ltd, a Government owned Queensland power company in 2006, the project was transferred to the Queensland Government in 2007. From 2008 to 2010 an extensive prefeasibility study was undertaken with over $25 million spent on engineering studies. By the end of the study in mid 2012, over $130 million had been spent on storage exploration and appraisal in the Northern Denison Trough. This included 12 wells, 5 of which were injection tested, 4 with water and one (ZG-11) with both water and CO_2 to provide a calibration set. Following final cost estimations and a large gap in project financing, it was recommended that the project not continue – it was subsequently cancelled in Q3 2010.

The project had previously been short listed as part of the Australian Government CCS flagship Program, working towards regional and national emissions targets set for Australia.

Aims of the project

The aim of the storage exploration component (including injection testing) of the ZeroGen project was to inform three **Decision Tests,** which had to be passed before moving into the next phase i.e. into the Engineering Feasibility and further storage appraisal phases. Additional confidence limits were defined, which were ultimately to be achieved after FID.

- To give a very high level of confidence that at least 60 million tonnes could be contained indefinitely within the lease and beneath the cap-rock.
- To provide at least a P50 level of confidence (P75 to be before FID) that an injection rate of at least 2 million tpa could be injected for 30 years.
- To provide at least a P50 level of confidence (P75 to be before FID) that injection and transport could be delivered for a PV, full life-cycle cost of < A$50/t

The IGCC plant was 530 MW (gross), 390MWe with capture targets of 65% (2 million tpa) and optional scope to increase to 3 million tpa after initial development.

Ownership and liability

The project was owned by the Queensland Government through its ownership of ZeroGen. This ownership was effected through the government holding 100% equity in a standard private limited company incorporated under the Corporations Act. The company was run by an independent board of directors and independent executives. Queensland government funds were provided subject to a Shareholder Agreement. The project was co-funded by Australian Coal Association Low Emissions (ACALET) Pty Ltd and the Australian, Department of resources Energy and Tourism (DRET), both under grant (capped) funding agreements. Residual liabilities under this structure would flow back to the Board and ultimately to the State. A licence is required to undertake storage exploration and testing activities. The land on which this took place was privately owned agricultural land. None of the land was subject to Cultural Heritage restrictions. Native Title was not extinguished and Native Title surveys were held at all well sites (with no reported findings).

The company was licensed to undertake drilling under two regimes. Before the passing of the Queensland Greenhouse Gas Storage Act, the first wells were drilled under the Queensland Petroleum and Gas Act. They were situated on a petroleum exploration licence awarded to small oil & gas operating. ZeroGen conducted the work under an agreement with that tenure holder with a subsequent well transfer agreement to transfer title to the wells. The agreement obliged ZeroGen to collect additional data for the tenure holder. The Queensland GHG Act was passed in 2009 and under a special provision, ZeroGen was awarded its active exploration areas as new GHG Exploration Permits. From that date, the company was the tenement holder though operations were managed through a contracted operator, which accepted (capped) operator liabilities under the Act.

The later wells were drilled, and all water and CO_2 injection tests run, within the context of a GHG Exploration Permit awarded by the relevant state department. Within this, the work programs were subject to an Environmental Authority (EA) under the Environmental Protection (EP) Act. These were governed by a different State department. Exploration activities including small scale injection testing were deemed by the State to be *"level 2, non code-compliant, Chapter 5A*" activities under the Queensland EP Act and did not trigger an EIS or the federal EPBC Act. A set of environmental conditions were applied to each activity. These conditions imposed a limit on injection (not storage) testing of 3000 tonnes, the need to meter CO_2 throughout the input supply, the need to measure FBHP & FWHP and the need to monitor nearby water bores in addition to keeping within standard performance limits on noise, dust, air quality and so on. The EA imposed a 1 year post injection monitoring obligation at the site focused mainly on WHP and nearby water bores. Well abandonment schema and remediation plans were discussed in advance with the departments of Natural Resources and Mines (petroleum safety) and Environment. Well completion and abandonment reports had to be submitted along with a final monitoring report, which closed out the EA obligations. Following this 1 year period, the sites were remediated in accordance with standards set by the department of the environment and in accordance with the wishes of the land owners. A statutory tenement submission report was submitted. With the exception of any liabilities at common law, the State's acceptance of these reports marked the end of any liability for the sites.

In the event that a project had gone ahead, long term liability of the storage site was to be governed by the Queensland GHG Act, which includes no fully articulated rules for hand-over of liability. The plan was that this would be dealt with in detail at the next stage as part of the funding and ownership arrangement with the State.

Regulatory and approval conditions

See above for regulatory conditions for storage exploration. Testing was done under these rules and approvals.

The project was declared (with a view to future stages) by the Queensland Coordinator-General as a significant project requiring an EIS under section 26(1) (a) of the *State Development and Public Works Organisation Act 1971* (SDPWO Act).

The project would have constituted a controlled action pursuant to the *Environment Protection and Biodiversity Conservation Act 1999* (EPBC Act) as determined by the Federal Government and it was to be assessed under joint agreement by the Australian and Queensland governments (Ashworth, Rodriguez, Miller, 2010).

