

NATIONAL CARBON MAPPING AND INFRASTRUCTURE PLAN – AUSTRALIA

FULL REPORT

**CARBON STORAGE TASKFORCE
SEPTEMBER 2009**

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REFERENCE

Carbon Storage Taskforce 2009, *National Carbon Mapping and Infrastructure Plan – Australia: Full Report*, Department of Resources, Energy and Tourism, Canberra

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The Hon Martin Ferguson AM MP
Minister for Resources and Energy
Parliament House
Canberra ACT 2600

Dear Minister,

The Carbon Storage Taskforce was established under the National Low Emissions Coal Initiative to develop a National Carbon Mapping and Infrastructure Plan. I have pleasure in submitting the Taskforce's report to you.

Carbon Dioxide Capture and Geological Storage (CCS) could play a key role in the portfolio of responses necessary to reduce greenhouse gas emissions in Australia at a substantial level. It is currently the only technology recognised as being capable of dealing with large quantities of emissions from stationary point sources. The availability of suitable geological storage sites underpins deployment of CCS. In the National Carbon Mapping and Infrastructure Plan, Australia now has a roadmap prioritising the development of suitable storage sites and the necessary pipeline infrastructure.

The Taskforce sought to take a measured and balanced approach in its investigation of the risks and opportunities presented by transport and storage of carbon dioxide. This included consideration of CCS on an integrated basis. Issues arising from carbon dioxide capture with energy generation and hydrocarbon extraction were considered to the extent they impacted on transport and storage issues.

The broad membership of the Taskforce provided a unique opportunity to consider the diverse, and sometimes conflicting, views of stakeholders regarding deployment of CCS in Australia. Stakeholders were drawn from all key industry sectors with an interest and expertise in carbon dioxide storage including coal, power generation, oil and gas, pipeline operators, geological survey agencies, unions and non-government organisations as well as representatives from the Commonwealth and state governments.

I would like to express my gratitude to my colleagues on the Taskforce who have worked with me to develop the National Carbon Mapping and Infrastructure Plan, as well as those who have provided support to us during this process. As noted in the report, the development of the Plan is just the first step. The challenge now is to maintain the momentum generated by stakeholders and implement the Taskforce's recommendations.

I commend this report to you.

Yours sincerely,

A handwritten signature in black ink, appearing to be 'Keith Spence', with a stylized, looped initial 'K' and a trailing flourish.

Keith Spence

7 September 2009

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KEY OUTCOMES

Mitigating greenhouse gas emissions requires the development and application of a portfolio of technologies. The technology identified as having the greatest potential to mitigate greenhouse gas emissions from large-scale fossil fuel usage is carbon dioxide capture and geological storage (CCS).

CCS combined with power generation and gas processing is expected to play a significant role in Australia. The first capture hub could be commercially viable as early as 2020–25.

Deployment of carbon dioxide (CO₂) transport and storage in Australia is technically viable and, under appropriate management regimes, safe.

Current geological and engineering activities must be accelerated and maintained over the next decade if the nation is to be in a position to capture the opportunity for commercial deployment beyond 2020.

Demonstration of the technology at significant scale is essential for investor confidence. Several demonstration storage sites could be ready by 2018. The Gorgon LNG project will be the world's largest CCS project (3.5 Mtpa) when sanctioned.

Apart from gas processing projects, commercial investment is highly unlikely until a carbon regime is introduced that is perceived to introduce costs, incentives or mandated outcomes that will persist in the medium to long term.

A significant proportion (more than 120 Mtpa) of Australia's future CO₂ emissions can be avoided by the capture of CO₂ from ten emissions hubs.

There is a high confidence that the east of Australia has aquifer storage capacity for between 70 and 450 years at an injection rate of 200 Mtpa, and that the west of Australia has capacity for between 260 and 1120 years at an injection rate of 100 Mtpa. These capacities have been estimated using a probabilistic analysis similar to that used for petroleum resource estimation. Assumptions on storage efficiency were highly conservative. It is possible that far greater capacity will be defined as basins and their CO₂ storage behaviour become better known.

The critical path for large scale deployment is now recognised to be the identification and development of suitable storage reservoirs. For aquifers, this is estimated to be between 11 and 13 years for a focussed program that is actively pursued and adequately funded. This time period assumes typical levels of investment, activity, and resource availability, and importantly, the activities are sequential (e.g. drilling takes place once seismic is acquired and interpreted). The time could be shortened by using multiple drilling rigs for example, or by overlapping activities (e.g. seismic and drilling). However, this incurs greater risk. The time would also be shortened if smaller scale injection was anticipated.

Carbon dioxide storage operations may be located in basins where other resources are, or will be, developed. The impact of the CCS activity on other resources and operations will need to be assessed for each case.

Transport and storage tariffs vary widely for hub/basin combinations. Preliminary cost indications for transport of large quantities of CO₂ from the Latrobe Valley to Gippsland Basin storage sites range around 10 \$/t CO₂ avoided, compared to around 30–60 \$/t CO₂ avoided for CO₂ transported from central east Queensland to the Eromanga Basin. For the power generation sector, this translates to an additional 1–10 \$/MWh for electricity generation costs, dependent on location. This does not include the costs for the new upstream generating and capture capacity.

It is essential that modelling of CCS as an element of energy futures in Australia should differentiate CCS costs by location.

The first capture hub is likely to be located in the Latrobe Valley in 2020–2025, due to its significant competitive advantage, arising from relatively low carbon transport and storage costs.

The different CO₂ transport and storage costs will become a factor in considering the optimal location of new plant, and new energy generation hubs may emerge. For example, locating new generating plant close to the Surat Basin storage areas would reduce the transport and storage tariff by more than 50%, to levels comparable with the Latrobe Valley to Gippsland costs.

The level of exploration, development and infrastructure activity needed to create Australia's transport and storage capacity appears manageable. The projected level of exploration and development activity benchmarks favourably with current levels of oil and gas activity. However, this petroleum activity is likely to continue or increase. Full scale deployment of CCS could at least duplicate the demand for similar resources. More than 5,000 km of large diameter pipeline infrastructure is needed to transport CO₂. This is a three-fold increase in Australia's current large diameter steel pipeline.

While CO₂ transport and storage has many parallels with oil and gas, it poses challenges that require a different approach and mix of skills and knowledge for industry and authorities.

There is a need for further research and development on CO₂ pipelines to develop assurance for the Australian community and its regulators that pipeline leaks can be avoided and that operational venting can be managed safely.

Public acceptance is essential for deployment, particularly onshore, and particularly for pipelines. The Taskforce has identified key concerns and suggests strategies to address them.

RECOMMENDATIONS

NATIONAL CARBON MAPPING AND INFRASTRUCTURE PLAN

The Taskforce recommends the following six element plan:

1. Implement a \$254m, strategically phased, pre-competitive exploration program.
2. Release exploration acreage in the onshore Surat and Perth basins as soon as possible in addition to those offshore areas released in March 2009.
3. Develop several transport and storage demonstration projects at a significant scale of 1 Mtpa CO₂ or more, which are integrated with CO₂ capture demonstration projects.
4. Support pipeline infrastructure development that is designed to incorporate economies of scale, competitive long term costs and uncompromising safety standards.
5. Identify and recommend incentives to drive competitive CO₂ storage exploration over the period 2010–2017, in concert with other policy and fiscal settings established to support deployment of low emissions technologies, including CCS.
6. Develop and implement a Communication Strategy.

These plan elements incorporate the following recommendations:

PLAN ELEMENT 1: PRE-EXPLORATION

- 1a) Conduct the phased, gated, pre-competitive exploration program totalling \$254 million developed by the state government geological surveys and Geoscience Australia to assess basins of strategic importance. Programs specific to each basin need to be conducted concurrently, and commence now. The estimated cost is significantly in excess of the \$50 million provided by the Commonwealth. As pre-exploration proceeds, there may be a need for further pre-competitive exploration investment.
- 1b) Establish a Review Committee to consider the pre-competitive exploration programs across the jurisdictions, charged with:
 - optimising the expenditure on the programs by aligning them in timing and location.
 - updating the priorities of the program in light of near term results from exploration programs and tendering of areas.
 - reporting back to Government through the Ministerial Council on Mineral and Petroleum Resources (MCMPR) on the results, their implications and expenditure.
- 1c) Form a clear understanding of the data types and sources relevant to basin management for CO₂ storage, and government policy and requirements in relation to provision of this data by industry operators.

The Taskforce recommends that this process is managed by the Upstream Petroleum and Geothermal Subcommittee (UPGS), reporting to the MCMPR in the first half of 2010.

PLAN ELEMENT 2: EXPLORATION

- 2a) Place a high priority on acreage release over the onshore Surat and Perth basins (in addition to the offshore areas already released). Acreage release in these basins in the near term is essential if timeline targets for significant CCS deployment are to be met.
- 2b) Enact legislation enabling CO₂ storage in onshore Western Australia and New South Wales at the earliest opportunity.
- 2c) Encourage consistency of exploration and storage legislation in different jurisdictions to facilitate investment.

PLAN ELEMENT 3: DEMONSTRATION PROJECTS

- 3a) Build demonstration projects at significant scale (greater than 1 Mtpa CO₂) linking capture, transport and storage elements so that the risks associated with the operability of the overall integrated system can be understood and addressed. This is crucial for investor confidence.
- 3b) Support development of demonstration capture plants and storage reservoirs that are able to evolve into demonstration hubs, to show viability of systems at the scale necessary for wide spread deployment, and to capture economies of scale. This recommendation does not preclude development of 'stand alone' CCS systems, if a particular system can demonstrate competitive benefits.
- 3c) Place priority on proposals for significant-scale, linked demonstration projects in the Gippsland, Surat and Perth basins as these are the most likely to develop as the first capture and storage hubs.
- 3d) Design demonstration projects to develop a better understanding of storage, including storage efficiency, migration behaviour and monitoring techniques.

PLAN ELEMENT 4: INFRASTRUCTURE

- 4a) Develop a nationally consistent approach to CO₂ pipeline regulation.
- 4b) Undertake activities designed to build capacity for regulators, industry operators and the public, and that develop awareness that CO₂ transport and injection infrastructure can be developed and operated safely in Australia. The program should primarily draw on existing international experience in CO₂ pipeline construction and operations, supplemented by a targeted R&D program designed to complement international programs.
- 4c) Prioritise investment in emissions hub-storage basin combinations that are lowest cost, and optimise initial infrastructure design for anticipated future loads.
- 4d) Co-ordinate national and local planning to ensure options for strategic pipeline corridors for potential future use are retained.
- 4e) Prioritise deployment of lowest cost options that are more likely to remain economically competitive against other energy generation options in the longer term (30–40 years). Use early learning to demonstrate proof of concept and identify opportunities for cost reduction, before committing to longer distance pipelines.

PLAN ELEMENT 5: POLICY AND FISCAL SETTINGS

- 5) Identify and evaluate CO₂ storage exploration incentives that could be applied over the period from 2010 to 2017. The Taskforce should provide a recommendation on appropriate incentives policy to the Minister for Resources and Energy in the first quarter of 2010.

PLAN ELEMENT 6: COMMUNICATION

- 6) The Taskforce should consult with its members and other CCS stakeholders with a view to the development of a CCS communicators' forum, or similar structure, which will provide a coordination node for CCS in Australia to:
 - develop credible, verified and consistent messages in the context of the whole portfolio of responses to climate change, and liaise with relevant groups developing other responses
 - create a reference source to avoid duplication; and
 - on occasions, and if agreed, coordinate a response to a specific event.

1 INTRODUCTION

Governments in Australia, Europe and the United States are taking action to mitigate the impact of greenhouse gas emissions on climate change. Australia is one of the nations likely to be affected by climate change earliest and hardest. Postponing action to mitigate greenhouse gas emissions is considered likely to result in substantially greater costs, and impacts.¹ There is an urgent need to mitigate greenhouse gas emissions globally and Australia has an opportunity to contribute to this action at many levels.

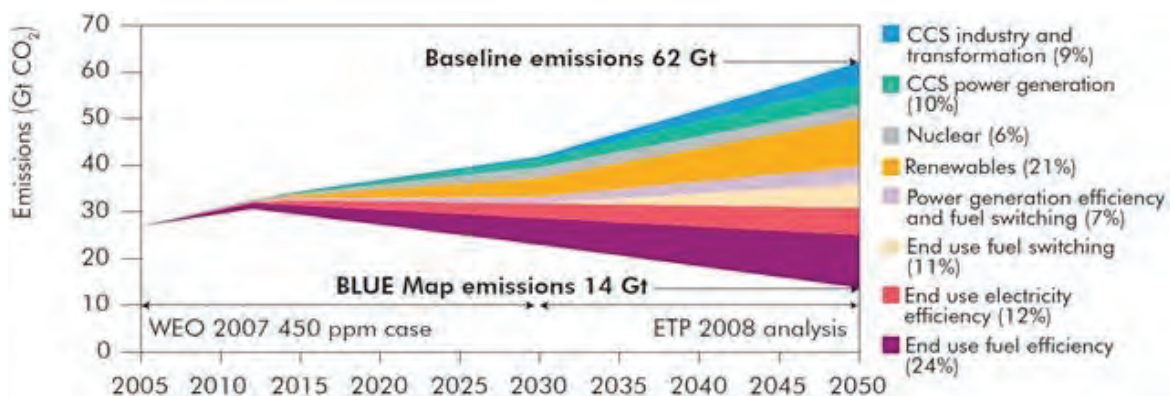
Currently, about 69% of all carbon dioxide (CO₂) emissions and 60% of all greenhouse gas emissions are 'stationary energy'-related. The International Energy Agency² (IEA) projects that without policy change, world energy demand will grow by 45% between 2006 and 2030. Even with the growth in renewable energy sources, fossil fuels are expected to remain major sources of the world's energy in the coming decades.

The IEA³ projects that CO₂ emissions from energy use will increase by 130% by 2050, largely due to increased fossil fuel usage, in the absence of new policies or supply constraints. The Intergovernmental Panel on Climate Change (IPCC) 4th Assessment Report⁴ found that such a rise could lead to a temperature increase in the range of 4 °C to 7 °C, with major impacts on the environment and human activity. The IPCC concluded that Australia's water resources, coastal communities, natural ecosystems, energy security, health, agriculture and tourism would all be vulnerable to climate change impacts if global temperatures rise by 3 °C or more.

It is widely agreed that a halving of 'stationary energy'-related CO₂ emissions is needed by 2050 to limit the expected temperature increase to less than 3 °C.

To achieve this will require an energy sector transformation on a massive scale. The IEA projections of global responses include increased energy efficiency, increased renewable energies and nuclear power, and the decarbonisation of power generation from fossil fuels (Figure 1). At present, the technology identified as having the greatest potential to mitigate greenhouse gas emissions from large-scale fossil fuel usage is CO₂ capture and geological storage (CCS).

Figure 1: Technologies for reducing global 'stationary energy'-related CO₂ emissions by 2050



Source: IEA (2008), *Energy Technology Perspectives 2008*.

1 Garnaut, R 2008, *The Garnaut Climate Change Review: Final Report* / Ross Garnaut, Cambridge University Press, Port Melbourne, Victoria

2 International Energy Agency 2008, *Energy Outlook 2008*

3 International Energy Agency 2008, *Energy Technology Perspectives 2008*

4 Intergovernmental Panel on Climate Change (IPCC) 2007, *IPCC 4th Assessment Report*

CCS will need to contribute nearly 20% of the necessary emissions reductions to reduce global greenhouse gas emissions by 50% by 2050 at a reasonable cost⁵, and so CCS is essential to the achievement of deep emission cuts.

The IEA also found that deployment of CCS would significantly reduce the cost of reducing global emissions. It estimated that without CCS, the annual cost for emissions halving in 2050 is USD1.28 trillion per year higher, an increase of 71%.⁶ In July 2008, the G8 countries acknowledged the important role of CCS by setting a target of 20 large-scale CCS demonstration projects to be committed by 2010, with a view to beginning broad deployment by 2020.

1.1 AUSTRALIAN CONTEXT

The Australian Greenhouse Gas Inventory reports that Australia's net total greenhouse gas emissions in 2006 were 576.0 million tonnes (Mt) CO₂-equivalent (CO₂e).⁷

Figure 2: Greenhouse gas emissions by sector in Australia in 2006⁷

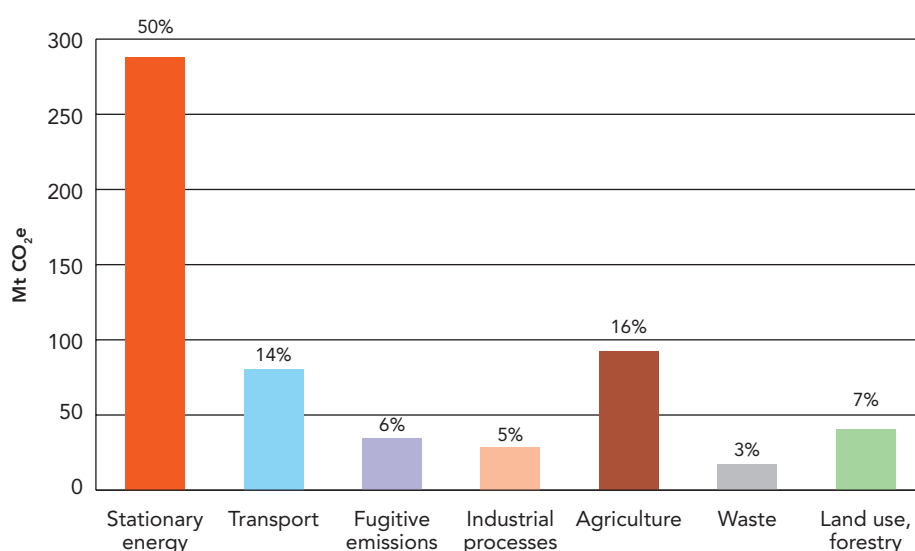


Figure 2 shows the greenhouse gas emissions by sector in 2006. The energy sector was the largest source of greenhouse gas emissions at 69.6% of the total (400.9 Mt CO₂e).

Carbon dioxide is the most significant of the greenhouse gases in Australia's inventory, making up 74.3% (427.8 Mt) of total CO₂e emissions, followed by methane, which comprises 20.5% (118.3 Mt CO₂e). The energy sector is the major contributor to CO₂ emissions at 86% (367.8 Mt).

The energy sector component includes emissions from:

- *stationary energy* – emissions from fuel combustion to provide energy in energy industries, especially electricity generation; manufacturing industries and construction; and other sectors;
- *transport* – emissions from road, rail and domestic air and water transport; and
- *fugitive emissions* – emissions, other than those attributable to energy use, from coal mining and handling (solid fuels), and oil and natural gas production, processing and transport.

The largest emission contributor to the energy sector is stationary energy, which made up 50% or 287.4 Mt CO₂e of Australia's emissions in 2006. The vast majority of stationary energy emissions are CO₂, with methane and N₂O contributing just 1.1 and 1 Mt respectively.

⁵ International Energy Agency 2008, *CO₂ Capture and Storage – A key carbon abatement option*

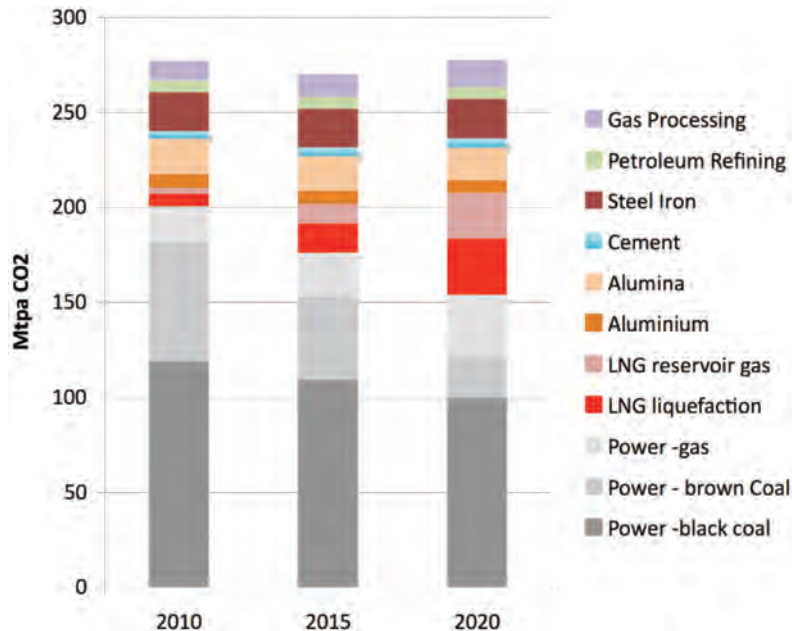
⁶ International Energy Agency 2008, *Energy Technology Perspectives 2008 – Scenarios and Strategies to 2050*, July 2008.

