ATTACHMENT D: GEOLOGICAL STORAGE

MATURITY OF GEOSCIENCE TECHNOLOGY

Along with all other science disciplines the knowledge, information and understanding of geology and geophysics as a science has undergone a revolution in the last 50 years due to computing and electronics advancements. These innovations have meant that the traditional geoscience investigations comprising detailed field work measurement and observations of rock outcrops at the surface are now usually extended with accurate measurements for many kilometres into the deep crust of the earth, both by remote sensing methods (geophysical techniques) and direct measurements (drilling). Many modern techniques and engineering advancements allow for “real time” measurements of deep subsurface level conditions, including both the actual rocks (minerals) and the fluids (oil, gas and water) that occur within the pore spaces of the rocks.

This advancement in the obtaining of geoscience subsurface measurements and understanding of the subsurface processes has been largely motivated by economic considerations derived from industries such as oil and gas exploration and production. The engineering and drilling technologies for reaching the deep geological subsurface are extremely sophisticated and not only measure what rocks and fluids are being encountered in an exploration sense as the drill encounters new rock sequences, but also measures in real time ahead of the drilling bit to assess what is about to be encountered. It is common for drilling of the geological subsurface to reach depths of four and five kilometres into the subsurface and then be able to extract fluids for commercial benefit.

During oil and gas production operations, it has been common for many decades to inject fluids (water and gas) to help maintain the pressure in the deep subsurface geological reservoirs and as such enhance oil and gas production rates and commercial return. Typically, only about 30 to 40% of the oil in a reservoir is recovered without such processes. Such activities occur in both the onshore and offshore environments, with offshore drilling now routinely occurring in several kilometres of water depth if required. In addition, it is common throughout the world to inject gas (methane) for storage purposes, either in depleted oil or gas fields, or in aquifers, for later recovery at a time of increased gas demand. An example of this is occurring at the Iona field at Port Campbell in Western Victoria. Understanding of the geological processes and predictions of the types of rocks and their attributes is also a highly advanced science. It is common for geophysical surveys to be acquired that map the geological subsurface in four dimensions (three dimensional space and the fourth dimension of time) which allows oil and gas companies to map and monitor the extent of geological subsurface reservoirs and the fluids that are contained within them, both before, during and after production. As oil and gas fields are produced and eventually depleted, the movement of fluids and the impact that this has on the immediate and surrounding geological layers (called formations) is monitored as part of normal operations for an oil and gas producing company, and occurs at many thousands of sites around the world.

In the groundwater industry, tens of thousands of relatively shallow wells have been drilled within Australia to intersect, produce and understand subsurface groundwater movement. This knowledge and information allow hydrogeologists (groundwater specialists) to predict pressure and water movement in the shallow aquifer systems, and accurately predict for most sedimentary basins at what depths potable versus saline water resources exist. Whilst groundwater operations are very much shallower than the levels at which geological storage of CO_2 will take place, the principles and knowledge is very relevant. Importantly, it allows reliable assessments to be made of what might happen were CO_2 to unexpectedly migrate up into the shallow subsurface from the deeper targeted geological formations where CO_2 injection and storage is likely to take place.

There is also a small but important industry of carbon dioxide production from natural accumulations of carbon dioxide in subsurface accumulations. This occurs in the Otway Basin of South Australia and Victoria (the Caroline and Boggy Creek fields). The Caroline field has been in production since 1967 and the CO_2 is used in the food and beverage industry. In the United States there is extensive interstate transport of carbon dioxide from naturally occurring CO_2 fields in New Mexico to Texas for the purposes of enhanced oil recovery (see page 9 on **Geological Storage Concepts – Enhanced Oil Recovery**).

Thus the many technologies, information and techniques developed for oil and gas exploration and production, gas storage and carbon dioxide and groundwater extraction are immediately transferable to the geoscience aspects of CCS. It is for this reason that scientists and engineers are confident with the ability to undertake the necessary assessments and operations associated with injection and storage of CO_2 into the deep geological subsurface, and to accurately assess any potential impact that may occur and to monitor its subsequent behaviour.

There will be circumstances where CCS activities will have unexpected benefits due to the knowledge and implementation of the technology. In some sedimentary basins in Australia which have been heavily utilised for groundwater production, the concomitant drop in aquifer (reservoir) pressure and increasing depth at which potable water exists is becoming an increasing concern as it diminishes the resource and increases cost to access it. Similar reservoir pressure reductions are occurring in some of Australia’s premier oil and gas producing basins, resulting in decreased production and in some instances a loss of hydrocarbon resource. It has been suggested that with large scale injection of CO_2 into the deep geological subsurface into saline reservoirs, it is entirely possible that where there is pressure communication within a sedimentary basin, some of these pressure reductions might be reversed, with positive benefits to oil, gas and water resource production and reduction in costs.

GEOLOGICAL STORAGE PRINCIPLES

Sedimentary Basins

Large scale geological storage of CO_2 will occur in sedimentary basins. **Sedimentary basins** are large depressions in the earth crust which form from earth forces such as plate tectonic and deep crustal movement. Over geological time sediments are transported into sedimentary basins by river systems, marine currents and wind. They eventually accumulate into thick deposits, often 10s of kilometres thick. As more sediment accumulates, the weight of the overlying sediment further depresses the sedimentary basin, creating more space for sediment to accumulate as subsidence continues. Sediments comprising sand, silt, clay, organic matter, lime and salt are the common components of the main sedimentary rock types (sandstone, siltstone, shale, coal, limestone, dolomite, anhydrite and halite) that form in sedimentary basins, and which are important for storage of CO_2.

Reservoirs and Seals

Geological storage **reservoirs** will comprise rock types that have both **porosity** (measurement of the void space in a rock – normally between small grains of sand) and **permeability** (measurement of a rock's ability to transmit fluids via interconnected pore space or fractures) such that the CO_2 can be injected and then can move through the rock away from the well injection point into the storage reservoir. These geological storage reservoirs will normally be rock types such as sandstone, siltstone and limestone. Overlying and flanking the storage reservoirs will be **seals** (cap rocks) that are generally fine grained rocks that have low or no permeability and thus will prevent or inhibit the migration of the injected CO_2 out of the storage reservoir. Seals generally comprise rock types such as shale, anhydrite and halite. The arrangements of seals overlying reservoirs are often termed reservoir-seal pairs, and they act to trap fluids in rocks from migrating to the surface. Generally before trapping can occur, the geological formations of shale (seal) and sand (reservoir) need to be deformed through earth movements into folds (**anticlines**). This occurs naturally over geological time (millions of years) as the sedimentary basin subsides, and develops further through collisions of tectonic plates which uplift and depress sedimentary basins, often forming mountain ranges and large geomorphological features (e.g. continental shelves) composed of thick regions of sedimentary rocks.