Pre-injection geological database and site characterisation

The project was the subject of extensive geological modelling from its initial planning stages in 2003, through an extensive drilling program of 12 coreholes and other exploratory work to the final decision by the Government to scrap the planned IGCC in 2010. As a result of the exploration program the Northern Denison Trough, which was the focal point for storage investigations, was assessed as not being able to sustain the required injection rates required for such project. Furthermore, the maximum rates which were achievable could not be delivered within unit costs hurdle rates set by the project.

The exploration program included the drilling of 12 stratigraphic wells with extensive coring, five of which were tested to appraise the reservoir properties and the connectivity of the flow units. 5 water injection tests and three CO_2 injection tests were conducted as part of this project. While environment authority allowed for up to 3000 tonnes, a total of less than 400 tonnes was injected due to significantly higher than expected pressure build up rates. Details of well tests and test designs are discussed in Kumar et al, 2010 (SPE-139562-MS).

Core from the stratigraphic holes were extensively tested for geomechanical and reservoir properties. These cores along with extended leak-off tests confirmed that containment of injected volumes would be very secure, with very tight cap-rocks, very high fracture gradients and limited lateral migration.

The program also included the acquisition of a 2D seismic survey and an experimental VSP which showed some, unexpected time-lapse response to the injection of 400 t of CO_2 (see Dahlhaus et al, 2012, ASEG).

Source of CO_2

The CO_2 used in the test injection was food-grade CO_2, purchased from a commercial source.

Transport of CO_2

For the field test injection CO_2 was transported by truck; however, for the cancelled full scale project, pipeline was planned.

Additional project details

The project had several phases of development, each with decision points between them: the pre-feasibility study, feasibility study (with FEED) to FID; which would be followed by detailed design, construction and commissioning. Upon construction, the plant was expected to generate 390 MWe of low emission base-load electricity for the Australian energy market. The project was cancelled in Q3, 2010 prior to Feasibility stage execution and operation stages of the large scale component, and after site characterisation pipeline corridor and field test injection had all been carried out.

Stakeholder engagement

Stakeholder engagement filled a key role and was a priority for ZeroGen. A detailed case study report by CSIRO discusses their insights into the stakeholder perceptions of past and present communication and engagement practices conducted by ZeroGen (Ashworth, Rodriguez, Miller, 2010).

The projects stakeholder engagement strategies and communication practices included:

- High-end discussions with key decision-makers using PowerPoint presentation and the project proposal. This information was delivered via fact sheets, website, face-to-face meetings, public conferences, industry groups and national and international conferences, and included as part of ZeroGen's education and communications program.
- Community engagement workshop conducted by CSIRO, factual information was provided on the science of climate change and the broad portfolio of alternatives for low emission energy generation, including CCS. A second workshop, scheduled six months after the initial session, used a participatory action research approach so participants could set the agenda.
- Local stakeholder were engaged via individual meetings or public forums such as community liaison meetings and community meetings taking the form of informational sessions with a project overview; providing details about ZeroGen, its partners in the project, fast facts, the project aims and anticipated benefits the project would bring to stakeholders.
- Physical examples such as drill samples and examples of the technology and its processes were set up on tables at meetings as a form of education interaction.
- At Public meetings different media were used to present information including posters, brochures and fact sheets.
- Public meetings in multiple locations (Emerald, Blackwater and Springsure) were convened at times that were suitable with local landowners who were contacted via open invitation through the post and via public notices in the local newspaper. Presentations were given and open question and answer sessions conducted.
- The ZeroGen website also hosts a Frequently Asked Questions page, which addresses more commonly posed questions surrounding the project and the technology that supports it.

Stakeholder engagement had some significant successes within the project particularly in regards to responding to complaints, overcoming communication barriers with landowners, and finding alternative options such as engaging landowners in work on their land that they're capable of and that would otherwise be carried out by contractors.

Post-project closure discussions with local stakeholders in the areas of operation, revealed that despite extensive community engagement and despite being only at prefeasibility and exploration stages, expectations had been high that a project would ensue. Consequently, there was some local reaction to a perceived "loss of jobs" when the project did not proceed to the next phases. Since the majority of large projects do not make it to FID, expectation management and communication of uncertainty and conditionality in the early days is essential.

Similarly, with respect to government and media stakeholders, the expectation of project continuation seemed to be unrealistically high despite the degree of communication on the stage of the project and relative development and financing risks involved.

Risk assessment process

Venture and project risk management was conducted in line with ISO 31000 standards. An outline of some key issues is included in Garnett et al 2010 (a GHGT-10 conference paper). Risk management in the context of project phases and milestones is also discussed in Kvein et al, 2010 (a GHGT-10 conference paper).

Storage site risk assessments were initially carried out using the URS RISQUE modelling tool. However, this was replaced with an Evidence Based Logic approach in order to more clearly separate risk from uncertainty (see. James et al, 2010. SPE 137447). EBL requires that a hypothesis is formed about how a site is forecast to perform, this is then broken down into sub-hypotheses (containment, injectivity, cost etc) and these sub-hypotheses broken down further to specific tests, which provide supporting evidence (or not). Assessment of risk (evidence in support or evidence against) is compared with uncertainty (no evidence) and the assessment rolled up to make a final assessment. This method avoids problems with weighting of potential "killer" evidence though use of propagation rules. The methodology is described in full at http://www.quintessa-online.com/TESLA/.