⁷ Department of Climate Change 2006, *National Greenhouse Gas Inventory 2006*, Department of Climate Change, Canberra. Note: emissions data for 2007–8 are not yet published.

1.1.1 Stationary Emission Sources

Stationary CO₂ emitters are the target for CCS. However, to benefit from economies of scale, there is a need to aggregate emissions from clusters or 'hubs' of emitters to provide efficient transport and storage of CO₂.

Figure 3: Projected stationary emissions by industry⁸



A baseline of likely annual stationary energy CO₂ emissions has been developed by ACIL Tasman for the Taskforce.⁸ The baseline gives an estimate, by location, of the annual CO₂ emissions for the years 2010, 2015 and 2020 for emitters or geographically co-located groups of emitters within the stationary energy sector.

Figure 3 shows stationary emissions in 2010 are projected to be around 277 Mt of CO₂. Electricity generation from black coal, brown coal, and gas represents around 70% of this sector's 2010 projected emissions at 200 Mt CO₂ with the remainder coming from direct combustion.⁹

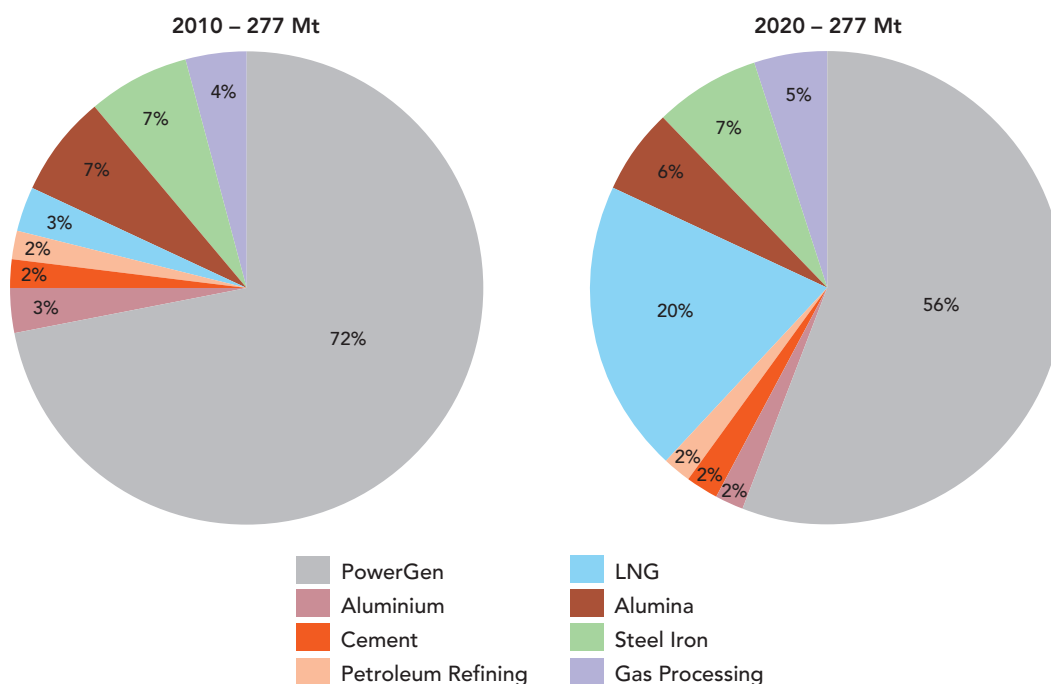
Although total stationary emissions are projected to fall by 2015, they are expected to return to 277 Mt in 2020. This is due to increasing emissions related to Liquefied Natural Gas (LNG – due to new developments), which offset an expected reduction in power generation emissions due to fuel switching (coal to gas) and more use of renewable energy under the Mandatory Renewable Energy Target (MRET) scheme.

Projected stationary emissions in 2010 are compared with projections for 2020 in Figure 4. The most significant changes evident are the reduction of emissions from electricity generation from 72% to 56%, and the increase of LNG-related emissions from 3% in 2010 to 20% in 2020, owing to new developments coming on stream. The other sources of concentrated emissions from the stationary energy sector remain relatively constant during the period. These emissions could be considered for CCS if economic.

⁸ ACIL Tasman 2009, *Australian stationary energy emissions – an assessment of stationary energy emissions by location suitable for capture and storage*, report prepared for the Carbon Storage Taskforce, Department of Resources, Energy and Tourism, Canberra

⁹ These include cement, metals; processing, pulp, paper and print; non-metallic minerals; and food and beverages; small combustion such as home heating, on-site diesel generation, and on-farm machinery.

Figure 4: Projected stationary CO₂ emissions in 2010 and 2020 by sector



1.1.1.1 Electricity Sector Emissions

Electricity sector emissions result from combustion of black coal, brown coal, gas and some other fuels in the generation of power. Figure 5 below shows that coal-fired power generation accounts for 90% of projected power generation CO₂ emissions in 2010. To put coal-fired power generation in context, it represents 65% of projected total stationary emissions in 2010 and the majority of emissions are concentrated in just a few emitters. Some 146 power generators were included in the modelling, but just 15 generators (all brown or black coal plants) account for 73% of projected emissions from power generation in 2010. Emissions from brown coal firing are projected to decline significantly by 2020 (emissions down by 40.8 Mt) as generators switch to gas under the influence of a Carbon Pollution Reduction Scheme (CPRS).

Figure 5: Projected power generation emissions in 2010 and 2020

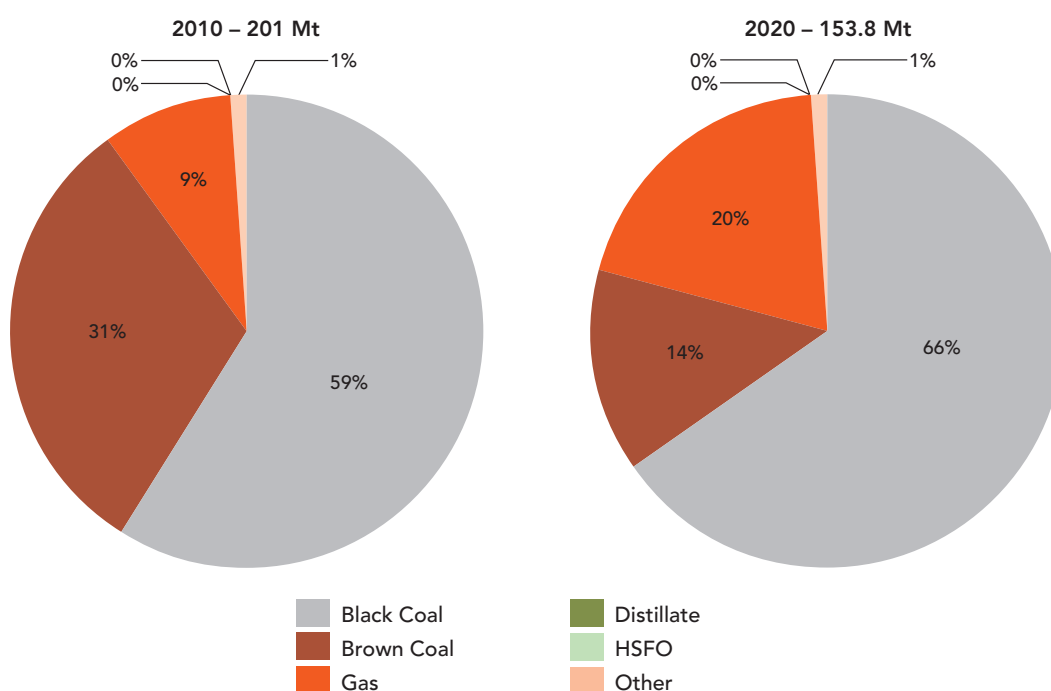
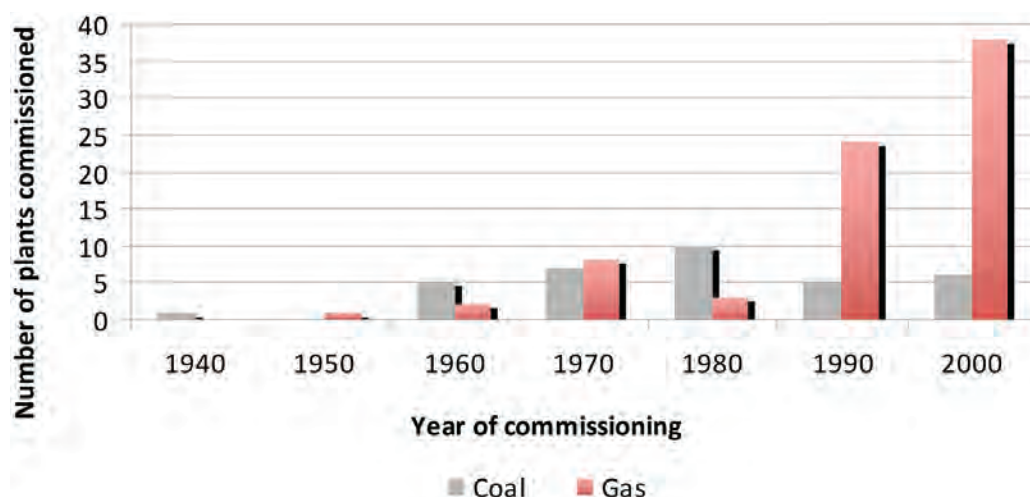


Figure 6 shows that Australia's coal-fired plants were mainly commissioned during the 1970s and 1980s, whereas in recent years the trend has been to more gas-fired power generation. While the greenhouse gas efficiency of gas-fired power generation (e.g. combined cycle gas turbines) is much lower at 0.4 to 0.5 tonnes per MWh compared with coal at 1 to 1.2 tonnes per MWh, the exhaust from gas-fired power generation contains much lower concentrations of CO₂ and is generally more difficult to capture than that from coal-fired facilities.

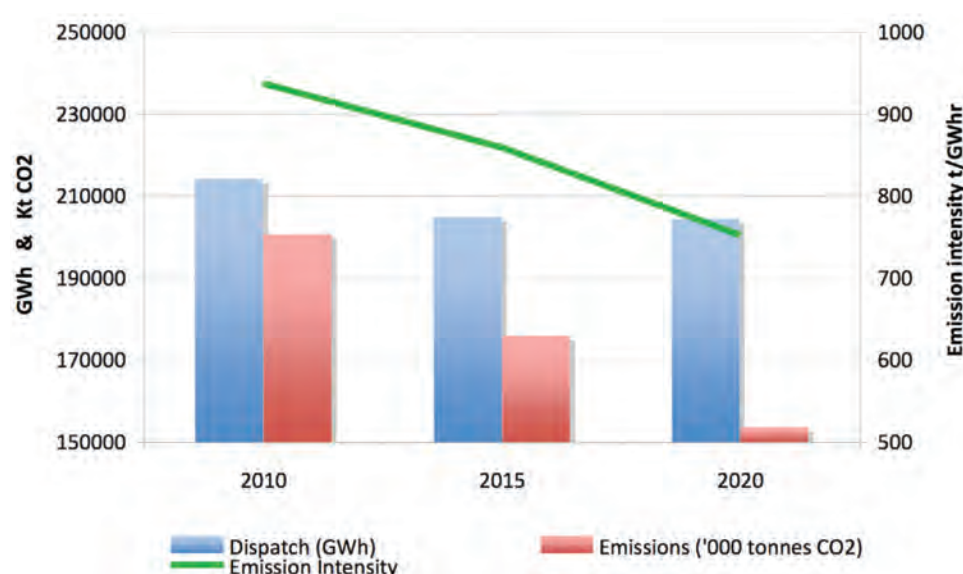
Figure 6: Age of power generation fleet



As shown in Figure 7 below, the total electricity sector projections show emissions declining from 72% of total stationary emissions in 2010 to 56% in 2020. The change in emissions over time for the electricity sector is important – particularly within the competitive wholesale electricity markets of the National Electricity Market (NEM) on Australia's east coast and the South West Interconnected System (SWIS) on the west coast. While electricity demand is expected to continue to grow, the effect of explicit carbon pricing through the CPRS is projected to result in a decrease in emission intensity over the period to 2020.

Indeed, with carbon prices above \$35/tonne CO₂, the modelling suggests that a number of large coal-fired power stations will no longer be commercially viable and will be forced into early retirement. These are forecast by ACIL Tasman to be replaced by gas-fired combined cycle gas turbine units and other technologies (see Section 7 later in the report).

Figure 7: Projected emission intensity – power generation sector



This trend highlights an interesting paradox for CCS efforts: the longer the lead-time for commercial deployment of CCS technology, the smaller the electricity sector emissions that can potentially be captured.

However, once CCS technology is proven and is commercially competitive with alternative generation technologies (on a carbon inclusive basis), there is potentially a growing demand for CCS applications from the sector.

1.1.1.2 Gas Production Based Emissions

Emissions associated with the production and processing of natural gas come from two main sources:

1. Reservoir CO₂ that naturally occurs associated with hydrocarbon gases in the geological reservoir and normally removed as a routine part of natural gas processing. Concentrations of CO₂ in Australia's natural gas fields vary greatly from less than 1 to as high as 20% of total reservoir gas.
2. CO₂ generated by combustion of fuel in the production and processing of natural gas. Where LNG is produced, these combustion sources can be significant.

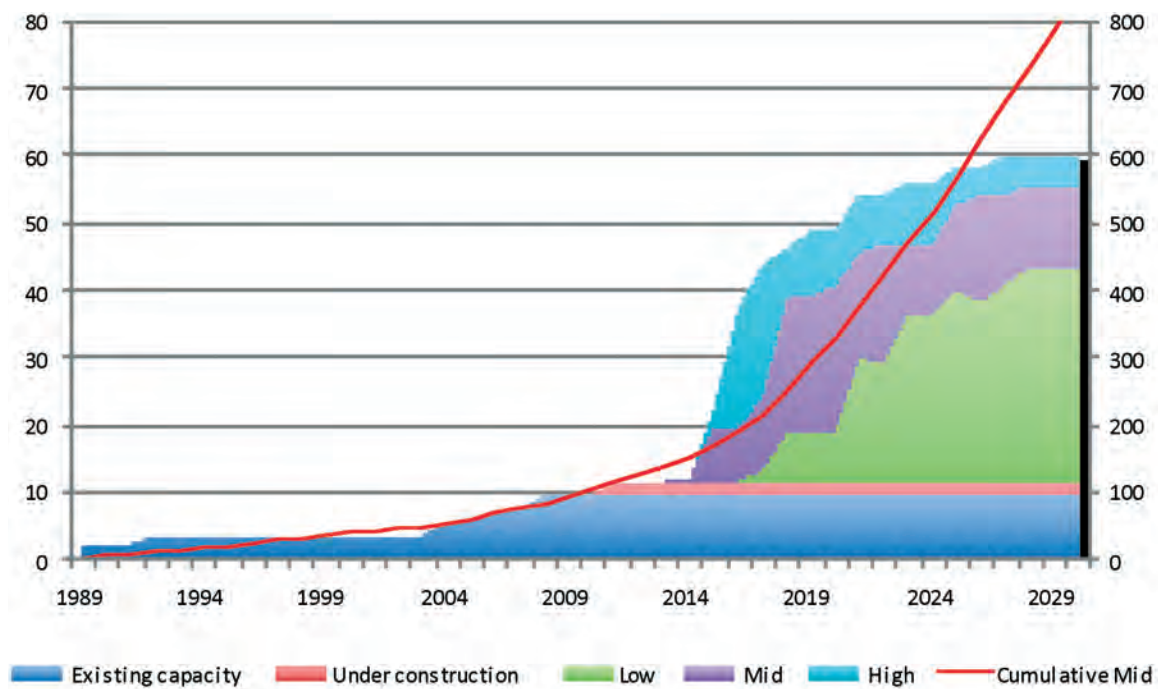
The following section discusses the opportunities to capture emissions from the LNG facilities planned as part of the industry's growth in Australia. Although there is potential for capturing emissions from plants that process gas for domestic consumption, they have been excluded from the modelling. Despite the potential growth in demand for natural gas, there is some uncertainty around these developments.

ACIL Tasman has estimated emissions from LNG facilities using representative liquefaction and upstream emission factors, and specific reservoir compositions. Fugitive emissions (e.g. methane) have not been modelled as they represent less than 1% of total emissions. Emissions generated by LNG shipping have also been excluded, as the focus of this work is on stationary emissions that occur primarily within Australia.

Two major LNG plants operate in Australia: the North West Shelf Project in Western Australia; and the Darwin LNG project in the Joint Authority Area/Northern Territory. The combined output of these is ~20 Mtpa of LNG and 9.5 Mtpa CO₂ (1.4 Mtpa of reservoir CO₂ and 8.1 Mtpa of CO₂ from production and liquefaction processes). This represents 3% of total national stationary emissions. The Pluto Project on the North West Shelf, currently under construction, is expected to begin production in 2011. Pluto's reservoir CO₂ emissions, which will be relatively small, will be offset.

Figure 4 earlier in this section, shows that LNG-related emissions are projected to grow significantly, representing 19% of Australia's stationary CO₂ emissions by 2020 as a number of new LNG projects commence production. Given the uncertainty about the timing of these projects and the magnitude of their subsequent contribution to Australia's stationary CO₂ emissions, low, mid and high development scenarios have been defined based on pessimistic, likely and optimistic timing of project start-ups.

Figure 8: Mid-case LNG scenario for CO₂ emissions



These scenarios indicate that by 2020, LNG production could be between 37 and 90 Mtpa (low and high cases respectively). The corresponding emission levels (assuming no storage of reservoir CO₂) are projected to be between 19 and 49 (low and high cases respectively). The mid-case scenario (Figure 8) sees emissions at 39 Mtpa, which would represent 15% of Australia's stationary emissions in 2020. Cumulative Australian CO₂ emissions associated with LNG are projected to reach 325Mt CO₂ by 2020, and 809 Mt by 2030 in the mid-case scenario.

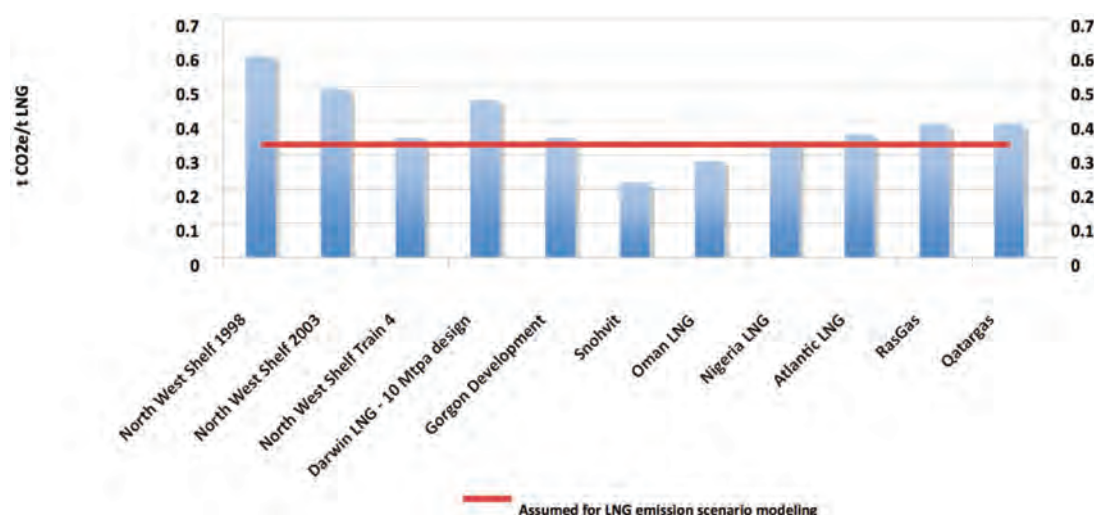
The Gorgon Project plans to capture and re-inject reservoir CO₂ into underground storage.¹⁰ At around 3.5 Mtpa of CO₂, this would be the largest example of underground storage of CO₂ in the world. Successful storage at the scale proposed by the Gorgon Project will play an important role in demonstrating the feasibility of, and building community confidence in, the commercial scale application of this technology.