Fluids in the deep subsurface

Fluids occur and are trapped in the pores in rocks in all sedimentary basins at both shallow and deep levels (up to 10s km). These fluids comprise fresh water in the shallow geological sections (usually < 1 km) and predominantly saline water in the deeper geological sections (usually > 1 km but can often be much shallower). Very rarely when the correct geological conditions exist, the fluids include hydrocarbons in the form of oil and gas accumulations. Quite often the fluids include naturally formed CO_2 that has co-generated with the hydrocarbons in a thermal maturation process of heating of organic rich and/or carbonate rich rocks, or has been sourced from deep crustal process such as volcanic activity. Without effective seals, all fluids in the subsurface that are under pressure would eventually migrate their way to the surface, as fluids are less dense than sediments and rocks and through buoyancy forces will move to the surface unless impeded due to permeability flow barriers such as seals. An example of where large volumes of hydrocarbons occur at the surface after long distance migration to the edges of a sedimentary basin are some of the extensive tar sands accumulations of the world.

Outcrops of permeable rocks in mountain ranges can sometimes act as recharge zones for deep fluid filled reservoirs in sedimentary basins. When rainfall occurs in mountain ranges, the fresh water from the rainfall can enter the deeper geological formations via the permeable zones in the porous sedimentary rocks, and flow down into the geological formations within the sedimentary basin. Such recharge and movement of fluids in the deep geological subsurface occurs over geological time, and is normally measured in millimetres per thousand years. Fluids are trapped within the sediments (clay, silt, lime and sand) that are deposited within sedimentary basins. These sediments and the trapped fluids are gradually buried by deposition of overlying layers of sediment, with the sediments of clay and sand gradually transforming into rocks (shale and sandstone) due to the heat and pressure increases that occur in the deep earths crust. The fluids in the deep geological subsurface are generally under high pressure and temperatures due to the weight of the overburden of rocks and fluids pressing down on them and the heat generated from within the crust. The fluids within the deep geological subsurface have been formed and trapped over millions of years, and represent important analogues for CO_2 storage technology.

The variety of fluids in the subsurface have a range of different chemical and physical properties such as density, solubility, and mobility (Table A). Where more than one fluid is present in a reservoir, complex relationships exist as to how they react and respond in terms of transport or chemical processes. For instance CO_2 will dissolve more readily into less saline water, and when dissolved into water the CO_2 saturated water is denser than the surrounding water so will migrate down through the reservoir towards the centre of the basin, overcoming buoyancy forces. This last research outcome has been described by the CSIRO[1], and has profound impact on the potential of storing large volumes of CO_2 in deep saline reservoirs through dissolution trapping mechanisms.

Table A: Properties for carbon dioxide under various stages of compression[2].

Properties of gaseous, supercritical and liquid CO_2

Properties	Gas	Supercritical	Liquid
Density (g/cm^3)	~0.001	0.2–1.0	0.6–1.6
Diffusivity (cm^2/s)	0.1	0.001	0.00001
Viscosity (g/(cm s))	0.0001	0.001	0.01

CO_2 critical parameters: $T_c = 31.1$ °C; $P_c = 7.38$ MPa; $\rho_c = 0.47$ g/cm^3.

Retention time of fluids in the subsurface

Thousands of millions of barrels of oil and gas and co-generated CO_2 have been formed and trapped in the deep geological subsurface both within Australia and the

[1] Role of convective mixing in the long-term storage of carbon dioxide in deep saline formations. Ennis-King, J.E. and Paterson, L., 2005: Society of Petroleum Engineers Journal September 2005 pp 349-356.

[2] Zhang, ZX, Wang GX, Massarotto P and Rudolph V, 2006 . *Energy Conversion and Management* 47, 702-715. Elsevier and www.sciencedirect.com.

other sedimentary basins of the world[3]. In Australia the times over which such natural trapping of hydrocarbons and CO_2 has been formed and trapped ranges from 10s to 100s of millions of years, with some minor accumulations having been trapped for billions of years in the deep geological subsurface. Through exploration for oil and gas in Australia, over 500 million tonnes of naturally occurring CO_2 has been unintentionally discovered in the deep geological subsurface in geological traps associated with hydrocarbons. To form and trap hydrocarbons in the deep geological subsurface requires the natural occurrence and correct timing of numerous factors such as deposition of an effective organic rich source rock (coal or shale), deposition in the correct order of seals and reservoirs, earth movements to generate geological traps (anticlines) within the reservoir-seal pairs, heating of the organic source rock to temperatures that expel hydrocarbons, migration of those hydrocarbons along permeability pathways into geological traps, and preservation of those traps and the trapped fluids for 10s of millions of years and longer. It is this analogy with natural trapping of large volumes of fluids for geological time periods in the deep geological subsurface that gives significant confidence to the technical opinion that large volumes of anthropogenically derived CO_2 can be geologically stored.

It is important to note that the injection and storage of CO_2 into the deep geological subsurface does not depend upon the vagaries and natural occurrence of geological processes and events with the correct order and timing that is required for hydrocarbon formation, generation and trapping. It is this unique arrangement of relative timing and the vagaries of geological processes that makes exploration for and finding of oil and gas accumulations a risky business, with finding success rates of 1 in 10 being commonplace. However for geological storage of CO_2, the requisite reservoirs, seals and traps can be actively explored for, found, examined and rigorously tested before a site is chosen for injection and geological storage.

Injection of Fluids

The general principle associated with the injection of CO_2 into geological formations in sedimentary basins is to pump CO_2 into the deep subsurface (generally over 800m) via well bores that have been drilled specifically for that purpose. Injection is normally anticipated to occur below depths of 800m, as at that depth and pressure the CO_2 will be in a **supercritical phase** where it will be very much denser than at surface conditions, and will have properties between those of gases and liquids. Being much denser in the subsurface means that a very much smaller volume will be occupied by the CO_2 than it would have been at the surface or atmospheric conditions. Injection wells can be drilled to intersect a specific target formation which can be identified and correlated from neighbouring well bores, outcrop geology, or geophysical seismic data. The injection well will be lined with steel casing which is cemented into the formation, then perforated (making of holes through the casing) at the appropriate intervals into adjacent storage formations (reservoirs).