Uncertainty management in an alternative, pre-tenement award area is discussed in several GHGT-11 papers (Hurter et al, 2012 and Garnett et al 2012) and in Hodgkinson et al, 2012 (a paper at the East Australian Basins Symposium)

Storage risk and uncertainty assessment was a continuous process throughout the site exploration and appraisal process.

Significant lessons from the project

- The key stakeholders at the beginning of the storage exploration processes are the local land-holders and communities. Education in CCS is important; however, at this stage expectations have to be managed, as the intent is not yet "to store" or to build a project, but only "to assess suitability or otherwise".
- The search for storage is a natural resource exploration and requires a risk-balanced portfolio of "prospects". Significant

data gathering is needed (see below) and project cost forecasts should include an element of "failure" cost.

- When setting storage requirements for a project, it is essential to discuss the consequences and trade-offs between injection rate and cumulative volume objectives. Sites constraints are predominantly related to rate.
- It is essential to articulate the required storage performance and confidence parameters (decision tests) to be achieved before moving to further investments elsewhere in the project.
- Since sites tend to be unique and each would likely need its own appraisal program, it may be economically most attractive to appraise only those sites with large contiguous areas, i.e. sites that can be expanded to fulfil the needs of larger pilots and other projects. Boutique sites will lead to very high finding and appraising costs.
- Estimations of "capacity" made using corrected pore volume (e.g. storage efficiency factor) methods are very poor indicators of site suitability. Dynamic considerations are paramount as the exercise is one of rate-matching with a generating plant.
- Once containment is established with confidence (e.g. XLOT and cap-rock core), it is essential to obtain long term dynamic testing information to appraise the pressure response of the system. A larger number of "cheaper" stratigraphic coring wells does not represent better value of information and is likely to increases overall exploration costs. While relatively expensive on a single well basis, the early acquisition of long term dynamic test data is essential to keeping overall finding costs low.
- For dynamic testing, it is not necessary to inject CO_2 in the first instance. CO_2 injectivity can be estimated from water injection/production and lab results. The economically (and containment) critical parameter to appraise is the rate of pressure build up so that this can be incorporated in predictive models. Furthermore, to detect the impact of heterogeneity, boundaries and baffles, CO_2 injection is not appropriate, water production or injection testing is essential. The duration of tests required depends on the radius of investigation, which is significant well count and field development confidence.
- If a CO_2 test is deemed necessary, it is essential to articulate and define the aims of a test i.e. whether injection or storage or monitoring, or some combination of the three. An injection test may be legitimately required to re-produce (and hence vent) a significant proportion of any injected material. Injection testing and storage may be governed by different licence requirements.
- Contingency plans prior to the end of each stage gate are required, which allow for the event that a project is halted. These plans should define resources required for the documentation and dissemination of lessons learned.

Appendices

Developing a small scale CO_2 test injection: Experience to date and best practice

Peter Cook, Rick Causebrook, Karsten Michael and Max Watson

April 2013

CO2CRC Report No: RPT13-4294

for

IEA Environmental Projects Ltd.

IEA Greenhouse Gas R&D Programme

Stoke Orchard. Cheltenham

FINAL DRAFT

Appendix 3–Bibliography of small scale projects

The following list of related publications have been tagged with unique identifiers to indicate the project or projects that each article relates to, these codes can be found next to the related projects in appendix 1. In some cases, such as the NETL Atlas, these relate to multiple projects that have been combined into the one identifying code. The codes are as follows:

All MGSC Small Scale Projects	N48
All MRCSP Small Scale Projects	N49
All SECARB Small Scale Projects	N50
All WESTCARB Small Scale Projects	N51

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Appendices

Developing a small scale CO_2 test injection: Experience to date and best practice

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for

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FINAL DRAFT

CO2CRC Technologies

Appendix 4 –Summary of some parameters and features for large scale projects

Detailed summaries of large scale injection projects are provided in the MS excel format, please see attached.

Parameters provided in the summary database for large scale projects.	
Project Name	Cost Currency coverted USD
REF #	Seismic monitoring
Type	Water monitoring
Project Scale	Soil Monitoring
Project owner	Atmospheric monitoring
Project operator	Tracer analysis
Prime Contact	Electromagnetic
Title	Gravity studies
Phone	Pressure logging
Email	Thermal logging
Project Location	Wireline logging
Country	Observation well?
Coordinates	Geochemical research/Fluid sampling
Current status	InSAR
Project planning start	Other monitoring technolgoies
Year of first injection	Reservoir modelling
Storage Target	Coring
CO2 Source	Seismic
CO2 transport/delivery	Logging
Total Injection (tonnes)	Geologic model
Injection rate	Reservoir
Injection Pressure (psi)	Project Website
Injection depth	
Total cost of project	