The ability to capture reservoir CO₂ emissions from LNG (and domestic gas) processing plants may represent a low cost emissions abatement opportunity, as the technologies mature. Some future LNG projects may be located close to suitable storage sites so that capture and storage of reservoir CO₂ from these projects may be taken up relatively early.

However, capturing CO₂ resulting from fuel use in upstream processing and liquefaction is more problematic. LNG liquefaction plants have typically many sources of emissions that are distributed throughout the plant, making their capture into a single stream difficult. Additionally, power generation is usually from open cycle gas turbines (OCGT). The exhaust stream from OCGTs has low CO₂ concentrations, and contains oxygen levels that adversely affect the amine chemical used for CO₂ separation and capture.

¹⁰ Gorgon Gas Development Revised and Expanded Proposal – Public Environmental Review, published in September 2008

Figure 9: Greenhouse Gas Efficiency: Australian and international LNG facilities



(Source: Environmental Impact Statement/Environmental Review and Management Program for the Gorgon Development, 2005)

In order to illustrate the potential for improved emission efficiency of LNG trains, Figure 9 compares the various technologies deployed and proposed for some Australian and international LNG projects. The LNG scenario modelling done by ACIL Tasman for the Taskforce assumes a greenhouse gas efficiency of 0.33t CO₂e per t LNG. A variety of factors including plant size, air cooled versus water cooled, climatic conditions and gas composition (rich/lean, inert content) all influence the emissions-efficiency of LNG facilities. Although the Snohvit project and Oman LNG project have achieved efficiencies of 0.22 and 0.28 respectively, their geographic characteristics make comparison with Australian projects difficult from an emissions perspective. For example, Snohvit is water cooled (seawater temp 4 °C) and in a very cold climate. Oman LNG is also water-cooled and a smaller train size to the North West Shelf Project.

Emissions from liquefaction of LNG can be reduced by improving the energy efficiency of the process. However, the energy efficiency of the process needs to be addressed before the new LNG process trains are constructed because retrofitting is costly and difficult to justify commercially.

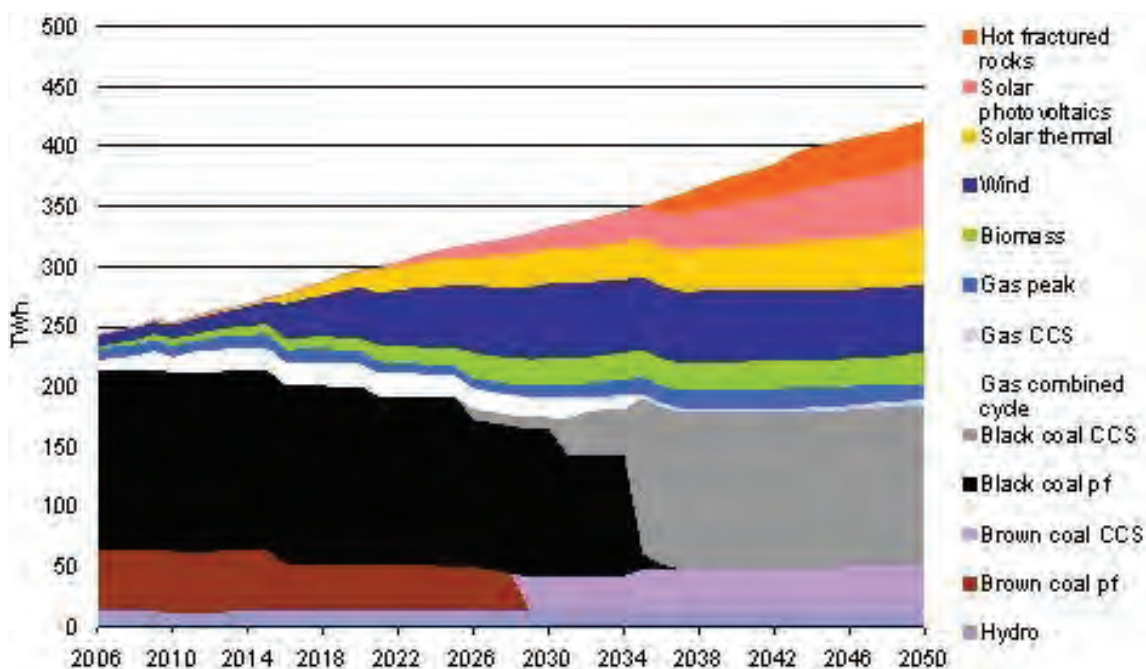
1.1.2 Future Role of CCS and Other Technologies

At the time of writing, the Australian Government's CPRS is planned to come into effect in July 2011. The CPRS will be the primary mechanism through which Australia will seek to meet its emissions reduction objectives. Under this scheme, a carbon permit price increases the costs of emissions from coal and gas-fired power over time, thereby increasing the competitiveness of the higher cost, lower emission alternatives such as renewables and CCS. The other major elements of the Government's mitigation strategy are: the expanded Renewable Energy Target; investment in renewables and carbon capture and storage; and action on energy efficiency.

The electricity sector is expected to make a substantial contribution to abatement and is very important for achieving national emission reduction. Figure 10 shows CSIRO's national projection for the power generation sector under the CPRS. In CSIRO's projection, wind and natural gas electricity generation are projected to be the main new power plant investment in the first decade after the CPRS is introduced, as these are the two lowest cost abatement opportunities in the electricity generation sector initially and other technologies are in the demonstration stages.

Solar thermal and solar photovoltaics are expected by CSIRO to be the next technologies to emerge as economically viable emission abatement technologies. Solar thermal power is expected to be in the form of high temperature concentrating towers. Hot fractured rocks and fossil fuel power generation with CCS are projected to be economically viable in the period from 2025.

Figure 10: Projected Australian electricity generation portfolio under CPRS-5¹¹



Source: CSIRO.

Coal-fired power generation with CCS is projected to play a significant future role, being more than 40% of projected power generation capacity in 2050.¹¹

There is a wide range of possible future energy-mix scenarios, and the timing and level of contribution of different technologies could vary significantly. It is important, therefore, that a wide range of scenarios is considered when developing policy responses.

The Australian Academy of Technological Sciences and Engineering (ATSE) recently reported¹² that for a typical energy demand growth scenario of 1.4% per annum (similar to ABARE projections) and a portfolio of new technologies installed, around \$250 billion in new technology investment will be required by 2050. The investment cost is dependent on the portfolio of technologies adopted, especially the higher cost and lower capacity-factor technologies such as wind and solar. ATSE's results for projected investment costs are consistent with recent studies, including the IEA study and the recent Australian Government Treasury report.¹³

ATSE concludes that it is unlikely that any single technology will achieve the CO₂ reduction outcome targets now being proposed. Rather, the response will require the development and application of a portfolio of technologies.

1.2 CARBON DIOXIDE CAPTURE AND GEOLOGICAL STORAGE IN AUSTRALIA

Australia has an active research effort underway. The Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC) and CSIRO are leading research into CCS. A number of small-scale CCS demonstration projects have commenced at Australian power stations. A pilot carbon storage project is currently underway in southwestern Victoria, with 65,000 tonnes of CO₂ injected and stored to date. Carbon capture technologies to entrap CO₂ emitted as flue gas have also progressed.

¹¹ CSIRO 2009, *Dealing with carbon – what is Australia's carbon balance & footprint and how do we deal with the cost of adaption?*, presented at the AICC June 22 2009

¹² Australian Academy of Technological Sciences and Engineering (ATSE) 2008, *Energy Technology for Climate Change, Accelerating the Technology Response*, ATSE, Melbourne

¹³ Department of the Treasury 2008, *Australia's Low Pollution Future – The Economics of Climate Change Mitigation*, Department of the Treasury, Canberra

The Australian Government has established the National Low Emissions Coal Initiative (NLECI), a \$400 million program to accelerate the development and deployment of technologies that will reduce emissions from coal use. It includes funding for research and to support the trial of different technologies. An allocation of \$50 million has been provided to progress CO₂ storage initiatives.

In September 2008, the Australian Government announced the establishment of the Global Carbon Capture and Storage Institute (GCCSI) to help coordinate and drive the concerted global effort called for by global leaders. The Government is also supporting a range of CCS-related projects with key international partners, including China, through the Asia-Pacific Partnership on Clean Development and Climate and through its membership of the Carbon Sequestration Leadership Forum (CSLF).

The Federal Government amended the *Offshore Petroleum Act 2006* in November 2008 to introduce a regulatory regime for CCS activities in Commonwealth offshore waters. In March 2009, ten offshore areas were released for the exploration of greenhouse gas storage. Victoria, Queensland and South Australia have also passed legislation for the conduct of CCS activities onshore.

The 2009 Commonwealth Budget included \$4.5 billion for the Clean Energy Initiative, of which \$2 billion will go to building two to four industrial-scale CCS projects in Australia, in pursuit of the G8 goal to develop at least 20 large scale integrated CCS projects globally by 2020. The remainder will support the construction and demonstration of large-scale solar power stations in Australia through the Solar Flagships Program, and establish a new body, the Australian Centre for Renewable Energy (ACRE), to promote the development, commercialisation and deployment of renewable technologies, through a commercial investment approach.

In August 2009, the Australian Government announced an additional five years of funding for the CO₂CRC to take forward its CCS research and development, including further work on pilot scale capture and storage. A five year funding package was also provided for the newly created Energy Pipelines CRC, which has a work program which includes pipelines carrying CO₂ emissions.

Through a voluntary industry levy, the Australian coal industry has committed over \$1 billion to accelerate the deployment of low emission coal technologies, at commercial scale, in Australia, in order to reduce CO₂ emissions from coal-fuelled power generation and manufacturing through the development of low-emissions demonstration projects including CCS.

1.3 CARBON STORAGE TASKFORCE

The Australian Government established the Carbon Storage Taskforce (the Taskforce) in October 2008 to bring together key industry sectors with an interest and expertise in carbon storage including coal, power generation, oil and gas, pipeline operators, geological survey agencies, unions and non-government organisations as well as representatives from the Australian and state governments, to develop a National Carbon Mapping and Infrastructure Plan (the Plan).

The primary aim of the Plan is to develop a road map to drive prioritisation of, and access to, a national geological storage capacity to accelerate the deployment of CCS technologies in Australia. The full Terms of Reference for the Taskforce are included at Appendix A.

1.4 AUSTRALIAN LEGISLATION RELEVANT TO CO₂ STORAGE

Legislation is in place covering the injection and geological storage of CO₂ in Commonwealth waters and for onshore Victoria, Queensland and South Australia. Legislation is being developed by New South Wales and West Australia for those states' onshore areas.

However, this legislation is not consistent, with the primary difference being the treatment of pre-existing rights and long-term liability.

1.4.1 Pre-existing Rights

Under the Commonwealth legislation the responsible Commonwealth Minister has to be satisfied that a greenhouse gas storage activity does not pose a significant risk of a significant adverse impact on pre-existing petroleum rights. Victorian legislation, however, provides that if two activities cannot coexist then the decision will be made on the basis of the public interest. In South Australia, the rights of petroleum operators to store greenhouse gas are grandfathered because these formed part of their rights before the detailed storage amendments were made to the South Australian legislation. Queensland legislation provides for a detailed dispute resolution mechanism with the Minister being the final arbiter. It is not clear what the requirements will be under NSW and Western Australian legislation at this stage.

These differences between jurisdictions reflect different resource bases and the rights that were in existence before greenhouse gas storage legislation was introduced.

1.4.2 Long Term Liability

The Commonwealth's legislation takes a staged approach to liability.

- Once injection ceases, the title holder applies for a closing certificate. The Minister must make a decision within five years on whether to grant this certificate, and will only grant it if post-injection monitoring shows that the stored substance does not pose a significant risk to human health or the environment.
- Once the closing certificate is issued the title holder's statutory obligations cease but common law liabilities will continue.
- At least 15 years after the closing certificate is issued, and subject to the behaviour of the stored substance being as predicted, the Commonwealth will take over common law liabilities.

Queensland and Victorian legislation, however, leave common law liability with the titleholder in perpetuity and do not establish set periods for decision-making. In South Australia, the titleholder can apply to the Minister for the Government to take over long-term liability. While this inconsistency could make storage in areas under Commonwealth jurisdiction more attractive than onshore storage, other cost factors will almost certainly be much more important.

1.4.3 Other Relevant Developments

- The Ministerial Council on Mineral and Petroleum Resources (MCMPR) released the Regulatory Guiding Principles¹⁴ in order to achieve a nationally consistent approach to the implementation of the CCS scheme, which takes into account Ecologically Sustainable Development, the Intergovernmental Agreement on the Environment, Principles of Good Regulation and relevant Council of Australian Governments (COAG) Occupational Health and Safety Principles.
- The Australian Government Department of Environment, Water, Heritage and the Arts released a draft of the Environmental Guidelines for Carbon Dioxide Capture and Geological Storage 2008 to build on the Regulatory Guiding Principles endorsed by the MCMPR.
- There are numerous existing regulations that are likely to impact on CCS projects in Australia, which arise both under domestic law (under legislation and at common law), as well as at international law, and are driven by the key risks associated with each stage of a CCS project. The existing petroleum regime in Australia provides an adequate starting point for developing a legislative framework for Australian CCS projects.

¹⁴ MCMPR 2005, *Carbon Dioxide Capture and Storage Australian Regulatory Guiding Principles*, Ministerial Council on Mineral and Petroleum Resources, Canberra, Australia

2 AUSTRALIAN CO₂ EMISSION HUB CONCENTRATIONS

2.1 TASKFORCE ACTIVITIES AND TECHNICAL FEASIBILITY

The Taskforce identified ten hubs or concentrations of Australia's stationary emissions that are expected to account for 211 Mt or 76% of stationary emissions in 2020.¹⁵

The Taskforce identified a priority list of potential storage basins and determined indicative estimates of their storage capacities and injection characteristics.¹⁶ These sites were matched with emissions hubs, to generate estimates of transport and storage tariffs.¹⁷

The study identified that transport and storage costs vary significantly for different hub/basin combinations. This cost range was included in a model examining energy futures for the NEM under different scenarios.

A range of technical matters relating to pipeline transport and storage were investigated in detail. The Taskforce also investigated the opportunity for commercial deployment of CCS in Australia, and community opinions relating to CCS.

It is the view of the Taskforce that a significant proportion (more than 20%) of Australia's future CO₂ emissions can be avoided by the capture, transport and geological storage of CO₂ from Australia's stationary emission sources.

2.2 EMISSIONS AND HUBS

Ten concentrations of stationary emitters have been identified across Australia, where emitters are (or in the case of the Kimberley hub, are likely to be) located sufficiently close together to allow the gathering of captured CO₂ through a hub. The ten key areas of emission concentration (moving clockwise from the northeast) are:

- Gladstone, Rockhampton and Biloela – Queensland;
- The South East Surat Basin – Queensland;
- The Hunter Valley and Newcastle – New South Wales;
- South NSW West/Lithgow – New South Wales;
- The Latrobe Valley – Victoria;
- Port Augusta – South Australia;
- Perth and Kwinana – Western Australia;
- Pilbara – Western Australia;
- Kimberley – Western Australia; and
- Darwin – Northern Territory.

Figure 11 (below) shows the geographical distribution of these stationary emission sources, while Figure 12 shows the projected CO₂ emissions by hub and industry in 2020.¹⁸

¹⁵ The modelling included stationary emissions only, not total emissions forecast to 2020 in Australia.

¹⁶ A montage of geological information and characteristics was developed for each basin. The montage of the Gippsland basin is shown as an example in Appendix E.

¹⁷ Tariff: the cost per tonne of CO₂ avoided, calculated using the net present value of cash flows and avoided CO₂ over a 25 year asset life.

¹⁸ ACIL Tasman 2009, *Australian stationary energy emissions: an assessment of stationary energy emissions by location suitable for capture and storage*, report prepared for the Carbon Storage Taskforce, Department of Resources, Energy and Tourism, Canberra

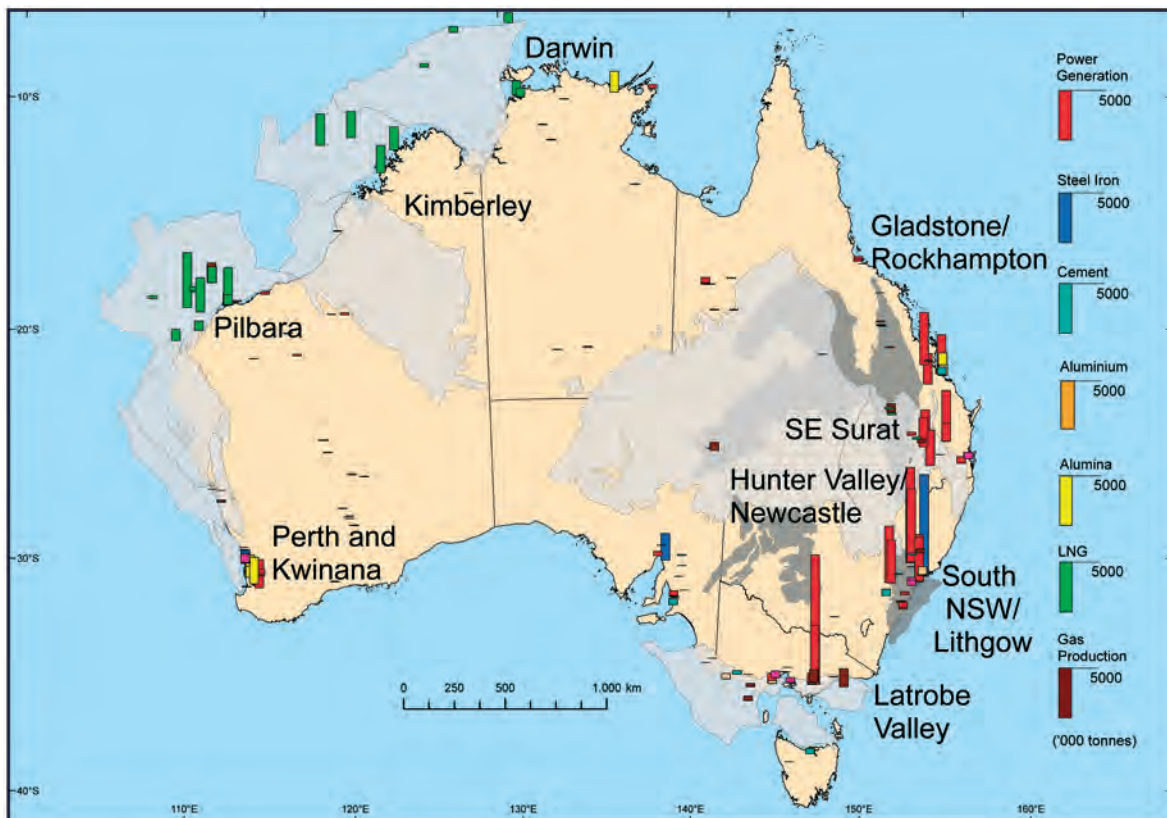
A hub provides economies of scale leading to efficient transport to, and storage in, large CO₂ geological storage sites. Complex commercial agreements will be required, however, and government could consider its role in facilitating these.

Projected emissions from stationary emitters, assuming a 10% emissions reduction target, are 277 Mt CO₂ in 2010. Electricity generation from black coal, brown coal, and gas are projected to make up 70% of this total. Emissions from power generation are projected to decrease by 2020 due to fuel switching from coal to gas and increased use of renewable energy under the Mandatory Renewable Energy Target (MRET) scheme. However, total emissions are projected to be steady to 2020, largely due to increasing LNG-related emissions from new LNG developments.

Emissions associated with LNG production come from two main sources – reservoir CO₂ that naturally occurs associated with hydrocarbon gasses in the geological reservoir, and CO₂ generated by combustion of fuel in the production and liquefaction of LNG. Reservoir CO₂ emissions are projected to increase from 2.8 to 23.8 Mtpa between 2010 and 2020. Reservoir CO₂ can be captured by well established chemical processes. The Gorgon Project¹⁹ is expected to commence storing 3.5 Mtpa of reservoir CO₂ from around 2015.

CO₂ emissions from the production and liquefaction of LNG are projected to increase from 6.6 to 29.9 Mtpa in 2020. However, capturing CO₂ associated with upstream processing and liquefaction is more problematic as LNG liquefaction plants have many sources of emissions making capture difficult. Therefore, it is likely that the most effective way to reduce emissions from liquefaction of LNG is through improving the energy efficiency of the process, rather than capturing its emissions.