[3] Storage Retention Time of CO_2 in Sedimentary Basins: Examples from Petroleum Systems. Bradshaw, J., Boreham, C., la Pedalina F., 2004 - Proceedings of the 7th International Conference on Greenhouse Gas Control Technologies, September 2004, Vancouver, Canada. (http://uregina.ca/ghgt7/PDF/papers/peer/427.pdf)

When intersected during the drilling of bore holes (wells), high pressures in deep subsurface reservoirs are potentially provided with a connection to the much lower surface pressure conditions. Because of the pressure difference between the surface and deep subsurface, fluids could flow to the top of the well bore. To prevent this happening during oil and gas exploration drilling, pressure is maintained in the annulus of the well bore through the use of “heavy” mud, which regulates and matches the pressure in the well bore from the fluids trapped in the sedimentary rocks. This thus prevents highly pressured deep subsurface fluids flowing to the surface via the well bore. To achieve injection of fluids into the deep geological subsurface, the deep subsurface pressures must be overcome, and there must be a porous and permeable rock into which the injection can be targeted. A higher pressure must be created through compressors at the surface to overcome the pressure in the deep subsurface at the perforation interval of the storage reservoir. Compressed fluid can then be transported down the well bore and will enter into the targeted reservoir. It is through this method that CO_2 can be injected into deep geological formations. For large volumes of CO_2 to be injected over a long period of time, adequate sedimentary rock types, geological traps, geomechanical factors and reservoir injection conditions must exist.

Scale of Injection Required

For geological storage to make a significant difference in emission reductions, it will be necessary store substantial volumes of CO_2 into the deep geological subsurface. To grasp the magnitude of the undertaking it is worthy to compare what a CO_2 injection and storage industry would need to look like compared to the existing world natural gas production industry. The rates of production of gas can be compared to the likely injection rates of CO_2 that might be achievable into a reservoir. In the gas industry, a large gas field is commonly recognised as being of a size of about 1 trillion cubic feet (TCF), and may produce gas over a 20 to 30 year period from perhaps 15 to 20 wells.

Currently, measured in TCF, Australia emits approximately 5 TCF of $CO_{2\ eq}$ per year from coal fired power stations, the USA about 40 TCF $CO_{2\ eq}$, and the world’s total emissions from all sources are about 450 TCF $CO_{2\ eq}$. This compares with gas (methane) production rates for Australia of 1.3 TCF / yr, for USA of 22.3 TCF / yr, and for the world of 100 TCF / yr. Thus it is entirely likely that if the CO_2 injection and storage industry is to be effective in making an impact on CO_2 emissions, it will have to be as large, if not many times larger, than the existing world gas industry.

Trapping Methods in Geological Formations

Trapping and ultimately storage of CO_2 in geological formations in the subsurface can occur through various mechanisms (Table B). These include;

- structural and stratigraphic trapping through buoyancy effects (e.g. anticline) such that the CO_2 migrates into the top of a trap,
- residual gas trapping in the interstices in pores in the rocks where CO_2 remains in the small pores in the rock,
- dissolution into the reservoir fluids (brine),
- mineral precipitation to form new compounds,

- hydrodynamic trapping within the regional groundwater system where movement of the CO_2 is prevented due to pressure forces from groundwater flow, and
- adsorption onto the surface of coal.

The different trapping mechanisms will account for different relative proportions of any storage scenario, and could operate independently, concurrently or exclusively in any storage system. The time for trapping to become effective ranges from instantaneous to tens of thousands of years, and will be dependent on the particular rock and reservoir fluid chemistry and the rate at which CO_2 migrates through the reservoir.

Table B: The different chemical and physical trapping mechanisms by which CO_2 will be stored in the reservoirs in the deep geological subsurface into which it has been injected [4].

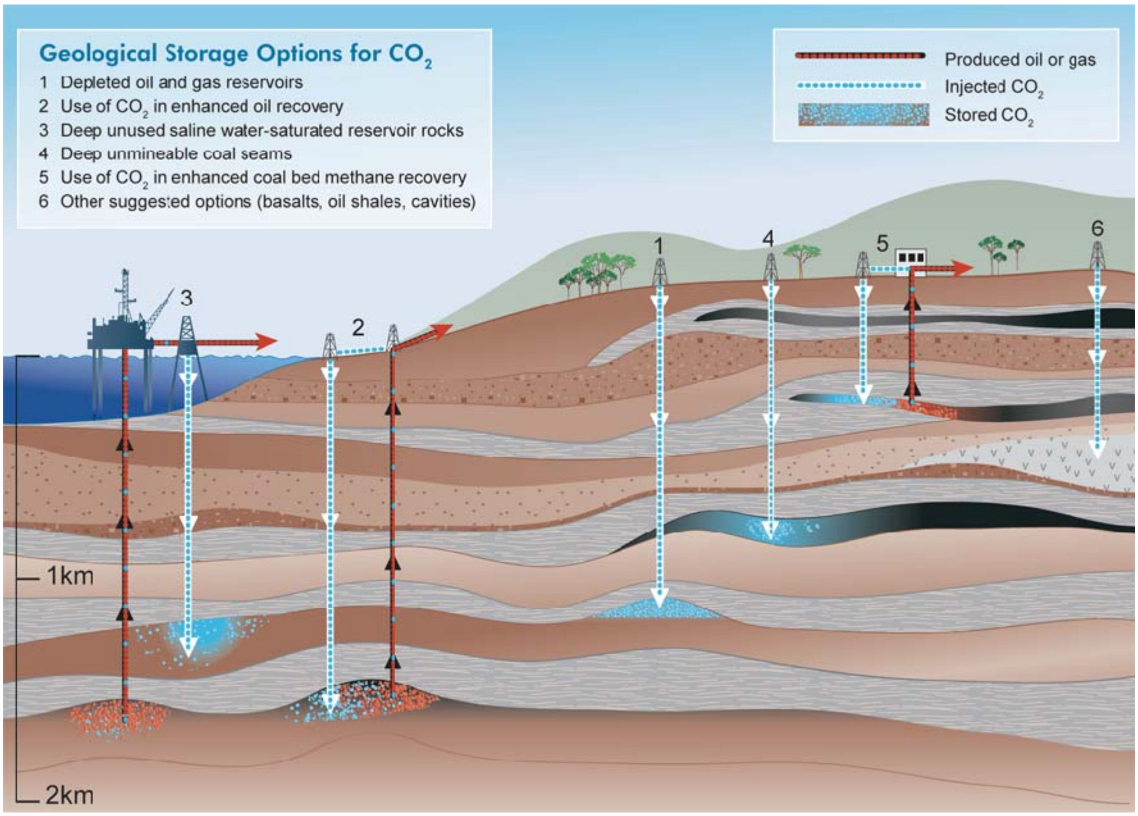
Characteristics / Trapping mechanism	Nature of trapping	Effective time frame	Areal size	Occurrence in basin	Issues	Capacity limitation/ benefits	Potential size	Capacity estimation method/ requirements
Structural & stratigraphic	Bouyancy trapping within anticline, fold, fault block, pinch-out. CO_2 remains as a fluid below physical trap (seal)	Immediate	10s km to 100s km	Dependent on basins tectonic evolution. 100s of small traps to single large traps per basin.	Faults may be sealed or open, dependent on stress regime, fault orientation & faults could be leak/spill points or compartmentalise trap.	If closed hydraulic system then limited by compression of fluid (few %) in reservoir. If open hydraulic system will displace formation fluid.	Significant	Simple volume calculation of available pore space in trap, allowing for factors that inhibit access to all the trap - eg. sweep efficiency, residual water saturation.
Residual gas	CO_2 fills interestices between pores of the grains of the rocks.	Immediate to thousands of years	Basin scale eg. 1000s km	Along migration pathway of CO_2	Will have to displace water in pores Dependent on CO_2 sweeping through reservoir to trap large volumes.	Can equal 15-20% of reservoir volume. Eventually dissolves into formation water.	Very large	Requires rock property data & reservoir simulation.
Dissolution	CO_2 migrates through reservoir beneath seal & eventually dissolves into formation fluid.	100s to 1000s of years if migrating more than 1000s of years if gas cap in structural trap & longer if reservoir is thin & has low permeability.	Basin scale eg. 10000s km	Along migration pathway of CO_2 both up dip & down dip.	Dependent on rate of migration (faster better) & contact with unsaturated water & pre-existing water chemistry (less saline water better) Rate of migrations depends on dip, pressure, injection rate, permeability, fractures, etc.	Once dissolved, CO_2 saturated water may migrate towards the basin centre thus giving the very large capacity. The limitation is contact between CO_2 & water & having highly permeable (vertical) & thick reservoirs.	Very large	Requires reservoir simulation & need to know CO_2 supply ratio & injection rate.
Mineral precipitation	CO_2 reacts with existing rock to form new stable minerals.	10s to 1000s of years.	Basin scale eg. 10000s km	Along migration pathway of CO_2	Dependent on presence of reactive minerals & formation water chemistry. Could precipitate or dissolve.	Rate of reaction slow. Precipitation could 'clog' up pore throats reducing injectivity. Approaches 'permanent' trapping.	Significant	Requires rock mineralogy
Hydrodynamic	CO_2 migrates through reservoir beneath seal, moving with or against the regional ground water flow system whilst other physical & chemical trapping mechanisms operate on the CO_2	Immediate	Basin scale eg. 10000s km	Along migration pathway of CO_2 with or against the direction of the flow system that may move at rates of cm per year.	Dependent on CO_2 migration after the injection period, being so slow that it will not reach the edges of the sedimentary basin where leakage could occur.	No physical trap may exist & thus totally reliant on slow transport mechanism & chemical processes. Can include all other trapping mechanisms along the migration pathway.	Very large	Requires reservoir simulation & regional reservoir flow model.
Coal adsorption	CO_2 preferentially adsorbs onto coal surface.	Immediate	10s km to 100s km	Limited to extent of thick coal seams in basins that are relatively shallow.	Coals can swell reducing injectivity. Difficult to predict permeability trends. CO_2 adsorption not 100% effective which raises issue of leakage if no physical seal is present.	Injectivity poor due to low permeability. Effective at shallower depths than porous sedimentary rocks, but not at deeper depths due to permeability issues. Many injection wells required. If methane liberated might not be net GHG mitigation.	Low	Requires gas sorption data & knowledge of permeability trends & coal 'reactivity' to CO_2 06-166-6

[4] CO_2 Storage Capacity Estimation: Issues and development of standards. Bradshaw, J., Bachu, S., Bonijoly, S., Burruss, R., Holloway, S., Christensen, N.P., Mathiassen, O.M., 2006 - Proceedings of the 8th International Conference on Greenhouse Gas Control Technologies, June 2006, Trondheim, Norway.(https://events.adm.ntnu.no/ei/viewpdf.esp?id=24&file=d%3A%5CAmlink%5CEVENTWIN%5Cdocs%5Cpdf%5C950Final00117%2Epdf)

GEOLOGICAL STORAGE CONCEPTS

The injection and storage of CO_2 into the deep geological subsurface has been suggested to be able to operate across a range of geological formations and concepts. These are shown in Figure A. The main options, ranked in terms of the potential storage volumes that might be able to be stored, include (high to low); deep saline reservoirs (aquifers), depleted gas reservoirs, depleted oil reservoirs, enhanced oil recovery, unmineable coal seams, enhanced coal bed methane. Less likely storage options include basalts and oil shales

Figure A: Options for geological storage of CO_2. Source: Intergovernmental Panel on Climate Change Special Report on Carbon Dioxide Capture and Storage[5].



Deep Saline Reservoirs

Deep saline reservoirs, also known as saline aquifers, are combinations of reservoirs and seals that occur deep within a sedimentary basin and whose fluids in the pores in the rocks are mostly saline water. In terms of potential storage volume, they represent by far the largest opportunity of all the storage concepts. If CCS is going to be deployed at a large scale around the globe and within Australia so as to make a significant impact on CO_2 emission reduction, then saline reservoirs will have to be the dominant storage concept to be deployed. Whilst they have enormous storage

[5] Intergovernmental Panel on Climate Change (IPCC) Special Report on Carbon Dioxide Capture and Storage, Cambridge University Press. Metz B, Davidson O, De Coninck H, Loos M and Meyer L (Eds.) 2005.

capacity, they could suffer from a lack of data in some sedimentary basins where little exploration has occurred. If storage occurs in onshore basins, and sites are not appropriately chosen, then they could present risks of leakage into the groundwater system by migration up dip into shallower geological formations. Trapping can occur physically through structural and stratigraphic traps formed in the rock formations (anticlines), through residual gas trapping and through hydrodynamic trapping, and/or chemically through dissolution of the CO_2 into the formation water in the rocks and mineral precipitation.