Figure 11: Geographical distribution of emissions by industry estimated for 2020



(Note: grey shaded areas indicate limits of sedimentary basins)

¹⁹ www.gorgon.com.au

Figure 12: Projected CO₂ emissions by hub and industry in 2020

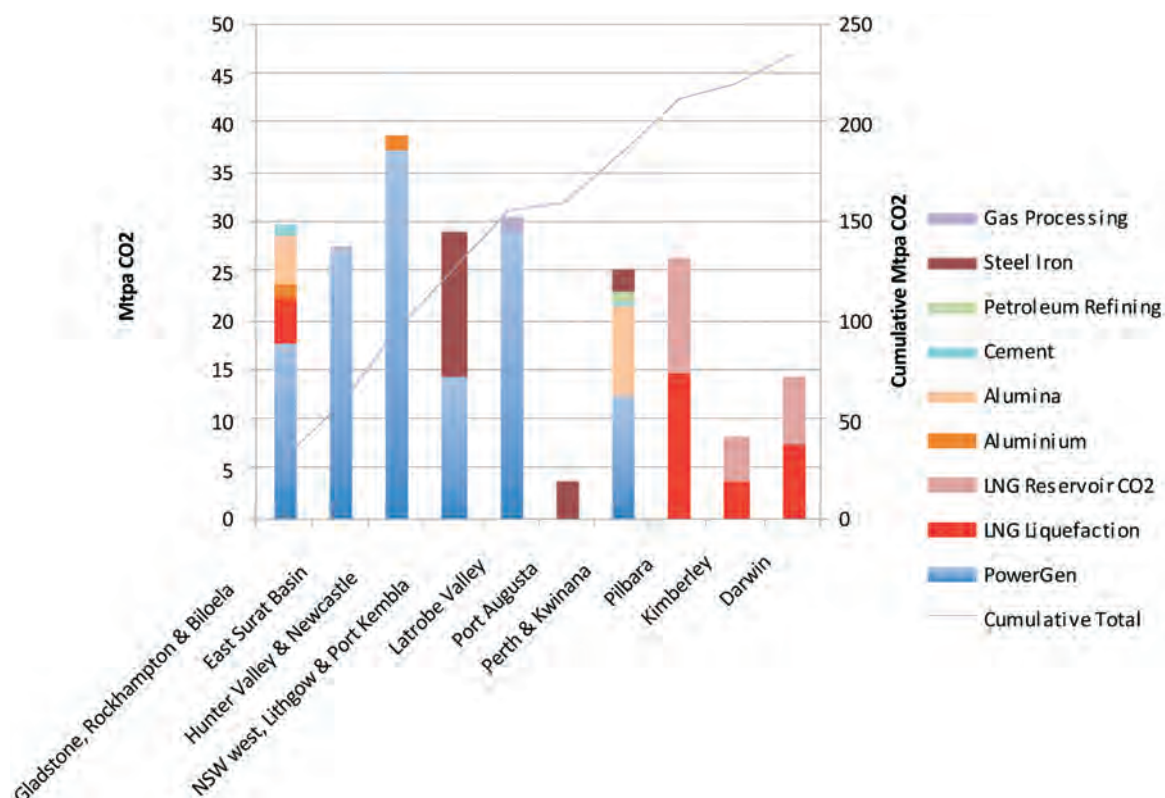


Figure 12 above shows that the largest emitter is the Hunter Valley-Newcastle hub, which produces 38.7 Mt in 2020 mainly from coal-fired power generation. Total emissions from hubs are dominated by emissions from power generation (65%), LNG (21%) and to a lesser extent alumina (7%). The most diverse hubs in terms of industries are the Gladstone-Rockhampton-Biloela, and Kwinana hubs. The Pilbara, Kimberley and Darwin hubs are entirely LNG-related. These ten hubs account for 210.8 Mt or 76% of stationary emissions in 2020.

The emissions projections for each of these locations for each of 2010, 2015 and 2020 are set out in Table 1 below.

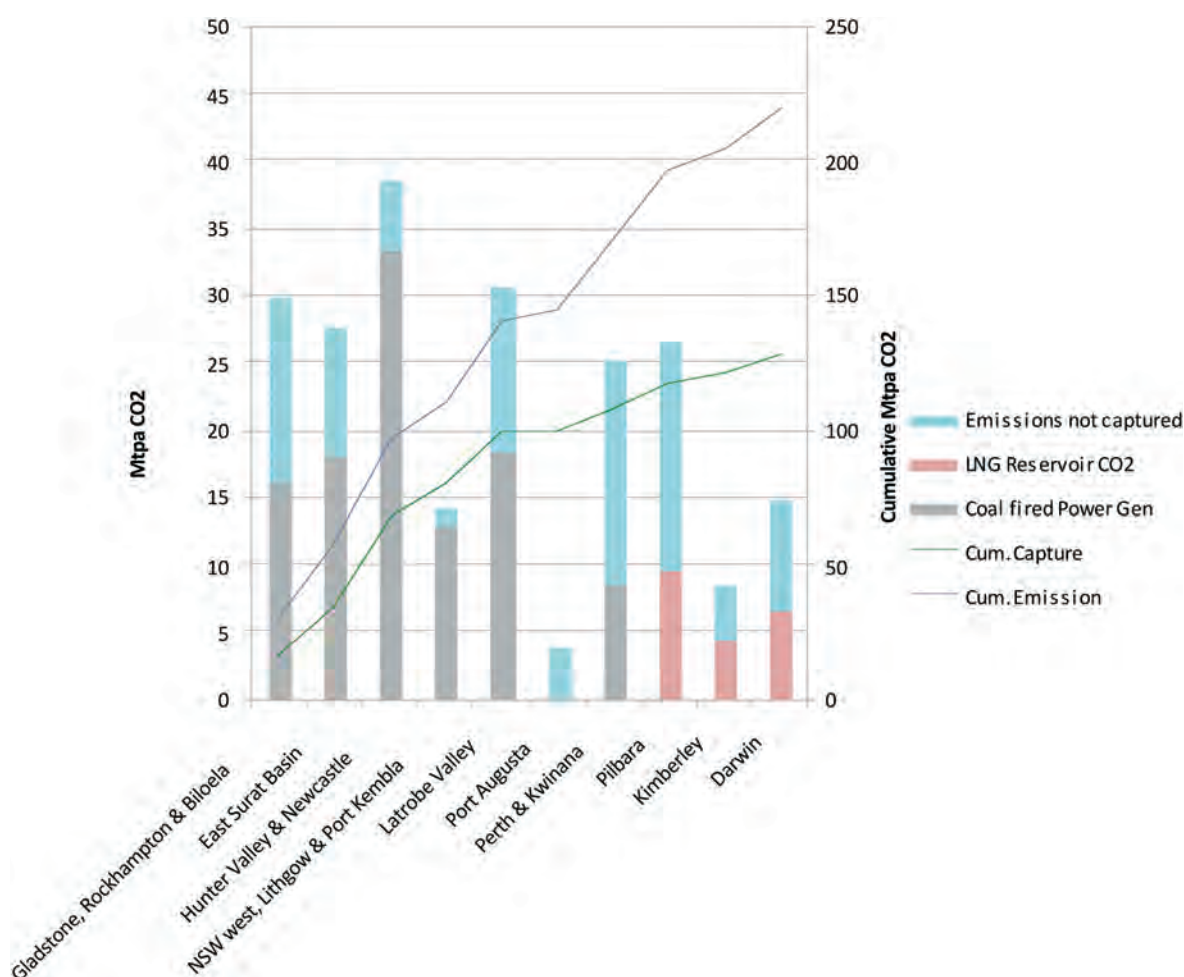
Table 1: Total emission projections by key location and year ('000 tonnes)

LOCATION	2010	2015	2020
Gladstone, Rockhampton and Biloela	31,687	32,532	29,792
East Surat Basin	23,287	24,649	27,540
Hunter Valley and Newcastle	44,763	40,616	38,721
NSW west, Lithgow and Port Kembla	28,432	28,837	29,086
Latrobe Valley	60,631	44,391	30,603
Port Augusta	8,963	7,772	3,842
Perth and Kwinana	27,878	25,420	25,139
Kimberley	0	0	8,520
Pilbara	7,661	13,982	26,527
Darwin	1,739	8,839	14,286
Total Key Sites	235,041	227,039	234,056

While the amount of CO₂ captured in future will be determined by individual project economics, an estimate of the potential volume of emissions that could be captured from hubs has been made, using the following assumptions:

- 90% of emissions from coal-fired power generation can be captured;
- nearly 100% of emissions from reservoir gas for LNG can be captured; and
- zero emission capture from gas-fired power generation, steel iron, alumina, aluminium, concrete and gas processing.

Figure 13: Emitted and captured emissions by hub in 2020



On the assumed basis, some 58% (or 123 Mt in 2020) of emissions from the ten hubs could be captured for transport and underground storage. This quantity represents 21% of total Australian greenhouse gas emissions in 2006²⁰ across all sectors (energy, industrial processes, agriculture, waste, land use, forestry) when compared against 2006 levels (576 Mt CO₂e). Other single point sources, such as those generated in the manufacture of steel, cement, and fertiliser, may also be able to contribute to the available emissions at each hub.

²⁰ Department of Climate Change 2006, *National Greenhouse Gas Inventory 2006*, Department of Climate Change, Canberra. Note: emissions data for 2007–8 not yet published.

3 CCS TECHNOLOGIES

3.1 OVERALL CONCEPT AND TECHNOLOGIES

The essence of CCS is to capture the CO₂ being emitted from a stationary source, transport it to a suitable storage location and place it within the geological storage structure. The stationary source could involve CO₂ as a by-product from oil or gas production, the processing of gas to produce Liquefied Natural Gas (LNG), the production of electricity through combustion of carbonaceous fuels, or an industrial process such as chemicals, steel or cement manufacture. In the case of oil extraction, the CO₂ injection can provide a beneficial function by enhancing the extraction of the oil from the sub-surface rock reservoirs.

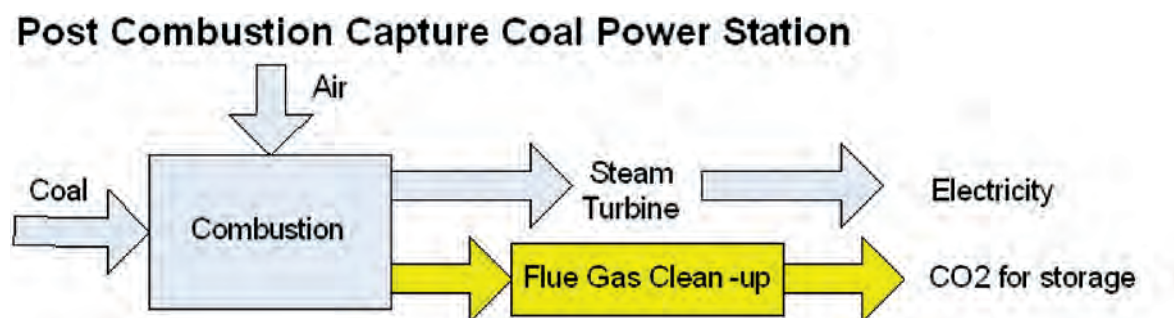
As shown in Section 2 above, the major source of CO₂ in Australia from stationary sources is from electricity production. In the future, the major hubs for CCS will be associated with this application in eastern Australia, while CO₂ storage from LNG operations will occur in western Australia.

For electricity generation, technologies for fuel combustion, the CO₂ capture process and the properties of CO₂ are particularly relevant to both the transport and storage CO₂.

Currently, the vast majority of Australia's electrical power is generated from black coal, brown coal and gas. The combustion of black and brown coal is currently carried out in pulverised fuel boilers at relatively low efficiency using air to burn the fuel, while gas is generally burnt in open cycle gas turbines (OCGT) at times of high electricity demand. This means that large volumes of a mixture of CO₂ and nitrogen (N₂) are produced from coal firing, together with some gaseous impurities. If CCS were used to capture most of the CO₂ from this gas mixture, large chemical engineering facilities would be required because of the large gas volumes emitted. In addition, all technologies for the capture of CO₂ from electricity generation involve significant use of energy for the process. This means that the capital and possibly operating costs of the capture part of the process are likely to be high.

Retrofitting of existing plant to capture CO₂ is possible. In this case the capture process is termed 'post-combustion', as shown in Figure 14.

Figure 14: Post-combustion capture process



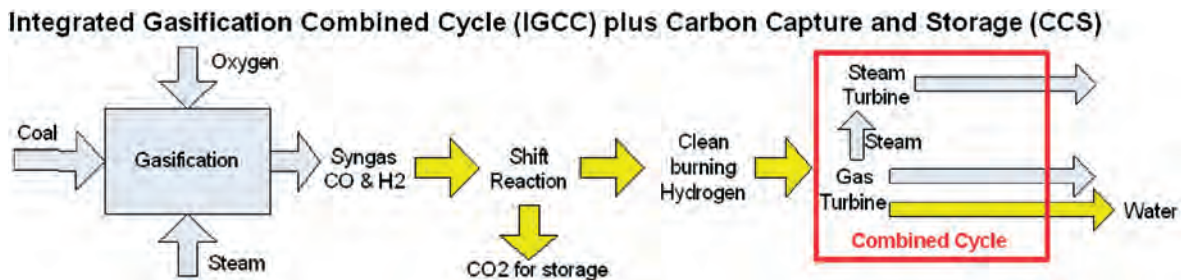
In order to improve the efficiency of both combustion and capture, new technologies for fuel combustion are under development or have been designed.²¹

One approach known as pre-combustion capture involves the partial combustion of gas with oxygen (O₂) to form a mixture of carbon monoxide (CO), hydrogen (H₂) and CO₂. This gas can be further processed with steam (H₂O) to form a mixture comprising mainly H₂ and CO₂. The CO₂ can be removed using chemical engineering techniques to produce mainly H₂ as a gas. This gas, suitably conditioned with N₂, can be burnt in a gas turbine to generate power, and the hot off-gases can be used to produce steam to drive a second turbine, thus increasing efficiency. If natural gas is used, the fuel is in a gaseous

²¹ <http://www.zerogen.com.au/project/overview.aspx>

state at the start. However, if coal is used, it must be gasified in a complex reactor system before the overall process using O_2 as the gasifying agent. This electricity generation system is termed Integrated Gasification Combined Cycle or IGCC. This process is shown schematically in Figure 15 below.

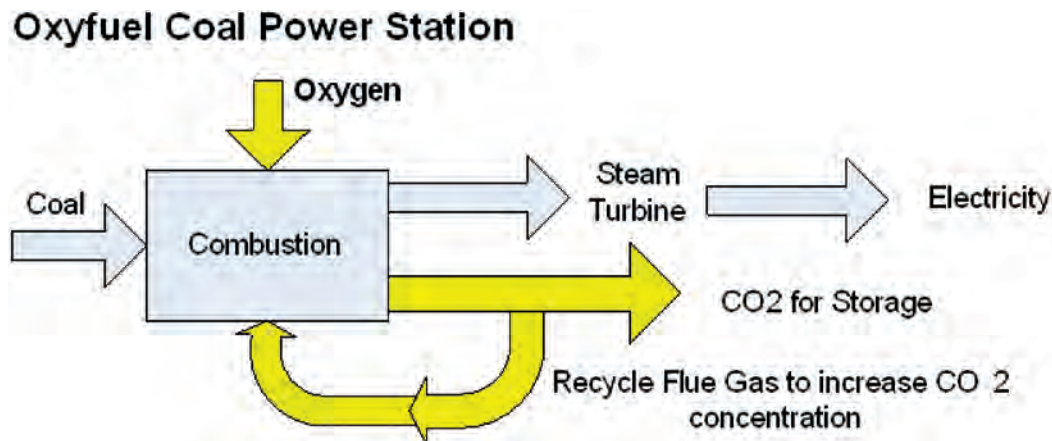
Figure 15: IGCC pre-combustion capture process



In the case of brown coal that contains combined moisture at high levels, the coal can be dried prior to gasification using the hot gases produced. In this case the process is termed 'Integrated Drying and Gasification Combined Cycle' or IDGCC.²²

Another proposed approach to increasing efficiency is known as 'oxy-fuel' and involves removing N_2 from the system in a more conventional boiler system.²³ In this case the coal would be burnt with a mixture of recycled flue gas (mainly CO_2) and O_2 at the pressurised boiler, which itself could be high efficiency producing supercritical steam at high pressure. The gases would flow through the furnace and be collected at the top, and some of the CO_2 would be recycled through the coal grinding equipment to the burners, where O_2 would be added to the recycle stream. Most of the rest of the CO_2 , with some impurities, would be captured in the chemical engineering plant downstream. This process is shown schematically in Figure 16 below.

Figure 16: Oxy-fuel capture process



In the case of both 'pre-combustion' and 'oxy-fuel' technologies, an O_2 plant will be required. However, the volumes of gas to be treated in the capture part of the facility would be less than that for 'post-combustion'. It is also important to note here that the gas compositions resulting from these different technologies, including gas firing, are different and contain different levels of impurities.

²² <http://www.australiancoal.csiro.au/pdfs/Johnson%20Pleasance.pdf>

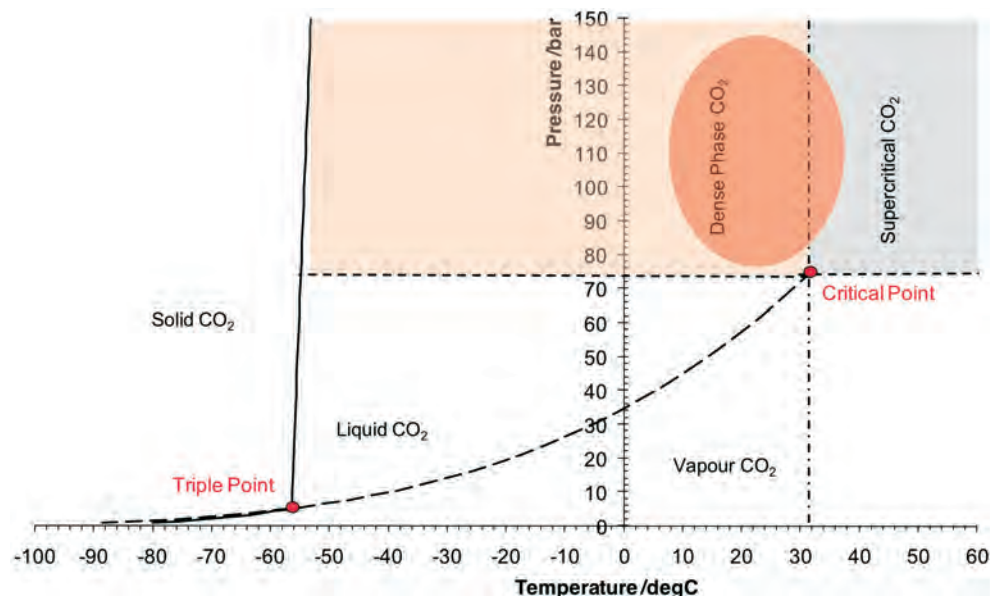
²³ <http://www.callideoxyfuel.com/What/CallideoxyfuelProject.aspx>

3.2 IMPORTANT CO₂ PROPERTIES

The properties of CO₂ differ from those of hydrocarbon gases such as natural gas. It is important to understand these properties, since they influence many aspects of its transport and storage.

At normal temperatures and pressures CO₂ is a colourless, odourless gas, which is heavier than air (density of 1.872 kg/cubic metre). However, in order to store CO₂ in geological strata it must be compressed to high pressure as a fluid. Under these conditions, CO₂ exhibits important phase changes²⁴ These are shown in Figure 17 below.

Figure 17: Phases of CO₂ at different temperatures and pressures



As can be seen from Figure 17, at temperatures greater than 31.1 °C and pressures greater than 7.38 Mpa (~73 atmospheres), CO₂ is in the 'supercritical' state. In this state CO₂ behaves like a gas in terms of its viscosity and ability to fill pores in a geological structure, but has a liquid-like density that increases depending on pressure and temperature, from 150 to 700 kg per cubic metre. Thus, for example, CO₂ stored at a depth of 1000 metres will have a volume of only about 1/300th of that which it would have as gas at the surface.

At temperatures and pressures below the critical point, CO₂ is either a liquid or a gas, depending on conditions. The higher the density, the more efficiently the CO₂ can fill the pore space in the sedimentary rock. At a given temperature, CO₂ density increases with higher pressure. Conversely, at a given pressure, the higher the temperature, the lower the CO₂ density. Moreover, both these relationships under supercritical conditions exhibit significant non-linearity.