Depleted oil and gas reservoirs

Injection into **depleted oil and gas reservoirs** essentially replaces the oil and gas that have already been produced. Trapping will largely be based on structural and stratigraphic traps that the oil and gas accumulations were originally trapped within. Depleted oil and gas reservoirs are often quoted as one of the early opportunities for geological storage of CO_2. However this does not appropriately recognise the time lag that exists between their potential for storage compared to the timing for their availability, or the impact of ongoing economic factors. For example whilst there are 14 Gt CO_2 potential storage capacity in known oil and gas fields in Australia (yet to be depleted), by far the majority of that capacity will not be available until the fields are fully depleted in some 40 years. The added impact of high oil prices means that many apparently “near depleted” fields are now being reactivated because of the more economically favourable conditions for extraction of hydrocarbons, thus delaying even further their potential availability for CO_2 storage. Overall, depleted fields only represent a very small percentage of the *theoretical* capacity available in saline reservoirs. To put depleted fields in context, the potential storage space in the known (including depleted and yet to be depleted) oil and gas fields in the south-east Queensland region (Bowen and Surat Basins) would be filled by a single years CO_2 emissions from that region. Such sites will have large amounts of data available due to the exploration and production for the oil and gas fields, and represent a proven trapping mechanism for fluids. However, being an old hydrocarbon production field will mean that there will be many pre-existing penetrations of the geological formations from old wells that could be potential leakage points if not appropriately remediated, as well as reservoir pressure draw down and potential geomechanical impacts will have to be carefully assessed.

Enhanced Oil Recovery

For four decades, CO_2 has been injected into depleted oil fields to enhance the recovery of the remaining oil in the reservoirs (**EOR**). The CO_2 acts like a solvent and allows the oil to become less viscous and move more freely through the reservoir to the oil production wells. This can enable substantially more oil to be recovered from a field, in some cases doubling the field reserves. CO_2 is normally co-produced with the recovered oil in this process and the CO_2 then is separated and re-injected into the well. This is done because the CO_2 can cost around \$20 to \$30US / tonne to procure, and thus is too valuable to simply vent to the atmosphere. In many Texas EOR operations, the CO_2 is currently sourced from natural geological accumulations from as far away as Colorado, and there are over 2500 km of pipelines in the USA dedicated to CO_2 transport for EOR operations. Not all oil fields are suitable for EOR using CO_2 injection, as it is dependent on the oil type and reservoir conditions.

Clearly EOR operations have a major economic benefit, and such opportunities are already underway and planned for many parts of the world. The cost of pipelines and of procuring large volumes of pure CO_2 is a limiting factor for implementation of EOR. Most EOR operations have a clear economic basis for existing, and there is more focus on maximising the removal of oil than maximising the storage of CO_2. Existing or planned operations might inject CO_2 for 4 or 5 years, and then recycle the injected CO_2 over the planned life of the EOR operations (20 – 30 years). Storage of perhaps 20 Mt CO_2 might be considered as a guide of an average amount for each operation. The trapping mechanism will be essentially identical to depleted oil and gas fields, being based on structural and stratigraphic traps that the oil accumulations were originally trapped within.

The majority of the EOR operations to date have occurred in North America (Texas). Geoscience Australia calculated the theoretical potential for EOR and CO_2 storage in Australia, and determined that at $20 US / barrel, there was the potential to recover another 1.1 billion barrels of oil and to store approximately 600 Gt CO_2[6]. The significant limitation to this occurring immediately in Australia is the ability to source sufficient volumes of pure CO_2 for the technology to be applied, apart from the infrastructure that might be required if sources existed. Statoil (a Norwegian oil company) are drawing up plans to consider building CO_2 sea going tankers that could potentially be used to transport CO_2 to offshore EOR operations in the North Sea, thus avoiding the cost of pipeline infrastructure. A range of reports have been produced in recent times looking at EOR economic opportunities in the North Sea, with some declaring it is not viable, whilst others have suggested it will only be possible with government incentives to help the projects become established.

Coal Seams

Injection of CO_2 into coals seams has been proposed as a potential storage option. It is either proposed to inject CO_2 into **deep unmineable coals seams** or to inject CO_2 into coal seams that contain methane, which will liberate methane, and which then can be used as an energy source (**enhanced coal bed methane**). Injection of CO_2 into coal seams will sterilise them from future exploitation through processes such as underground mining.

There have been a number of pilot projects around the world examining the potential of coal seam injection, and the results have suggested that there are many technical difficulties, such that it is clear that this storage concept will at best only provide a very minor contribution to world storage capacity, and thus may only ever provide some localised “niche” opportunities. Some of the issues documented include; a) as CO_2 is injected into the coals, the coal swells, thereby reducing the potential to continue to inject, b) coals have very poor permeability thus making injection difficult in the first place, c) injection of CO_2 will sterilise the coal from future mining, and thus only deeper unmineable seams can be considered. However, in Australia this means depths of 600m – 1200m will have to be targeted, at which there often is no permeability remaining, thus precluding injection.

[6] CO_2 EOR Storage Potential In Australia. Le Poidevin. S., and Wright, D., 2005.Geoscience Australia Publication Record.

In terms of enhanced coal bed methane, CO_2 injected into the coal seam will preferentially adsorb onto the coal matrix and release methane. Geologically however, coal deposits are not usually associated with laterally continuous geological formations that will form thick overlying regional seals. Thus careful examination of possible sealing features would be required to ensure that there is no risk that methane could be liberated to the surface and atmosphere, as occurs through natural processes in some shallow coal seams. It is important to ensure no leakage of liberated methane, as methane is 21 times worse as a greenhouse gas than CO_2, and thus it would be problematic whether an enhanced coal bed methane site would produce a net greenhouse gas mitigation, especially if a full life cycle analysis of the energy penalties of the operation is taken into consideration along with released methane.

Other Options

A variety of other options have been proposed, such as injection into **basalts** and into **organic rich shales**. They both suffer from having very limited if any permeable sequences within them, thus inhibiting injection rates. Both of these options have had very limited testing, but on basic geological principles are extremely unlikely to represent major areas for storage of any significant volumes of CO_2, even if they are proven to be viable at a local level. A large proportion of India is covered in thick basalt layers, and thus it has been an area that has attracted some research. Whilst the basalts themselves are unlikely to be significant injection targets, the sedimentary basins underlying the thick basalt layers may be of considerable interest. As such, research into the impact of CO_2 on the overlying basalt, what chemical changes could occur, and the seal characteristics the basalt may possess could be areas worthy of ongoing research.

Geological Storage Capacity

Assessments of CO_2 storage capacity can be expressed in terms of the **theoretical, realistic or viable** storage capacity potential[7]. The global *theoretical* storage potential for geological storage of CO_2 is probably many thousands of gigatonnes (Gt) of CO_2. But such an assessment of capacity includes mostly implausible locations and operations without considering any economic or technical barriers. It is also based on almost no actual data from individual sites at any detailed global level. It is thus of very little use in guiding any practical discussion of CO_2 storage implementation.

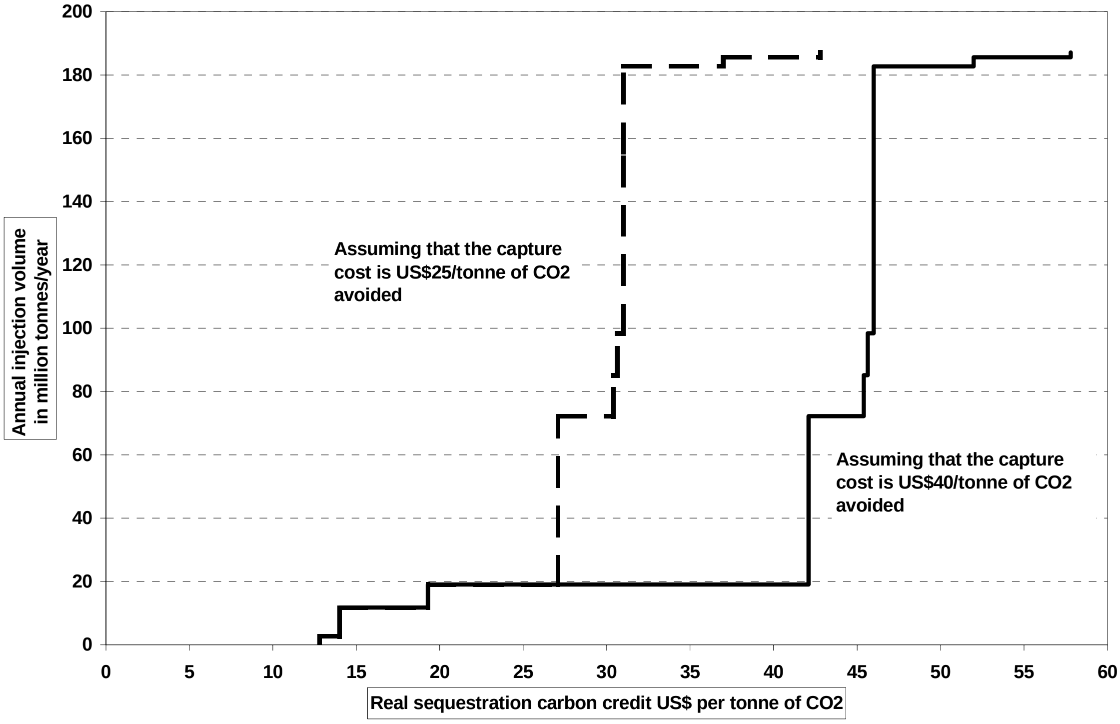
Theoretical storage capacity in Australia was calculated by Geoscience Australia as 740 Gt CO_2 [8], based on specific data from individual sites with a deterministic risk approach to produce a seriatim of potential storage sites. This assessment still suffers

[7] CO_2 Storage Capacity Estimation: Issues and development of standards. Bradshaw, J., Bachu, S., Bonijoly, S., Burruss, R., Holloway, S., Christensen, N.P., Mathiassen, O.M., 2006 - Proceedings of the 8th International Conference on Greenhouse Gas Control Technologies, June 2006, Trondheim, Norway.(https://events.adm.ntnu.no/ei/viewpdf.esp?id=24&file=d%3A%5CAmlink%5CEVENTWIN%5Cdocs%5Cpdf%5C950Final00117%2Epdf)

[8] The potential for geological sequestration of CO_2 in Australia: preliminary findings and implications for new gas field development. Bradshaw, J., Bradshaw, B.E., Allinson, G., Rigg, A.J., Nguyen, V., and Spencer, A., 2002 - APPEA Journal, Vol 42 part 1 p. 25-46.

from no practical reality in terms of implementation due to no significant technical or economic barriers being applied that might prevent a site from being considered feasible. Subsequent analysis based on matching of potential storage sites with nearby CO2 sources and applying some economic and technical cut-offs identifies that Australia has a realistic potential to sustainably store up to 25% of our annual emissions of ~500 Mt CO2/year[9]. Given the large theoretical potential that exists in Australia for storage, opportunities to store large quantities of CO2 will become available as the economics of capture and storage decreases and the costs of emitting CO2 increase. This can also be expressed in Figure B by examination of the cost curve approach where between 20 and 180 Mt CO2/year could be stored depending on the cost of capturing and storing CO2[10].

Figure B: Illustrative economic CO2 storage potential of Australian reservoirs. This diagram shows the volume of CO2 that could be stored for any given level of the carbon credit. Costs of capture of US$25 and US$40 per tonne are assumed. The effects of income tax and any secondary taxes are ignored.



No *viable* storage capacity has been calculated for Australia, but such an assessment could only be done at a site specific level and would entail analysis of detailed data sets that have yet to be obtained and experience yet to be gained from operational large scale injection projects.

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[9] Australia's CO2 geological storage potential and matching of emission sources to potential sinks. Bradshaw, J., Allinson, G., Bradshaw, B.E., Nguyen, V., Rigg, A.J., Spencer, L. and Wilson, P. 2004 - Energy Journal Volume 29, Issue 8.

[10] The Economics of Geological Storage of CO2 in Australia.. Allinson W.G., Nguyen D.N., and Bradshaw J, 2003. *The APPEA Journal* 43(1), 623-636.