It is desirable to compress CO₂ so that it is in the supercritical state for both transport and storage. This is because as a supercritical fluid it has transport properties (e.g. viscosity) like a gas, but has a density like a liquid and so occupies far less volume than when in a gaseous state. To maintain supercritical conditions the CO₂ must be maintained at high pressure so pipelines must be designed for this duty. As CO₂ flows along a pipeline there are pressure losses, so long pipelines will require re-compression of the CO₂ at designated spacing to maintain conditions above the critical point. This is a relatively energy-intensive and costly operation. Also, the CO₂ must be injected into storage locations at a suitable depth to maintain supercritical conditions underground. Depending on sub-surface reservoir conditions, this will be greater than around 800m depth, depending on geothermal temperature gradients.

²⁴ Race, J, Presentation to APIA, Melbourne, 4 June 2009. School of Marine Science and Technology, University of Newcastle UK.

In addition to the general non-linearity of the pure CO₂ phase diagram, research has shown that minor impurities in the CO₂ can significantly affect the supercritical regions.²⁵ It has been found that the type of combustion process (discussed in Section 3.1 above) can affect the level of these gaseous impurities and hence the temperatures and pressures where the supercritical phase of the CO₂ mixture exists. These issues will be discussed further in the transport and storage sections of the report below.

3.3 CO₂ STORAGE

3.3.1 Introduction to Geology

The geological storage of CO₂ has analogies with natural accumulations of petroleum (oil and natural gas) and other gases, such as CO₂ and helium, which are trapped in the subsurface.

The simplest CO₂ storage involves injection into a depleted oil or gas field to occupy the pore space, which previously contained the produced fluid. In such cases, a CO₂ containment mechanism may be proven by the presence of petroleum. In certain oil fields, CO₂ injection can be done, before the field is totally produced, to help extract oil that would otherwise have been unrecoverable. This is known as Enhanced Oil Recovery (EOR). However, in EOR, much of the injected CO₂ is reproduced with the oil, and thus only part of the CO₂ is permanently stored.

In other cases the CO₂ may be injected into the body of the reservoir rock below the zones where oil or gas may be trapped or into rock formations where oil and gas do not occur. These formations, which are normally filled with salt water or brines, are generally termed deep saline reservoirs or aquifers. It is in these formations that the greatest storage potential is considered to lie. The CO₂ is trapped in these deep saline aquifers by a variety of natural processes that are well researched and understood. These processes include physical trapping against an impermeable layer, dissolution into the saline formation water, residual trapping by relative permeability and capillary pressures, and re-deposition as newly-formed minerals.

Other trapping mechanisms such as injecting into deep un-minable coal seams or chemical trapping by injection into reactive rocks such as serpentinite have also been proposed for geological storage, but these are much less understood and more speculative and are therefore not considered in this report.

3.3.2 Current International Projects and Experience

There are a number of international projects currently underway on CCS. These include the Sleipner and Snohvit projects in Norway, the In Salah project in Algeria, the Weyburn project in Canada and the CO2CRC Otway Basin project in Victoria, Australia. A brief summary of these projects is given to provide context for the report.

Sleipner

The Sleipner project is in the Norwegian North Sea about 250km off the coast. CO₂ contained in natural gas from the Sleipner East gas field is separated from the gas stream on the offshore production platform and then injected into the thick Utsira Formation, between 800m and 1000m below the seabed. The project has been injecting about 1 Mt per year since 1996 and is expected to last 20 years. Monitoring of the subsurface movement of the CO₂ plume is carried out by 4D seismic methods.²⁶

Snohvit

The Snohvit project is a follow-on from the Sleipner project. Gas from the Snohvit, Albatross and Askeladd fields in the Barents Sea north of the Arctic Circle, about 140km northwest of Hammerfest, is piped to the island of Melkoya. The CO₂ is stripped from the gas stream there and piped back to

25 Race, J, Presentation to APIA, Melbourne, 4 June 2009. School of Marine Science and Technology, University of Newcastle UK.

26 4D seismic refers to the technique of running a series of repeated conventional 3D surveys over an extended period of time, for instance every two years, during the course of the project to be able to monitor the changes in the seismic response due to the injection of the carbon dioxide and thus map the progress of the plume.

the field for injection into a Jurassic sandstone, which lies below the reservoir formation in the field. CO₂ capture and storage began in 2009 and at injection rates of 700,000 tonnes per year.

In Salah

The In Salah project, operated by BP, is located in the central Saharan region of Algeria. The project is an industrial-scale demonstration of CO₂ storage, with no commercial benefit to the operator. Natural gas in the Krechba field contains about 10% CO₂, which is stripped from the gas stream at the processing site located above the field. The CO₂ is injected into the same reservoir unit from which it is extracted. The project commenced injecting in 2004 and currently injects about 1.2 Mt per year. The project is expected to have a life of about 25 years and store 17 Mt of CO₂.

Weyburn

The Weyburn project, operated by EnCana, is located in the Williston Basin, Saskatchewan, Canada. The project is an enhanced oil recovery operation using CO₂ from a gasification plant in North Dakota, USA to recover additional oil from a large oil field that was in decline. It will also act as a storage project by eliminating the CO₂ because a significant amount of CO₂ will be left trapped at the end of the field life. The CO₂ is stored in a carbonate reservoir. Injection started in 2004 and is expected to continue for 20 to 25 years. Injection rates to 1.8 Mt per year are expected over the life of the project and the total amount of CO₂ stored is expected to be around 20 Mt.

Otway Basin

The Otway Basin project in western Victoria is operated by the storage research group of the CO₂CRC²⁷ and is a demonstration project. It involves the extraction of naturally occurring CO₂ from a small nearby accumulation and piping this CO₂ approximately 2km to a small, depleted gas field in the Waarre Sandstone where it is injected at a depth of around 2000m. Injection at a rate of 150 tonnes per day started in April 2008 and, at the end of Phase 1 in mid-2009, 65,000 tonnes had been injected. A second phase of the project has commenced that will involve injecting small volumes of CO₂ into a higher reservoir, the Paaratte Formation. The CO₂CRC project is a research demonstration project and, as such, involves extensive monitoring of the containment of the injected CO₂.

27 www.co2crc.com.au

4 AUSTRALIA'S STORAGE POTENTIAL

The IEA²⁸ considers that the storage of CO₂ in aquifers, depleted oil and gas fields, and the use of CO₂ for enhanced oil recovery (EOR) are proven storage options. The Taskforce has therefore evaluated the carbon storage potential of depleted oil and gas fields and aquifers in Australia.

A good storage basin is one where a potential reservoir rock with an overlying seal lies at depths of between 800 and 2000m to allow the CO₂ to be stored in the supercritical phase. Typically reservoir rocks will be sandstones or carbonates and the seals will be shales. In general, the basins will not be excessively faulted or extensively tectonised.²⁹ However, gentle folding, especially if it produces a network of anticlinal closures³⁰ at the base of the seal, may be an advantage.

Basins which are known petroleum-producing provinces are likely to be the best for the storage of CO₂ because they have proven reservoirs and seals and are generally well explored, and therefore have an existing database of geological information. However, in some cases they may present challenges if extensively faulted. Non-producing basins may also have potential if the lack of petroleum is due to the absence of source rocks. However, they will generally be much less known and will require more exploration effort and data gathering before their potential can be properly assessed.

Given the timeframe set by the Terms of Reference and wide scope of the assessment, capacity estimates derived by the Taskforce were based on an extensive, high level, 'top down' analysis using publicly available data. Ultimately, the capacity and characteristics of each storage reservoir will require a comprehensive, 'bottom up' assessment, which will be calibrated against the monitored behaviour of injected CO₂. The top-down process used by the Taskforce is outlined below.

4.1 PROCESS FOR RANKING BASINS

Australia has many sedimentary basins, some of which are well known and explored, and others with little or no information. There are large thick basins along the north western³¹, western³² and southern margins³³ of the country. The onshore basins with significant sedimentary thickness are concentrated in the central east of Australia³⁴ with one basin in the west.³⁵

The Taskforce has therefore used a high-level, qualitative approach to ranking the basins that endeavours to account for this diversity in understanding. It is important to recognise that, in practice, every storage site will require a detailed, comprehensive assessment of the particular characteristics that will determine its capacity to store CO₂ safely and securely.

4.1.1 Creation of Basin Montages

To determine the best or optimum geological basins for the storage of CO₂, two processes were adopted in the Taskforce's analysis. The first was to score the basins based on a range of qualitative macro-criteria related to location, geology, size, knowledge base, and so on. The second was to quantitatively determine, as far as is possible, the amount of CO₂ that can be stored within each basin. Montages of the features of each basin, including geological information, ranking, CO₂ injection parameters, basin permeability and porosity and estimated probabilistic storage capacity, have been determined for each of the highly ranked basins from the two components of the work. The process for determining each of these is discussed below.

28 International Energy Agency, 2008, *Energy Technology Perspectives 2008: Scenarios and Strategies to 2050*, OECD/IEA

29 Tectonised: deformed and folded by major movements in the Earth's crust.

30 Anticlinal closures: features formed by gentle folding of the sedimentary basin.

31 Bonaparte and Browse basins.

32 Carnarvon, North Perth and Perth basins.

33 Otway, Bass, Torquay and Gippsland basins.

34 Eromanga, Cooper, Bowen, Surat and Galilee basins.

35 Canning Basin.

4.1.2 Qualitative Basin Ranking

Bachu³⁶ has developed a qualitative tool based on 15 criteria for the assessment and ranking of sedimentary basins for their suitability for CO₂ storage. The series of criteria range from purely geologic criteria through possible resource conflicts, and geographic criteria, to economic criteria. Each criterion is described by a set of description classes that are translated through a weighted scoring mechanism to give an overall basin score that allows ranking of the CO₂ storage suitability of the basins. A copy of the Bachu criteria is attached in Appendix F.

For the ranking of Australian basins, Bachu's approach has been modified by the Taskforce to exclude certain criteria that are strictly commercial (e.g. coal and coal bed methane, infrastructure, accessibility, onshore/offshore location) because the carbon storage economics of each basin are calculated separately during the detailed evaluation process.

The modified Bachu criteria employed are shown in Table 2 below. The criteria include the basin's physical dimensions and properties (e.g. basin size, depth, hydrogeology, geothermal regime), its geology (e.g. depositional type, faulting intensity, reservoir quality, seal quality), its hydrocarbon potential (a good measure of seal effectiveness), and overall level of knowledge about the basin (e.g. exploration maturity, knowledge level, data availability).

The technical ranking of Australian basins was carried out by Australia's Chief Geoscientists or their staff using the modified Bachu criteria shown in Table 2. The basin scores and the evidence supporting the ranking are documented in the suite of montages. These were used to consult with a broader stakeholder group, including oil and gas companies, consultants and service providers.

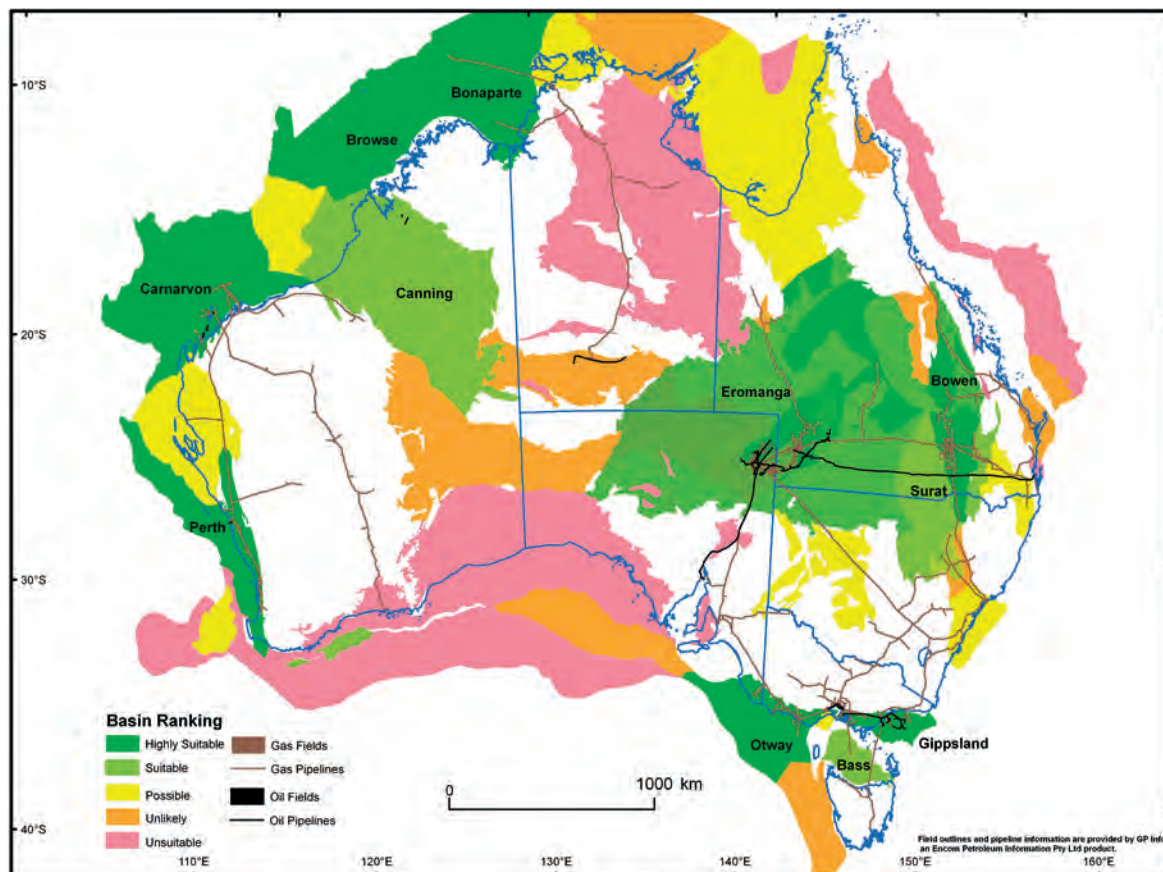
Table 2: Key ranking criteria and weighting for Australian basins

CRITERION	1	2	3	4	5	WEIGHT
Size	Small (<5000km ²)	Medium (5000–25000km ²)	Large (25000–50000km ²)	Very Large (>50000km ²)		0.04
Depth	Shallow (<1,500m)	Deep (>3,500m)	Intermediate (1,500–3,500m)			0.10
Type	Non-marine	Non-marine and marine	Marine			0.04
Faulting intensity	Extensive	Moderate	Limited			0.14
Hydrogeology	Poor (fractured rock system, short flow system)	Intermediate (faulted-fractured rock system, intermediate flow)	Good (regional, long-range flow systems; topography or erosional flow)			0.04
Geothermal	Warm basin (>40°C/km)	Moderate (30–40°C/km)	Cold basin (<30°C/km)			0.05
Hydrocarbon potential	None	Small	Medium	Large	Giant	0.05
Maturity	Unexplored	Exploration	Developing	Mature	Over-mature	0.05
Reservoir	None	Potential	Poor	Good	Excellent	0.16
Seal	None	Potential	Poor	Good	Excellent	0.18
Reservoir/Seal Pairs	None	Poor	Good (Single)	Excellent (Multiple)		0.03
CO ₂ sources	None	Few	Moderate	Major		0.00
Knowledge level	Limited	Moderate	Good	Extensive		0.06
Data availability	Poor	Moderate	Good	Excellent		0.06

³⁶ Bachu, S, 'Screening and Ranking of Sedimentary Basins of CO₂ in Geological Media in Response to Climate Change', *Environmental Geology*, 44:277-289 (2003).

The results of the Australian basin ranking are shown on a map in Figure 18 below. In this figure, the highest ranked basins are shown in green, the next in yellow, then orange, and the lowest ranked basins in pink. Basins shown in pink are considered to be unsuitable as storage basins, and those in orange are unlikely to be suitable.

Figure 18: Australia's basins ranked for CO₂ storage potential³⁷



Basins coded in the dark green are the highest ranked and regarded as being highly suitable. They also have high knowledge and data availability scores i.e. these are basins that could potentially be matured as carbon storage areas quickly. They are: Gippsland, Bowen, Eromanga, Otway, Perth, Carnarvon, Browse, Bonaparte, and Money Shoals. Other highly ranked basins (light green) are Surat, Bass, and Canning.

Basin montages (see Appendix E for an example) were created for the basins that are suitable or highly suitable, or are considered to be strategically important. For example, the NSW basins are classified as possible storage basins, but they will require further evaluation. They are strategically important because if exploration fails to prove up storage potential, major pipelines will be needed to transport CO₂ interstate.

Montages have been made for the following basins (all of which are contained on the disc attached to this report):

- Victoria: offshore and onshore Gippsland, Bass, Torquay, eastern Otway;
- New South Wales: Clarence-Moreton, Darling, Gunnedah, Sydney;
- Queensland: Surat (and Roma Shelf), Bowen, Denison Trough, Gallilee;
- Queensland/South Australia: Eromanga, Cooper;
- Northern Territory/Western Australia: Bonaparte;

³⁷ The mismatch of colours in the basin ranking map (Figure 18) with the basin ranking classes in the map legend in the Eromanga and Surat basins region, is due to the presence of underlying sedimentary basins.

- Western Australia: northern and southern Carnarvon, onshore and offshore Canning, Browse, onshore and offshore North Perth, Vlaming;
- South Australia: western Otway.

4.2 OIL AND GAS FIELD STORAGE

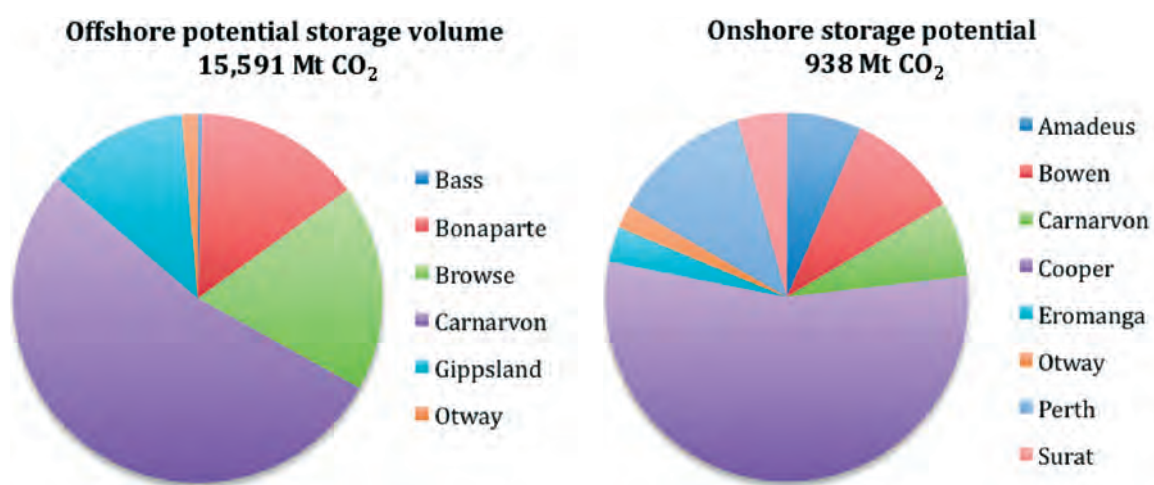
The majority of Australia's oil reserves are located offshore Western Australia in the Carnarvon Basin and in the Gippsland Basin, offshore Victoria. Australia has experienced decreasing oil production due to natural declines in oil-producing basins such as Cooper-Eromanga and Gippsland, as well as a lack of new fields coming on line.

The bulk of Australia's gas resources are located long distances from the eastern Australian markets. These are in the offshore of northwest Western Australia (Carnarvon and Browse basins) and in the Timor Sea to the north of Australia (Bonaparte Basin). Gas fields have been developed in the Gippsland, Bass and Otway basins located offshore in southern Victoria. There has been rapid development of coal seam gas reserves in Queensland and New South Wales. These have the potential to become a major source of gas in eastern Australia.

The Petroleum and Greenhouse Gas Advice Group of Geoscience Australia, in advice provided to the Taskforce, has estimated the potential storage of CO₂ for existing oil and gas reservoirs for each significant Australian petroleum basin. This is as distinct from the estimated storage capacities of the saline aquifer basins, below. The likely timing of availability of these reservoirs, which arises because CO₂ injection could compromise petroleum production, has also been examined.