Source Sink Matching

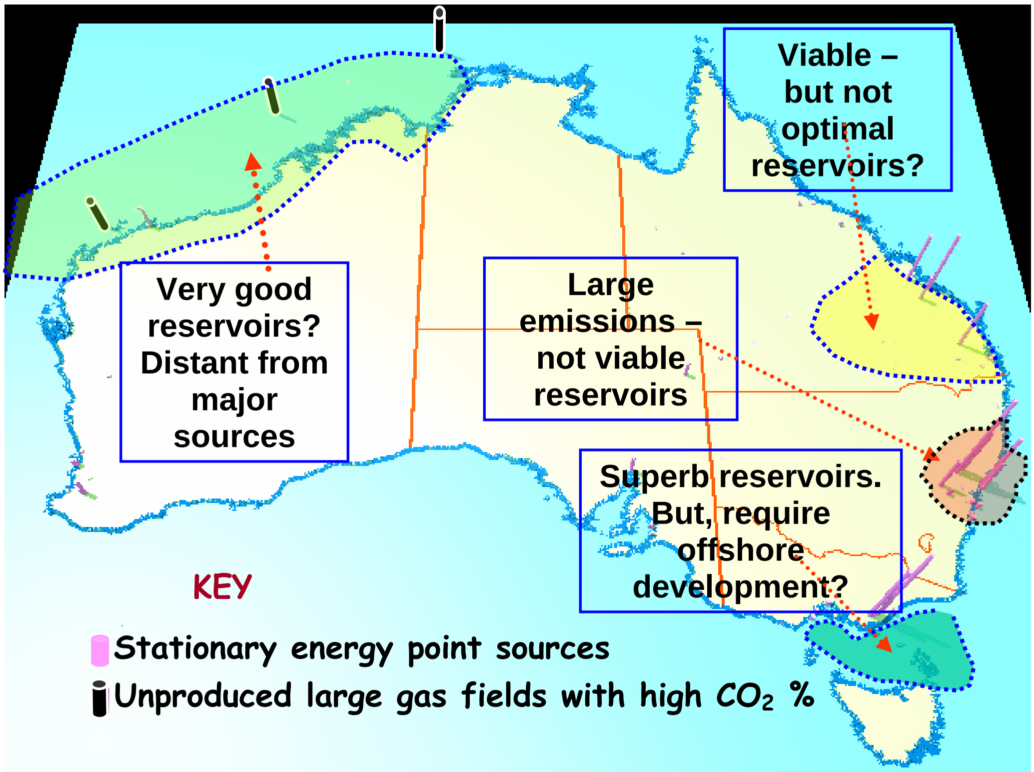
An important aspect of how and where CO_2 injection and storage could potentially be implemented as an industry, relates to how well geographically and economically the options for storage locations and emission locations can be matched. Figure C shows the relationship that exists in Australia between large stationary energy emission point sources and the geological characteristics of the neighbouring sedimentary basins and potential storage reservoirs. It is from this source sink matching, that the *realistic* storage capacity values (described above) have been calculated[11]. Excellent reservoirs exist in Australia's sedimentary basins that are major petroleum basins such as the North West Shelf in Western Australia and the Offshore Gippsland basin in southeast Victoria, whereas only marginal reservoirs exist in southeast Queensland in the Bowen Basin and non-viable reservoirs occur in the Sydney region in the Sydney Basin.

By comparison, the major emissions sources (power plants) for Australia are located within the major coal provinces, which occur in the eastern Australian sedimentary basins. Whilst the offshore Gippsland Basin has excellent reservoirs and is immediately adjacent to the potential major emissions from the brown coal sources in the Latrobe Valley (11% of Australia's total emissions), it will require significant capital investment to establish infrastructure and pipe CO_2 into an offshore environment. Similarly whilst the North West Shelf has very good reservoirs, it is very distant from the largest emission sources which are on the east coast. The North West Shelf will however provide many opportunities for the potential emissions from the high CO_2 gas fields located in the Carnarvon and Browse Basins (potentially equivalent to 4% of Australia's total annual emissions). In southeast Queensland in the Bowen Basin the reservoirs are marginal due to low permeability, but the sources (9% of Australia's total annual emissions) are within 250 km of potential storage sites and they are both in an onshore environment. In the Sydney Basin region, despite having large emission sources (15% of Australia total annual emissions), the geological characteristics of the reservoirs (no permeability) precludes any significant likelihood of large scale injection or storage of CO_2.

It is possible that if a very good storage site exists that can take large volumes of CO_2 at very high injection rates, but it is at a greater distance from large emission sources than a number of smaller less high quality and disparately located injection sites, then a large pipeline with high volumes of CO_2 could mean that economies of scale could make the bigger more distant site more viable. As an example, the very high quality of the reservoirs in the offshore Gippsland Basin, the pre-existence of a pipeline route from the Gippsland Basin to Sydney, and the potential to build a very large pipeline carrying CO_2 from all the Sydney region power stations to the Gippsland Basin, means that with economies of scale, long pipelines with large volumes and very good storage sites might prove to be a feasible option.

[11] The potential for geological sequestration of CO_2 in Australia: preliminary findings and implications for new gas field development. Bradshaw, J., Bradshaw, B.E., Allinson, G., Rigg, A.J., Nguyen, V., and Spencer, A., 2002 - APPEA Journal, Vol 42 part 1 p. 25-46.

Figure C: Comparison of the major stationary energy CO_2 emission sources in Australia with the characteristics of the sedimentary basins and potential storage reservoirs in the adjacent regions[12].



Planned or existing CCS operations

A range of projects are being planned or underway at the pilot, demonstration or commercial scale for CCS, many of which can be found on the Carbon Sequestration Leadership Forum (CSLF) website as being recognised projects under the CSLF (http://www.cslforum.org/projects.htm). These projects range from geological storage and injection to capture to monitoring and verification activities. The International Energy Agency (IEA) also list a vast array of projects being planned or underway for CCS on their website (http://www.co2captureandstorage.info./).

Existing "Industrial" CCS operations

There are only a few areas around the world where "industrial" scale injection and storage of CO_2 is being undertaken at a level that is likely to match that required for commercial CCS operations (Table C). None of these existing operations are fully

[12] The potential for geological sequestration of CO_2 in Australia: preliminary findings and implications for new gas field development. Bradshaw, J, Bradshaw, B.E., Allinson, G., Rigg, A.J., Nguyen, V., and Spencer, A., 2002 - APPEA Journal, Vol 42 part 1 p. 25-46.

integrated CCS sites where capture of CO_2 from a coal fired power station is occurring. However many (perhaps a dozen) such operations are planned, especially in Europe, but they may be up to 10 years away before they are fully operational with power generation and capture, injection and storage. Sleipner (Table C) is the longest operating site (since 1996) and has the largest injection volume (1 Mt CO_2 / yr), but captures the CO_2 from a high CO_2 natural gas field. To make a significant difference to emission reduction, several thousand operations equivalent to Sleipner will be required.

Table C: Details of existing or planned "commercial" (industrial scale) CO_2 storage locations associated with high volumes of CO_2.