While the majority of the storage potential lies in aquifer storage, the CO₂ storage capacity of oil and gas fields in Australia has been estimated to be approximately 16.5 gigatonne (Gt). The vast majority of this storage is offshore (~15.6 Gt). The northwest of Australia contains ~13.4 Gt of storage capacity, but these fields are distant from the emitters in southwest Western Australia and eastern Australia and depletion is many years away. Figure 19 below shows the storage potential of onshore and offshore oil and gas reservoirs by basin determined by this investigation.

Figure 19: Onshore and offshore storage potential of CO₂ in all Australia's oil and gas reservoirs by basin



The Bowen and Surat basin gas and oil reservoirs in Queensland are well placed to match local small volume CO₂ sources. Most oil and gas reservoirs in this area are in an advanced stage of depletion so a CO₂ storage project could have progressive access to a series of depleted reservoirs over time. There may be competing interests where depleted reservoirs would also form an ideal storage buffer for coal seam gas (not CO₂) extracted for use in the proposed LNG projects.

There is significant storage potential in the Gippsland Basin where several oil fields appear to be at or near the end of their productive life. These have potential to hold significant volumes of CO₂ but the transition from petroleum recovery to storage activities needs to be carefully managed.³⁸ The larger gas fields have productive lives that could extend beyond 2050.

There appears to be only limited potential for the use of CO₂ to enhance oil recovery in Australia, and this activity appears unlikely to result in significant storage. However, it could be an important driver of early projects since it generates revenue through the sale of the additional hydrocarbons recovered, thereby offsetting costs. The net impact on emissions after considering the end use of the additional fossil fuels recovered needs to be also taken into account.

The depleted and near depleted gas and oil fields of the Bowen and Surat basins are well placed to match local small volume CO₂ sources. There is significant storage potential in the Gippsland Basin where some oil fields appear to be near the end of their productive life.

4.3 AQUIFER STORAGE

Some of Australia's many basins are well explored and knowledge of the basin's geology is high. Others are relatively unexplored, with little knowledge and data on them.

The Taskforce used a high-level, qualitative approach to ranking the basins to account for this diversity. Eleven basins are regarded as having the best potential for storage – Gippsland (Vic), Bass (Vic/Tas), Bowen (Qld), Surat (Qld), Eromanga (SA/Qld), Otway (Vic/SA), Perth (WA), Carnarvon (WA), Browse (WA), Canning (WA) and Bonaparte (WA/NT). A further series of basins have been identified as having possible storage potential or are of strategic importance.

These highest ranking basins determined from the modified Bachu process were analysed by a Taskforce workgroup to determine, as far as is possible, the CO₂ storage capacity of the basin saline aquifer. A probabilistic analysis was employed to handle the inherent uncertainty in the analysis, in a similar fashion to processes employed in the petroleum industry. The process employed is described below and the data employed in each basin to undertake the analysis is presented in detail in the developed montage for each basin. The process was coordinated by Geoscience Australia. An example of a developed basin montage is given in Appendix E for the Gippsland Basin.

The key input parameters for the storage analysis follow.

- *The area of the storage region* – this was typically estimated using maps of depth from the surface to the base seal, where the base seal is deeper than 800m from the surface (as described in Section 3 above, 800m is approximately the depth below which CO₂ would remain as a supercritical fluid). The area analysis also took into account uncertainty about sealing potential and the possibility of fault breaching.
- *The gross thickness of the saline reservoir formation* – this was typically derived from well penetrations in the basin. In the analysis, the formation thickness plus the depth of the base of the seal was used to estimate injection depths for the CO₂.
- *The average porosity of the saline formation over the thickness interval* – this was typically derived from well core data. Note that in the analysis this parameter was the average porosity over the thickness interval and included good and poor sands.³⁹
- *The density of CO₂ at average reservoir conditions* – a range was used to account for the average depth, average pressure and average temperature effects in the reservoir.

38 RISC 2009, *Gippsland Basin – Availability Projections for Carbon Storage*, report prepared for the Carbon Storage Taskforce, Department of Resources, Energy and Tourism, Canberra

39 Reference to 'sands' in this report in the context of CO₂ storage means porous sandstone at depth beneath an impermeable rock seal. The calculated average porosity parameter is distinct from the porosities tabulated under 'Injection Parameters' on the montages, which are biased towards injection into the better porosity/permeability sands.

- *E*, the storage efficiency factor – a single number of 4% was assumed for *E* in the montages. The storage efficiency factor is the fraction of the total pore volume that will be occupied by CO₂. This value is not well known, and it may vary considerably depending on geology. Estimates for saline aquifers tend to be in the range of 0.5% to 4%⁴⁰, which is almost an order of magnitude of uncertainty. In the estimations of storage capacity that follow, both an efficiency factor of 4% and an efficiency factor of 0.5% have been used.

Each of the parameters in the analysis was described by a probability distribution, characterised by a 'proven' (90% probability), a 'most likely' (50% probability) and a 'possible' (10% probability) estimate and a distribution shape. In cases where very little is known, the shape of the distribution was assumed to be boxcar (i.e. all random samples are equi-probable). With increasing confidence, a triangular distribution was used, and a normal distribution was used where the parameter could be confidently characterised.

The amount (tonnes) of CO₂ that can be stored in any given basin was calculated by the area of the basin, times its depth, times its porosity, times the density of CO₂ at the appropriate conditions, times the assumed storage efficiency. Using this approach, the parameters describing each basin's storage characteristics have been combined in Monte Carlo simulations to derive probabilistic estimates of each basin's storage capacity. These data are shown in each basin montage at the 90%, 50% and 10% confidence levels for *E*=4% and *E*=0.5%. Using this technique, Australia's CO₂ storage capacity (50% confidence⁴¹) is estimated to be 417 Gt, assuming a storage efficiency factor (*E*) of 4%, as shown in Table 3.

40 US DoE: *Carbon Sequestration Atlas of the United States and Canada* (2008). To calculate storage capacity using *E*=0.5%, the capacity calculated on the basin montages would be divided by 8 relative to a value of 4%.

41 Storage capacity estimated using a probabilistic approach as used in petroleum resource estimation. '50% confidence' indicates that there is at least a 50% probability that the storage capacity actually able to be utilised will equal or exceed the estimate.

Table 3: Estimated storage capacities of Australian basins, ranked according to capacity for E=4%

BASIN NAME	CAPACITY (GIGATONNES)			RANKING	
	P10	P50	P90	SCORE	RANKING
Gippsland – offshore	30.1	51.0	80.3	0.91	1
Eromanga – SA	11.6	26.8	52.5	0.80	2
Carnarvon – North ⁴²	25.5	48.5	89.3	0.78	3
Browse	7.0	11.3	16.3	0.73	4
Cooper	4.1	7.9	14.7	0.68	5
North Perth – offshore	12.2	26.4	45.3	0.67	6
Bowen	1.6	3.3	5.9	0.66	7
Otway – East	8.4	14.5	21.0	0.64	8
Roma Shelf	0.1	0.1	0.2	0.64	9
Vlaming	0.2	0.3	0.4	0.64	10
North Perth – onshore	1.4	2.9	5.3	0.63	11
Bonaparte – NT ⁴³	32.2	55.3	88.0	0.62	12
Galilee	7.5	14.0	21.9	0.62	13
Canning – onshore	16.5	33.3	59.8	0.61	14
Bass	12.7	19.1	26.1	0.61	15
Denison Trough	1.7	3.0	4.9	0.59	16
Surat	6.1	10.3	16.1	0.59	17
Darling	2.6	7.2	16.4	0.58	18
Otway – West	4.5	11.0	23.7	0.58	19
Gippsland – onshore	0.7	1.0	1.4	0.57	20
Torquay	1.6	2.2	2.9	0.56	21
Canning – offshore	23.5	37.7	56.0	0.55	22
Clarence-Moreton	2.9	5.5	10.2	0.51	23
Carnarvon – South	11.1	22.8	40.1	0.50	24
Sydney	0.4	0.8	1.6	0.50	25
Gunnedah	0.4	0.8	1.6	0.42	26
TOTAL	226.6	417.0	701.9		

The storage efficiency factor is not well known, and it may vary considerably depending on geology. It is known that the CO₂ will move preferentially through the more porous and permeable zones within the body of the rock, but to date there is not enough empirical evidence to determine how much of a given formation the moving fluid will actually fill during a storage operation. Estimates for aquifers tend to be in the range of 0.5% to 4%. The proven (90% confidence⁴⁴) cumulative storage capacity is between 33 Gt (E=0.5%) and 226 Gt (E=4%).

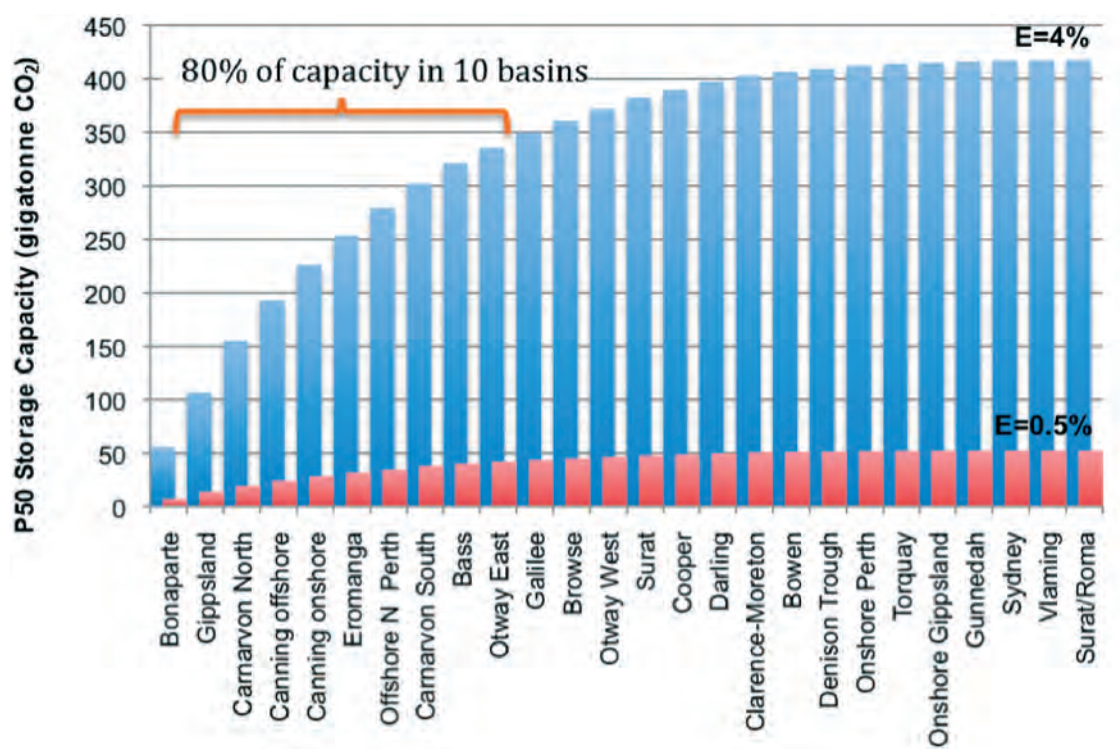
42 The calculation of capacity for the northern Carnarvon Basin is based on the Barrow Sub-Basin.

43 The calculation of capacity for the Bonaparte NT is based on the Petrel Sub-Basin. A separate calculation for the W.A. portion of the basin is available on the Basin Montages disc.

44 'Proven' used where there is at least a 90% probability that the storage capacity is actually able to be utilised will equal or exceed the estimate.

Figure 20 below shows estimated storage capacities of Australian basins at the 50% confidence level for $E=0.5\%$ and $E=4\%$. As can be seen, 80% of capacity is contained in 10 key basins. This figure, and Figure 21 which follows, shows that there is high confidence that the east of Australia has aquifer storage capacity for between 70 and 450 years at a storage rate of 200 Mtpa, and that the west of Australia has capacity for between 260 and 1120 years at a rate of 100 Mtpa.

Figure 20: Estimated storage capacities of Australian basins (p50 confidence level)

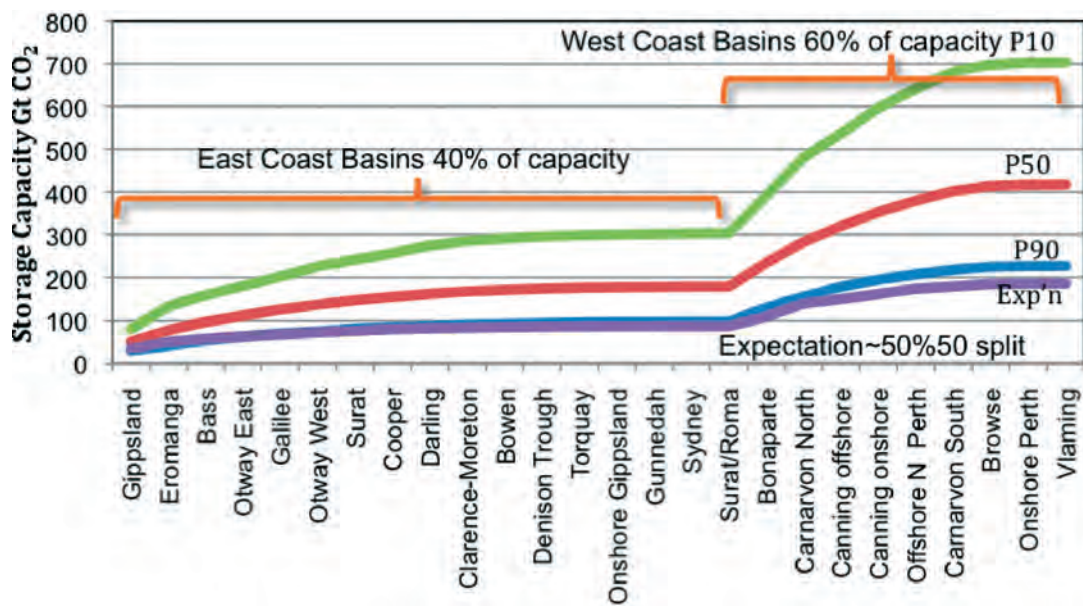


The cumulative Australian storage capacity at the 50% confidence level is 417 Gt for a storage efficiency factor of 4%. This is equivalent to around 2000 years of injection at 200 Mt per year. For a storage efficiency factor of 0.5%, the storage capacity would be reduced to 50 Gt, or 260 years of injection at 200 Mt per year.

Figure 21 shows the cumulative capacity for '90%', '50%' and '10%' probabilities (in oil and gas terms: 'proven', 'probable' and 'possible' capacity) sorted in terms of east- and west-coast basins.⁴⁵ This result is important, since it shows that while most of the potential storage capacity is on the west coast, most of Australia's stationary emission sources are located on the east coast.

⁴⁵ In Figure 21, the p90, p50 and p10 curves have been derived by simple arithmetic addition.

Figure 21: Cumulative CO₂ storage capacity assuming E=4%



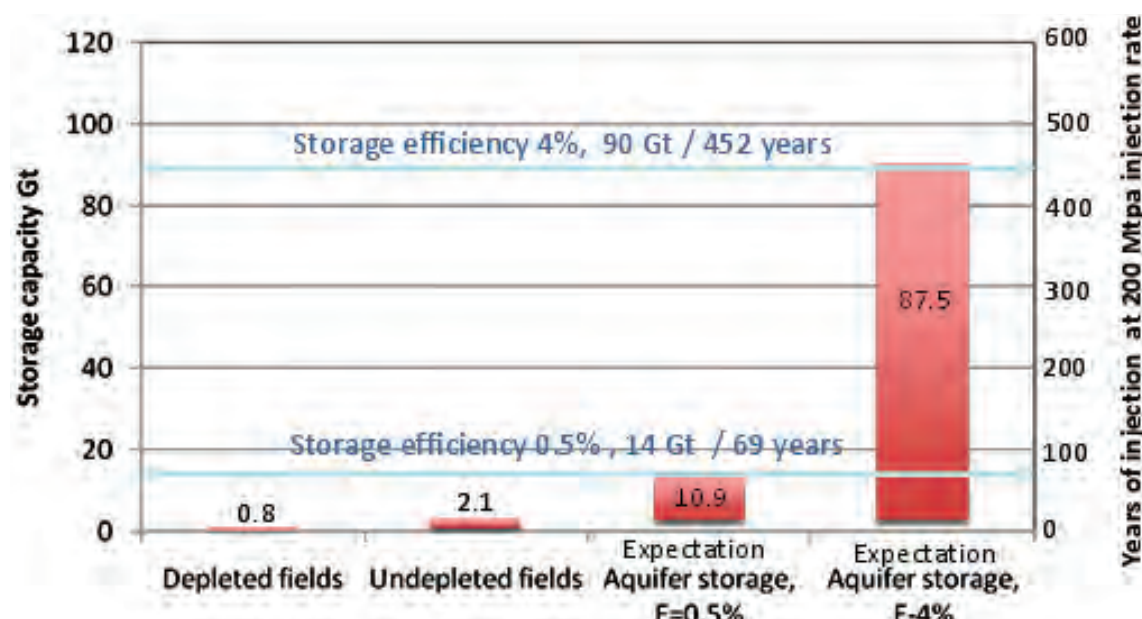
The 'proven' or 90% confidence cumulative storage capacity in all basins is between 33 Gt (E=0.5%) and 226 Gt (E=4%). An estimate of risked capacity or expectation has also been made using each basin's modified Bachu score to estimate its probability of success (see Section 10.3.4 below for a discussion of the Exploration Risk estimates). The cumulative expectation is 186 Gt (E=4%) or 22 Gt (E=0.5%). This is similar to the 'proven' estimate. This means that there is very high confidence that there is a saline aquifer storage capacity for at least 50 to 60 years of emissions at 200 Mt per year, taking all basins into account.

4.3.1 East Coast Estimates

Figure 21 shows that 40% of estimated capacity is located on Australia's east coast. The east coast cumulative capacity (at the 50% confidence level) is 178.5 Gt (at E=4%), reducing to 22.3 Gt at lower storage efficiency (i.e. at E=0.5%). This is equivalent to 485 and 61 years of CO₂ injection respectively, at a rate of 200 Mt per year for the 'probable' confidence level.

Figure 22 summarises the total field and risked (expectation) aquifer storage capacity for the east coast basins. This figure shows that, for the E=4% storage efficiency case, 90 Gt of CO₂ storage is available. This represents 452 years of capacity at a rate of 200 Mt per year. At the 0.5% storage efficiency level, the expected capacity is 14 Gt, which represents 69 years at 200 Mt per year. By comparison, the 2020 forecast emissions of the east coast hubs (including Adelaide) are projected to be 145 Mt per year.

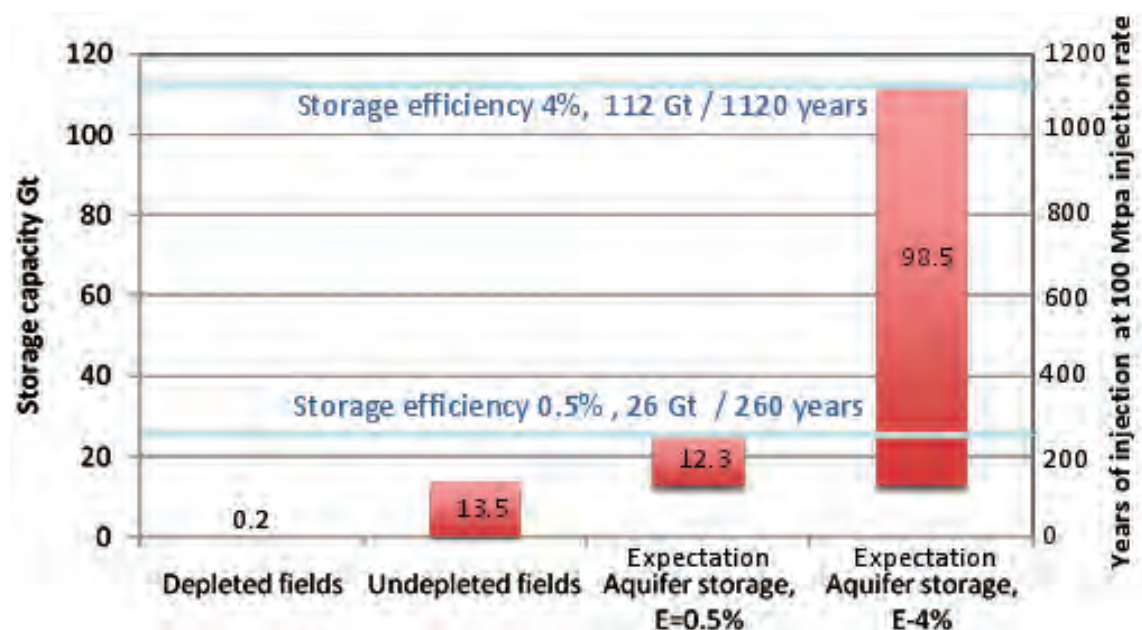
Figure 22: Eastern seaboard Australia – risked CO₂ storage capacity



4.3.2 Western Seaboard Estimates

The western seaboard hubs (including Darwin) are projected to emit 66 Mt per year in 2020. Figure 23 shows western Australian risked CO₂ storage capacity for annual emissions of 100 Mt per year. The figure shows that, for a storage efficiency of E=4%, the expected value of storage is 112 Gt. This is sufficient for 1120 years. At the lower efficiency of E=0.5%, the expected total storage is 26 Gt, or sufficient for 260 years.