Location Name	Geological Storage location	Storage Location type	Source location	Source to storage site distance	Major SSM driver(s)
Sleipner (offshore Norway-North Sea - current operation)	Sleipner gas field (offshore platform)	saline clastic reservoir	Sleipner gas field offshore extraction platform	adjacent	Carbon tax, offshore extraction platform
Weyburn (onshore Saskatchewan, Canada - current operation)	Weyburn oil field (onshore)	enhanced oil production - carbonate reservoir	North Dakato coal gasification plant	300 km pipeline	Enhanced recovery economic benefit, Nearest reliable large CO_2 source
In Salah (onshore Algeria)	In Salah gas field (onshore)	saline clastic reservoir	Onshore gas extraction facility	adjacent	Internal company policy, viable local storage site
Snohvit (offshore/onshore Norway - Behrent Sea – under construction)	Snohvit gas / condensate field (offshore sub-sea)	saline clastic reservoir	Onshore gas extraction facility	2 x 150 km (offshore gas field to onshore extraction facility to offshore sub-sea completion at gas field)	Carbon tax, sub-sea completion, no injection sites local to onshore extraction facility
Gorgon (offshore/onshore Western Australia - planned)	Barrow Island (onshore)	saline clastic reservoir	Onshore (Island) gas extraction facility	adjacent (70 km pipeline from gas field to extraction facility)	Internal company policy, viable storage site local to proposed extraction facility

Sleipner

At the Sleipner gas field in the North Sea, Statoil has been injecting and storing 1 Mt CO_2 /year since 1996, through a single sub-vertical well. The CO_2 is co-produced with methane from a depth of 3000m from the high CO_2 gas field (10%), and separated on a separate offshore platform and injected into a shallow saline reservoir (Utsira Formation) at 1200m to 800 m. This is a "commercial" site, not a demonstration or pilot operation. From a financial viewpoint, the decision to proceed with the injection operation was due to a CO_2 emissions tax that the Norwegian government proposed to apply to this offshore site. The injection operation is planned to continue for the life of the gas production, which is 20 to 30 years. Many reports and published papers have been written on this operation, including risk assessments and a best practice guide. Considerable levels of monitoring have been undertaken with at least three 3D seismic surveys having been acquired since the CO_2 injection commenced. This seismic data and the subsequent analysis have proven that seismic monitoring will be a very effective monitoring tool in many, but not all, geological settings. Experiences learnt from the Sleipner operations has shown that assessment of the reservoir geology and engineering will not end at the commencement of injection, but will need to continue to be assessed as data comes in during the injection and storage process. Whilst Sleipner is an excellent example of the injection and storage process, it does not represent the main sources of CO_2 that need to be captured (i.e. coal fired power stations), and the Utsira Formation at the Sleipner site is in a unique geological setting that is unlikely to be duplicated often around the world. However, the Utsira Formation represents an extremely viable geological setting with a large storage potential for Europe.

In Salah

In Salah is a high CO_2 gas field in Algeria, which is operated by BP. Since 2004, BP has been separating and capturing 1 Mt CO_2 / year from the co-produced methane and injecting it into the formation from which the gas is being produced, but ~ 20km away from the field operations. This is a “commercial” site, not a demonstration or pilot operation. From a financial viewpoint, the decision to proceed with the injection operation was due to internal BP decision processes rather than any Algerian government incentives. The reservoir characteristics at In Salah are two to three orders of magnitude poorer than those at Sleipner, and so three horizontal wells with 1 km of horizontal section for injection have been drilled to ensure adequate injectivity. The reservoir is of a much more limited and discontinuous nature geologically than for the reservoir at Sleipner, and thus represents a much more realistic challenge as a storage site than some of the unique geological characteristics of Sleipner. The reservoir characteristics in Salah are more aligned with the geological characteristics that will be found in coal basins around the world, which is where most of the worlds coal fired power plants are located.

Weyburn

Weyburn is an enhanced oil recovery project, at an oil field that was discovered in the mid 1950’s in Saskatchewan Canada. It has been through several phases of secondary and tertiary recovery, the latest being flooding with CO_2. The CO_2 is being sourced from a coal mine where a coal gasification plant exists, and is piped 300km across the USA/Canadian border to Saskatchewan. The CO_2 will be injected for 4 years, after which CO_2 co-produced with the oil will be separated and re-injected. There are ~ 1800 wells at the oil field, ~ 600 of which are horizontal wells. This site is largely a commercial EOR operation, at which research into CO_2 storage is being undertaken. There has been extensive studies performed at this site, especially in terms of base line and ongoing monitoring, and it is an area where research activities will continue to further understand the fate of the injected CO_2. As the reservoir is a **carbonate rock** type (limestone and dolomite), and Australia has no commercial oil or gas fields in carbonates or viable carbonate saline reservoirs near major emissions sources, many of the aspects of this operation will have limited application to injection and storage sites in Australia, especially in terms of geochemical effects. Where thick and extensive carbonate reservoirs in Australia do occur, there are much better sandstone reservoir alternatives that would be considered in preference for storage.

Existing CCS Pilot or Demonstration Operations

There are currently no CCS pilot or demonstration projects in the world which integrate capture (from coal fired power station flue gas), injection and storage. There are numerous very small scale injection projects with a variety of technical outcomes that are being researched. Most are operating or have operated at very small injection volumes or have a limited technical focus of the vast array of CCS technologies that are being examined.

A pilot CO_2 injection project has been completed in the USA in Texas at the Frio project, and a second phase (Frio2) project is now planned. Numerous reports and publications have been generated from this study. Only a very limited CO_2 volume (1600 t) was injected at a site that would be highly unlikely to be used for any industrial scale CO_2 injection operation (http://www.beg.utexas.edu/). However from a monitoring, experimentation and equipment development viewpoint, the study was extremely valuable.

The first location to drill and inject CO_2 in Australia as part of a CCS pilot or demonstration project is being operated in southeast Queensland in the Bowen Basin by Stanwell, known as the ZeroGen project (www.zerogen.com.au). At this location, two wells have already been drilled and a third is planned, prior to a decision to expand the project to another more extensive phase. A variety of tests are being undertaken to assess the injectivity of the reservoirs in the deeper sections of the Bowen Basin. The reservoir quality in southeast Queensland and this ZeroGen site are much closer aligned to the conditions that are being experienced at In Salah in Algeria, and will resemble the reservoir quality and characteristics that will be commonly found in the coal basins and near most of the coal fired power plants of the world. The ZeroGen approach is an example of Australia putting itself into a position of being “storage ready”, with geological sites appropriately assessed adjacent to the locations where large scale injection is most likely to occur due to their proximity to large potential emission sources.