Figure 23: Western seaboard Australia – risked CO₂ storage capacity



There is high confidence that the east of Australia has aquifer storage capacity for 70–450 years at a storage rate of 200 Mtpa, and that the west of Australia has capacity for 260–1120 years at 100 Mtpa, with the possibility that a far greater capacity will be defined as basins and their CO₂ storage behaviour become better known.

4.4 CALCULATION OF POTENTIAL CO₂ INJECTION PARAMETERS FOR STORAGE BASINS

The main factors affecting the economics of carbon storage are location (i.e. the distance from the CO₂ source to the storage location giving pipeline costs, and whether the location is onshore or offshore), reservoir depth (giving well costs) and injectivity parameters (notably permeability and differential pressure), which dictate the number of wells required. This information is used in later sections of the report to calculate (for example) the tariffs for CO₂ transport and the possible timing of new CCS technologies on a state-by-state basis.

To estimate the cost (and hence economics) of CO₂ transport and storage, the three representative locations in each of the top ranked basins were selected to represent a shallow, mid and deep location⁴⁶ for injection of CO₂, in order to characterise the range of possible transport and storage locations. The locations are conceptual only and represent locations in the basin that characterise a shallow, mid-range or deep reservoir depths in each basin. They do not represent targets for injection. Table 4 shows an example of the data for the Gippsland Basin.

Table 4: Example of data parameters for the Gippsland Basin at representative shallow, mid and deep locations

PARAMETER	UNIT	SHALLOW	MID	DEEP
Depth base seal	m	1600	2000	2400
Formation thickness	m	500	700	900
Injection depth	m	2100	2700	3300
Porosity	%	24	22	20.5
Permeability	mD	1400	400	125
Formation pressure	psia	3030	3900	4760
Fracture pressure	psia	5460	7010	8570
Formation temperature	°C	90	110	130

It should be noted that the data from which these parameters are derived have been collected in the exploration for oil and gas and as such, are biased toward structural anomalies within the basins. For this reason, the reservoir parameters of the deeper parts of the basin where the most extensive storage potential is believed to exist are imperfectly known and the proving up of this potential will require exploration specifically for this. There is a possibility that such exploration may encounter small accumulations of oil and gas in traps that have not been previously mapped, but it is not expected that these will be extensive in the areas selected for storage.

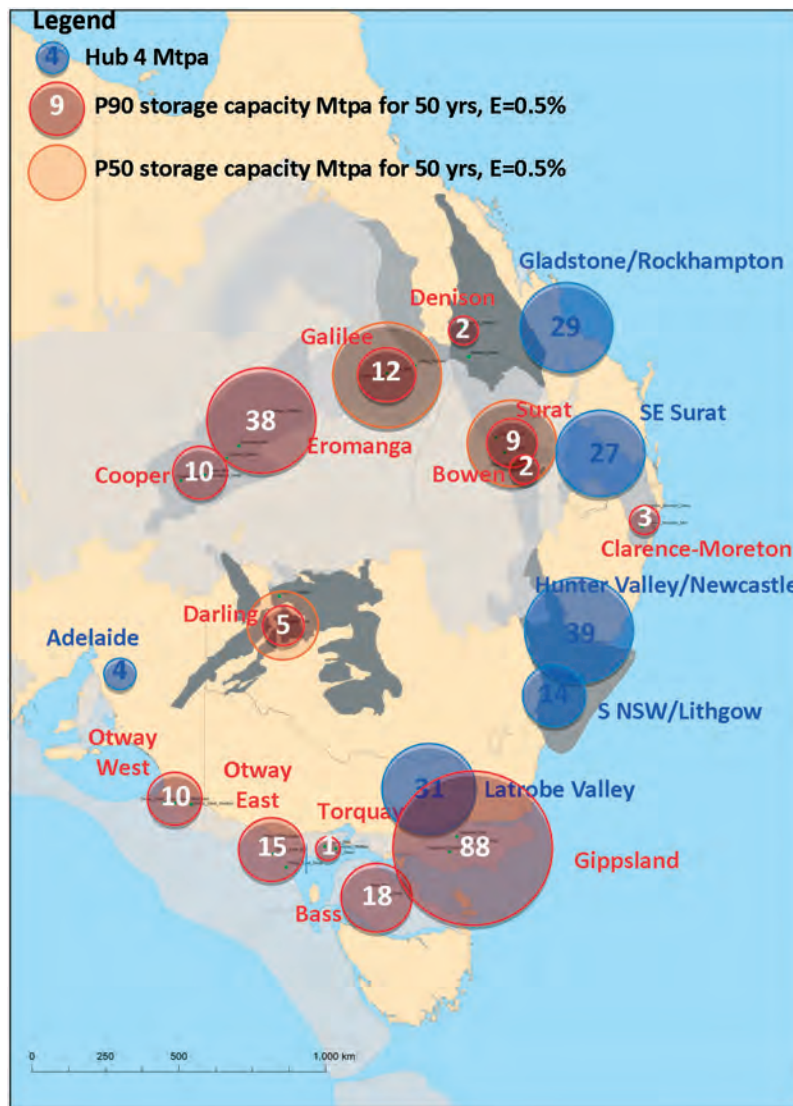
4.5 SOURCE-SINK MATCHING

Matching CO₂ sources with the hubs where the CO₂ will be collected is important in determining the economics of CCS. As discussed previously, there are concentrations of CO₂ in geographic hubs in Queensland, NSW and Victoria in eastern Australia, and in the southwest and northwest of the country in Western Australia and the Northern Territory.

Figure 24 below shows the six major eastern Australia emission hubs in blue, with the area of the blue circle indicating the magnitude of the emissions. The main eastern basins are shown as red, with the area of the circle proportional to the storage capacity of the basin in millions of tonnes of CO₂ per annum for 50 years of injection (with the conservative assumption of E=0.5%).

⁴⁶ The parameters for the shallow, mid and deep location for each basin are tabulated on the basin montages in the table entitled 'Potential Injection Parameters'.

Figure 24: Hub emission levels and basin storage capacity – eastern seaboard



As can be seen, the Gippsland Basin has the greatest capacity of the eastern basins. It is also very close to the Latrobe Valley hub (150 km). From a purely technical point of view, it is the first choice for the development of a long-term storage basin in Victoria. The Bass Basin is the alternative basin for Latrobe Valley emissions, while the Torquay Basin only has small-scale potential.

In South Australia, the Otway West Basin is the likely storage site for the Adelaide hub. The Cooper Basin could be used for the storage of reservoir CO₂ associated with the production of domestic gas from the Cooper and Eromanga basins. There is potential for the use of CO₂ in the Cooper Basin to enhance oil recovery, with oil sales offsetting some of the costs associated with geological storage.

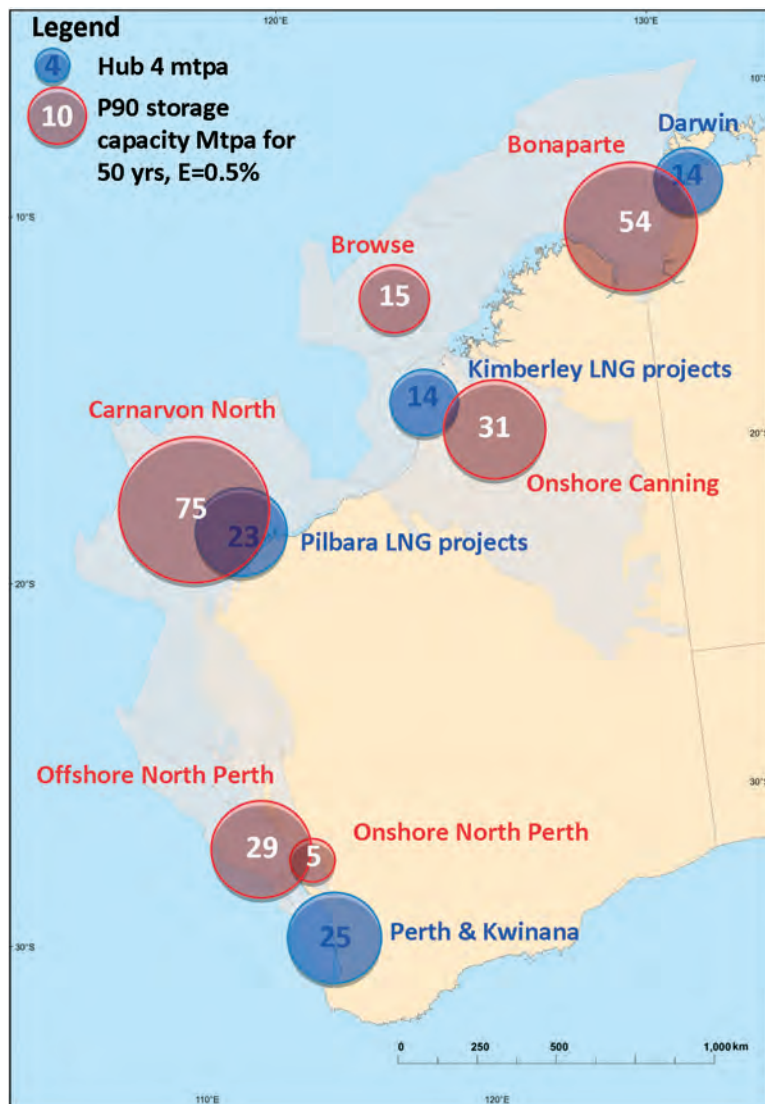
In Queensland, the Eromanga Basin has the greatest capacity, but is more than 1,200 km from the emissions hubs. Storage in this basin would incur significant transport costs. The closer Surat and Galilee basins (400 to 600 km from the emissions hubs) have storage capacity that could be used for the first 25 years as a stepping stone to Eromanga. The Denison Trough only has small-scale potential.

The New South Wales basins are relatively unexplored, but on current data the majority of the basins have low storage capacity. The one possible exception is the Darling Basin which is a large basin (by area) located in central west New South Wales. Data is very limited given the extent of this basin, but there are some indications of suitable porosity and permeability, which suggests potential for storage of CO₂. If these characteristics extend more widely, there is potential for larger scale storage, but considerable additional data will be required to confirm this potential. If the pre-exploration activities fail

to prove up potential, it is likely that major pipelines will need to be constructed to transport CO₂ from the Hunter Valley northwards to the Surat and Eromanga basins (up to 1700 km) and from the southern New South Wales hub southwards to the Gippsland Basin (1000 km). The New South Wales Government is also conducting preliminary investigations into the potential for mineral carbonation as an alternative to long distance transport to aquifer storage sites.

In the west of Australia, there are four potential hubs, as shown in Figure 25 below. These are the Perth/Kwinana industrial complex, LNG projects in the Pilbara region, LNG projects in the Kimberley region, and Darwin.

Figure 25: Hub emission levels and basin storage capacity – western seaboard



For the Perth/Kwinana hub on Australia's west coast, the most likely storage basins are the onshore and offshore North Perth Basin. In addition to aquifer storage, the onshore North Perth Basin is attractive as the initial storage location because it has a number of depleted, but small volume, gas fields as storage locations. The offshore North Perth Basin is the likely longer term storage location.

CO₂ emissions in the Pilbara region are projected to increase as new LNG and domestic gas projects come on line. The Carnarvon Basin is expected to be the storage location. Significant emissions are projected for the Kimberley region as a result of the possible development of a LNG hub to the north of Broome. The onshore Canning Basin may be the preferred storage location. The majority of emissions from the Darwin Hub are also associated with LNG production. Reservoir CO₂ could be transported to the nearby offshore Bonaparte Basin for storage.

4.6 IMPACT OF CO₂ STORAGE ON OTHER RESOURCES

CO₂ storage operations may be located in basins where other resources are, or will be, exploited. The impact of the CCS activity on other resources and operations will need to be assessed for each case.

For instance, the highest ranked storage basins are also hydrocarbon-producing basins. Other resources such as fresh water, geothermal heat, coal seam methane and coal could also be potentially impacted by CO₂ storage operations. The nature of the impact may be, for example, that production of hydrocarbons is adversely affected due to CO₂ migrating into hydrocarbon producing fields, resulting in increased corrosion and variation of product quality. Conversely, hydrocarbon production may in some instances be improved due to increased reservoir pressure resulting from CO₂ injection.

The Taskforce has identified and undertaken preliminary assessments of the two most strategically significant areas of potential resource impact: firstly, the availability of the prolific oil and gas producing Gippsland Basin for storage operations; and secondly, the risk of impact of storage operations on the freshwater aquifers of the Surat and Eromanga basins.

4.6.1 Timing of Gippsland Basin Storage Availability

The offshore Gippsland is the highest technically ranked storage basin and it has the lowest transport and storage cost per tonne of CO₂ avoided (refer Section 6). It is of strategic importance because it is the preferred storage site for Latrobe Valley emissions. It could also be the preferred storage basin for some or all of NSW's emissions, should the current pre-exploration program in NSW prove to be unsuccessful. This would require major pipeline infrastructure to be established between NSW and Victoria.

However, the Gippsland Basin is also an oil- and gas-producing basin with many currently productive fields. While some oil fields are nearing depletion, the large northern gas fields are expected to be producing well into the future.

The Taskforce has examined whether parts of Gippsland could be available for storage contemporaneously with petroleum operations. This has been assessed by estimating the timing of depletion of individual fields⁴⁷, and by examining their proximity to petroleum operations and CO₂ migration pathways. The Taskforce's estimates do not take account of any future discoveries. The evidence of how the basin filled with hydrocarbons indicates that the fields are connected along common systems. In order to maximise the depleted field and aquifer storage capacity, the location and sequence of injection sites needs to be carefully managed to prevent early projects filling structures that could preclude future storage capacity.

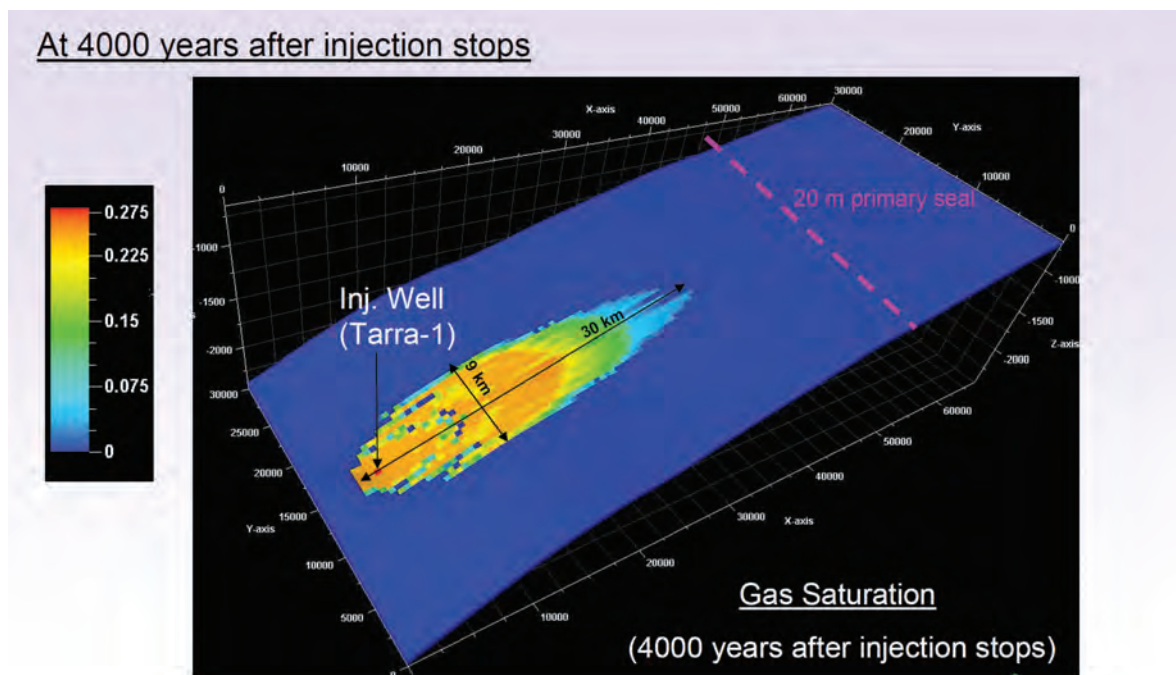
The conclusion is that storage operations could begin progressively, in a manner that is unlikely to impact on petroleum operations.

The first storage area would be located on the southern margin (contained by the areas that were released in Commonwealth offshore waters for storage exploration in March 2009). The Taskforce estimates indicate that if exploration commenced in 2010, a storage site could be ready to commence operations by around 2022. High level/preliminary reservoir simulations indicate that this area has potential CO₂ injection capacity for 50 Mtpa for 25 years.⁴⁸ Figure 26 shows the modelled maximum extension of the CO₂ plume in the Gippsland reservoir 4,000 years after injection ceases for this case.

47 RISC 2009, *Gippsland Basin – Availability Projections for Carbon Storage*, report prepared for the Carbon Storage Taskforce, Department of Resources, Energy and Tourism, Canberra

48 Department of Primary Industries 2009, *Plume Migration in Gippsland Offshore*, report prepared by Schlumberger Carbon Services, for the DPI, Melbourne

Figure 26: Size of plume extension for 50 Mt CO₂ injection



(Source: Schlumberger, provided by the Department of Primary Industries, Victoria)

The second storage area would be located under depleted southern oil fields, which could be available for storage by 2020–2025. These fields have significant in-field storage capacity, but due to the degree of interconnectedness of the basin, their use needs to be aligned with the plans for the aquifer storage to ensure that the much larger aquifer capacity is not sterilised.

The third and final northern storage area would become available after 2050, once the northern gas fields are depleted. It is also highly connected and would also require careful management of the sequence and location of injection to ensure use of storage capacity is optimised.

It is recommended that a more detailed assessment, utilising reservoir simulation techniques, be made to examine CO₂ migration pathways and aquifer pressure implications associated with injection in the southern oilfields area.

4.6.2 Great Artesian Basin

The Surat and Eromanga basins form the larger part of the Great Artesian Basin in Queensland, South Australia, New South Wales and the Northern Territory. These two basins contain vast quantities of fresh groundwater and significant hydrocarbon wealth. In the absence of newly identified storage capacity closer to sources, they have also been identified in this Taskforce study as being potential storage locations for emissions generated from the northern New South Wales and Queensland hubs.

The Taskforce commissioned a study to examine the potential impact of storage operations on freshwater aquifers⁴⁹, primarily focused on the distribution of groundwater types spatially and with depth, the mineralogy of reservoirs and seals, and the hydrochemical and geochemical reactions associated with the injection of CO₂ into the freshwater aquifers of the Surat and Eromanga basins.

⁴⁹ Geological Survey of Queensland (Queensland Carbon Geostorage Initiative) 2009, *The Potential Impact of Carbon Dioxide Injection on Freshwater Aquifers: The Surat and Eromanga Basins in Queensland*, report prepared by: J Hodgkinson, M Preda, M McKillop, O Dixon – Queensland Carbon Geostorage Initiative; A Hortle – CSIRO Petroleum, ARRC, Perth; and L Foster – Queensland Department of the Environment and Resource Management

The main conclusion of this preliminary study is that CO₂ storage can potentially operate without significantly impacting the freshwater aquifers.

Water chemistry and hydrodynamic data indicate that vertical mixing between the overlying and underlying units appears minimal and modelling indicates that the acid buffering capacity of the groundwater is large. Simulation results also suggest that the groundwater systems have the capacity to naturally remediate the induced acidified conditions resulting from CO₂ injection. Mineralogical data shows favourable mineral stability characteristics in the sandstones of the principal storage targets.

The location of carbon storage injection sites relative to existing resource and environmentally sensitive areas is critical to the mitigation of any detrimental contamination effects. The prevailing hydrodynamic regime will dictate the volume of CO₂ that can be safely stored in the long term, without negative impacts on groundwater resources, hydrocarbon production, mining operations and groundwater-dependent ecosystems.

Additional data and further interpretations are required in both basins to more clearly define potential impacts. Clearly, it would be desirable to identify storage locations that are closer to emissions sources, and that remove or reduce the potential for resource conflict. This work forms part of existing programs in New South Wales and Queensland, and the exploration program recommended subsequently in this report.

It is recommended that pre-competitive exploration of the Surat and Eromanga basins includes the collection of new data as part of a deep well drilling program and re-sampling of existing groundwater bores. Also, observation wells at the new drilling sites are recommended to provide data to establish the vertical relationships between the aquifers/reservoirs and aquitards/seals.

5 INFRASTRUCTURE REQUIRED FOR CO₂ TRANSPORT

Pipeline engineering technology is advanced, and subject to cost, many fluids can be transported using pipelines. CO₂ pipelines have been in operation internationally for over three decades.⁵⁰

CO₂ pipelines are now routinely used to transport the gas long distances in the USA for enhanced oil recovery. This is noted in an IPCC report⁵¹, where it is stated 'Carbon dioxide pipelines are not new; they now extend over more than 2500km in the western USA where they carry over 59 Mt CO₂ per year from natural sources to enhanced oil recovery projects in West Texas and elsewhere'. Details of these pipelines are given in Table 5 below.

Table 5: CO₂ pipelines in the USA

PIPELINE	LOCATION	OPERATOR	CAPACITY (MtCO ₂ /yr)	LENGTH km	YEAR FINISHED	ORIGIN OF CO ₂
Cortez	USA	Kinder Morgan	19.3	808	1984	Mt Elmo Dome
Sheep Mountain	USA	Kinder Morgan	9.5	660		Sheep Mountain
Bravo	USA	BP Amoco	7.3	350	1984	Bravo Dome
Canyon Reef Carriers	USA	Kinder Morgan	5.2	225	1972	Gasification Plant
Val Verde	USA	Petrosource	2.5	130	1998	Val Verde Gas Plants
Bati Raman	Turkey	Turkish Petroleum	1.1	90	1983	Dodan Field
Weyburn	USA & Canada	North Dakota Gasification Co.	5	328	2000	Gasification Plant
Total			49.9	2591		

The CO₂ content of the components in this pipeline network is typically greater than 95% and the transported fluids contain a range of other substances. Most of the network is situated in non-urban areas.

In Australia, there is extensive operational and regulatory experience in managing hydrocarbon (gas and oil) pipelines under the Australian Standard, AS2885. The knowledge base for hydrocarbon pipeline management has been developed both in Australia and internationally over decades, and has been able to be applied to the evaluation of risks under AS2885.

Deployment of large scale, high pressure CO₂ pipeline systems will benefit from a similar development of a knowledge base that addresses both risk and economics. From a risk perspective, industry operators and regulators will consider in detail the impact of CO₂ pipeline leakage, rupture or controlled release ('blowdown') at every section of a proposed pipeline route. Given that many CCS pipelines will be relatively long distance, it is also important that development work is focussed on cost reduction, without compromising safety. This area of work would focus on optimal design, and consider factors such as fracture control, thermodynamics, and materials selection and design, all of which are currently covered for hydrocarbon pipelines under AS2885. The knowledge developed through this process will assist design and regulatory assessment of CO₂ pipeline proposals under AS2885 and any other

50 Canyon Reef Carriers pipeline, constructed in 1972, extends 225 km from McCamey, Texas, USA to Kinder Morgan CO₂'s SACROC oil field.

51 IPCC Special Report on Carbon Capture and Storage, Ch 4, 2005

relevant codes. It will also help to identify if the risk analysis process for hydrocarbon pipelines, which is incorporated into this standard, requires any modification when it is applied to risk analysis for CO₂ pipelines.

There is an increasing body of work both in Australia and internationally providing insights into the construction and operation of CO₂ pipelines. Significant work has already been undertaken by industry operators and CCS organisations in designing CO₂ infrastructure for specific projects. It is important that Australian activities are coordinated with these international efforts. Knowledge of CO₂ behaviours and pipeline performance developed by project proponents to satisfy regulatory requirements is expensive to obtain, and so may be held as intellectual property. Release of this information into the public domain will be a decision for individual project proponents in their community engagement program. A need therefore exists to develop publicly accessible technical information from credible sources that can be used by communities and individuals to form their own judgements about CO₂ pipeline transport (refer Section 14.4 Plan Element 4: Infrastructure).

For CCS projects the necessary CO₂ transport infrastructure will involve both long distance onshore and offshore pipelines. As discussed in Section 3 above, fossil fuel power plants will produce CO₂ with varying combinations of impurities depending on the generation and capture technologies used. Although CO₂ is transported extensively in the oil industry, CO₂ pipelines have not yet been designed for the range of different gas composition conditions expected from CCS projects. Application of current design procedures to the new generation pipelines is likely to yield an over-designed pipeline facility, with excessive investment and operating costs. In particular, the presence of impurities has a significant impact on the physical properties of the transported CO₂, which affects pipeline design, compressor/pump power, re-pressurisation distance and pipeline capacity. These impurities could also have implications in the control of failure fractures in the pipeline. All these effects have direct implications on both the technical and economic feasibility of developing a carbon dioxide transport infrastructure onshore and offshore.

CO₂ properties are described in Section 3 of the report. It behaves as a supercritical fluid above its critical temperature (31.1°C) and critical pressure (72.9 atmospheres), with transport properties more like a gas but with a density like that of a liquid. As the critical temperature of CO₂ is close to standard room temperature and its critical pressure is within the range commonly used in pipeline transport, it is practical to transport CO₂ in its supercritical phase. Supercritical CO₂ has a density approximately 250 times greater than that of gaseous CO₂, so the safe transport of many millions of tonnes of supercritical CO₂ is possible and has been achieved in the USA, as mentioned.

5.1 IMPACT OF COMPOSITION OF CO₂ FOR DIFFERENT POWER GENERATION TECHNOLOGIES

Worley Parsons provided advice on the CO₂ composition requirements for pipelining in a commissioned report for the Taskforce.⁵² Table 6: below identifies the various components in the CO₂ stream from each of the three capture techniques (denoted by 'X') that can influence or become critical factors in CO₂ pipeline transport.

⁵² Worley Parsons 2009, *Carbon Dioxide Specification Study*, prepared for the Carbon Storage Taskforce, Department of Resources, Energy and Tourism, Canberra

Table 6: Impurity components in CO₂ from different coal combustion technologies showing those that influence CO₂ pipeline transport

IMPURITY COMPONENT	PRE-COMBUSTION	POST-COMBUSTION	OXY-FUEL
Water	X	X	X
SO ₂			X
H ₂ S	X		
NO			X
CO	X		
N ₂ /Ar			X
O ₂			X
H ₂	X		

The presence of impurities can pose both positive and negative effects on the operation of CO₂ pipelines and storage. Specific operational issues caused by the presence of impurities in the CO₂ stream, such as pipeline capacity, corrosion risks, equipment integrity, injection issues, etc are considered below.

Impurities can be removed from CO₂ streams for all capture technologies. The extent to which this occurs will depend on a number of factors, primarily an economic trade-off between processing and transport costs.

5.1.1 Pipeline Capacity

Pipeline capacity is a major factor for any CCS scheme. Hence, fluctuations in pipeline operating conditions due to the presence of impurities could cause variations in pipeline capacity and present both control and operational difficulties.

The presence of impurities in the CO₂ stream shifts the boundary of the two-phase region (in a phase diagram) towards higher pressures, meaning that higher operating pressures are required to keep CO₂ in the supercritical state. This, in effect, increases the compression required. The compression level depends linearly on the concentration of the gaseous impurities, with the effect of H₂ the greatest.

In order to maintain the CO₂ in the dense or supercritical phase throughout the entire pipeline, it is necessary to either maintain the inlet pressure to the pipeline at a high enough pressure to overcome the pressure loss while still above the critical pressure; or increase the pipeline diameter; or install booster stations at appropriate intervals to account for the pressure losses. Hence, the minimum pressure in the CO₂ pipeline should be set to avoid two-phase flow⁵³ which in turn depends on the type, combination and quantity of impurities present.

For a given pressure drop, the presence of impurities reduces the pipeline capacity, and this is more significant at larger pipe diameters. Since the CO₂ density is sensitive to pressure, the pressure drop along the pipeline will reduce the CO₂ density and increase the velocity, which will in turn increase the pressure drop. Transport at lower densities (i.e. in the gas phase) is inefficient because the low density of the CO₂ results in greater pressure drop per unit length and insufficient tonnage of CO₂ can be transported at the lower density.

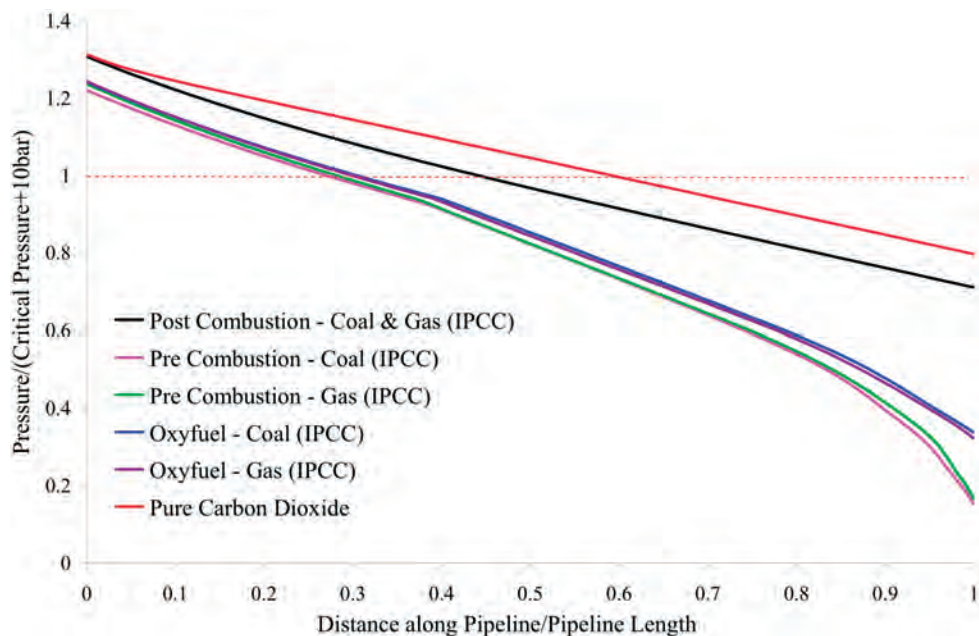
Temperature is another important operating variable as it markedly affects the transport properties of CO₂ in terms of density, compressibility and static head losses. These properties and parameters change with the presence of impurities. In terms of the three different capture techniques discussed in Section 3, oxy-fuel shows the highest reduction in transport capacity followed by pre-combustion. The post-combustion method does not show any significant deviation from transporting pure CO₂.

⁵³ Two-phase flow means concurrent flow of gaseous and liquid in a pipeline. It is undesirable for CO₂ transport in terms of pressure losses and operational stability.

Re-pressurisation along a pipeline is necessary to ensure CO₂ remains in the dense or supercritical phase. This re-pressurisation requires additional compressors at regular intervals along the pipeline. Since the supercritical CO₂ is at high pressure, the re-pressurisation energy consumption, and hence cost, is high.

Figure 27 shows, for example, modelled pressure losses along a 500km, 406mm diameter CO₂ pipeline as a function of different gas capture technologies (a proxy for different gas compositions). In the figure, the y axis is the ratio of pipeline pressure to the pressure to keep the gas in the supercritical state, so re-compression will be required when the curve falls below the value '1.0'.

Figure 27: Pressure losses in a CO₂ pipeline as a function of capture technology⁵⁴



(Used with permission of Dr J. Race, Newcastle University, U.K.)

The effect of impurities on the pressure and temperature profile of the CO₂ stream influences the location and spacing of re-pressurisation stations. H₂ has the biggest effect on re-pressurisation distance, while H₂S has the least effect. The re-pressurisation distance for the oxy-fuel method thus results in the shortest re-pressurisation distance. Re-compression distances for transport as a function of gas composition are shown in Figure 27 where it can be seen that pre-combustion and oxy-fuel technologies introduce much shorter pipeline re-compression distances, and hence higher costs, than pure CO₂ and post-combustion technology. It is important to note that Figure 27 represents pressure loss in the specific pipeline detailed in the footnote. Each unique pipeline will have its own pressure loss characteristics. However, pressure loss as a result of impurities will occur in all pipelines.

The storage capacity in the basin is also affected by the CO₂ impurities. A decrease in density caused by impurities in the CO₂ stream can reduce the storage capacity at the injection site, resulting in additional storage costs and/or reaching the maximum storage capacity faster than by pure CO₂ injection.

5.1.2 Pipeline Corrosion

The main factor that dictates corrosion in CO₂ pipelines is the presence of free water in the CO₂ stream, either carried over from the upstream process facilities or liberated within the pipeline due to pressure losses leading to precipitation of water. The corrosion rate of carbon steel in dry supercritical CO₂ is low, and field experience indicates very few problems with transport of high-pressure dry CO₂ in carbon steel

⁵⁴ Modelling was conducted for a 406.4 mm outside diameter pipeline, wall thickness 6.35mm and total length of 500 km with no elevation change. The pressure inlet was 110 bar, the outlet temperature was 50 °C and the ambient temperature was 5 °C. The average steady state flow rate was 72 kg/s.

pipelines. It has also been found that dry CO₂ does not corrode carbon steel pipelines as long as the relative humidity is less than 60% in the presence of the N₂, NO_x and SO_x contaminants.

For CO₂, the proportion by mass of dissolved water increases with pressure and decreases with temperature. In particular, there is a shift towards higher solubility of water in CO₂ when the pressure passes the transformation from the gas phase into the dense liquid phase.

Consequently, drying CO₂ at a higher pressure and lower temperature than the operating envelope retains a large amount of dissolved water, which will drop out as free water during operation due to temperature or pressure changes.

The corrosion rate also decreases with increasing CO₂ pressure or decreasing temperature. Further, an increase in pH level has generally led to a reduction of the corrosion rate in CO₂ systems. Limited work has shown that the addition of a film-forming corrosion inhibitor may be effective. Also, if the CO₂ stream contains H₂S, iron sulphide is formed as by-product from H₂S corrosion. This has a positive effect, as it forms a protective thin film on the inside surface of the pipeline.

5.2 EFFECTS OF CO₂ IMPURITIES ON ECONOMICS

The overall economics of CCS are significantly affected by the economics of capture and transport. As pointed out above, CO₂ capture will likely result in the co-capture of other chemical compounds in the process gas from the range of industrial facilities. Reducing the concentration of trace elements and obtaining a high purity CCS stream is often technically feasible, but purification steps most likely lead to additional costs and increased energy requirements. On the other hand, if the CO₂ stream is not scrubbed to remove impurities, costs may increase downstream in terms of transport cost, injection costs, maintenance and monitoring. Minimisation of capture, transport, and injection costs will therefore become an optimisation problem based on the CO₂ gas composition.

5.3 SAFETY OF CO₂ TRANSPORT

The health and safety associated with the transport of CO₂ must be taken into consideration in case of unplanned leaks or operational venting. This is important for a CCS system as the CO₂ stream, although non-toxic at normal atmospheric concentrations, can pose health and environmental risks at other concentration levels.

The main safety issue for pipeline transport of large volumes of CO₂ is the risk of sudden, unplanned leakage. CO₂ is denser than air and can therefore accumulate to potentially dangerous concentrations in low-lying areas if a pipeline rupture occurs. Without odourisation, these accumulations could be difficult to detect. Significant cooling, and the formation of solid CO₂ (or 'dry ice'), would also accompany any rapid emission of CO₂. Therefore, an appropriate risk and safety assessment will need to be conducted to quantify and mitigate such risks when a pipeline is being designed and built.

Besides the safety issues of the CO₂ itself, other compounds such as H₂S or CO may also pose safety and toxicity risks. This is because they are toxic at low concentration levels. There are existing and established occupational exposure limits that regulate airborne exposure to toxic compounds in working environments. The National Occupational Health and Safety Commission⁵⁵ provides information on the exposure limits of these gases. Facility operators will need to be aware of the health and safety risks associated with leakage of both CO₂ and the possible toxic trace gases and will need plans for mitigation of those risks and for emergency response in the event of leakage.

Another aspect of safety for CO₂ pipelines is the possibility of pipeline fracture during service. In-service ductile fractures of natural gas pipelines have occurred for up to 300m of pipeline length.⁵⁶ Additionally, in the case of CO₂, there is risk of a long running brittle fracture mechanism due to severe cooling around any leaks. This is because the temperatures of the gas during decompression can fall to lower

⁵⁵ <http://safeworkaustralia.gov.au/>

⁵⁶ Race, J. Presentation to APIA, Melbourne, 4 June 2009. School of Marine Science and Technology, University of Newcastle UK.

than minus 50°C and steel can be brittle at these temperatures. There will thus be a need to develop an understanding of the nature of the CO₂ decompression process and the pipeline fracture mechanics and velocity for supercritical CO₂ pipelines. This knowledge will also need to encompass the influence of impurity gases on the decompression process. Further, the low temperatures during decompression may lead to the formation of solid CO₂ particles, which may in turn cause escalation of the fracture by high velocity impingement of the particles on other parts of the infrastructure. Australian Standards for transport of high-pressure gas consider both ductile and brittle fracture mechanisms. However, appropriate further national standards for pipeline design and construction may need to be developed to deal with the issues of CO₂ transport relative to natural gas.

Figure 28: Pipeline fracture arrestor



(Used with permission of Clock Spring Company LP)

Brittle fractures can be prevented, and ductile fractures controlled, by the toughness of steel used to construct the pipeline. In addition, propagating fractures can be arrested using mechanical collar devices that surround the pipe (called 'crack or fracture arrestors') along the pipeline, as shown in Figure 28. For example, CO₂ and other high pressure pipelines in the USA have deployed crack arrestors at 3.2 km intervals in remote areas, and at 400m or 100m intervals close to infrastructure such as road crossings.

5.4 CO₂ STREAM SPECIFICATIONS

For long distance transport the gas should be as pure as practicable to ensure pipeline and re-compression costs are as low as possible. This implies that optimisation between the costs of capture (a function of sent gas purity) and the costs of transport (a function of received gas impurity) will need to be carried out for each hub combination. Alternatively, higher transport costs will need to be borne for those operators that send more impure gas to the pipeline hub.

Some pipeline networks specify the composition of the streams to be carried. A common Australian specification for the streams to be transported in CO₂ pipelines in Australia is not needed because each power generation facility could have a different CO₂ gas composition, depending on the technology deployed and the mode of capture. Individual transport systems or networks should set their own specifications for hubs based on the source emissions profile and requirements at the storage sites. Taskforce investigations suggest that for long distance transport systems, the economic driver to reduce pipeline material and recompression costs is likely to result in specifications that seek high concentrations of CO₂ with minimal impurities.

5.5 USE OF EXISTING PIPELINE INFRASTRUCTURE

Australia's extensive high pressure gas transmission pipeline infrastructure is privately owned and currently in use conveying hydrocarbons. The Taskforce has assessed these pipelines as unsuitable for the transport of CO₂, as the cost associated with converting these pipelines for CO₂ transport would be similar to the construction costs of a new pipeline. The one possible exception is the 1,375 km Moomba – Botany (Sydney) pipeline, completed in 1996, which transports ethane at similar pressure ranges to those required for transport of CO₂ in the supercritical phase. Technically, this pipeline could be used for CO₂ transport, but at rates less than those anticipated for large scale deployment.

There are two main factors affecting a pipeline's suitability to transport CO₂: compression facilities and the pipeline construction material.

5.5.1 Compression Facilities

All gas transmission pipelines are fitted with compression stations that provide the necessary pressurisation to ensure the required volumes of gas can be transported. As it is proposed to transport CO₂ as a supercritical fluid, which has density like a liquid, it is necessary to use pumps rather than compressors in order to provide appropriate pressure for the pipeline. Whilst the physical principles that apply to a pressurised pipeline using either pumps or compressors are the same, the equipment used is different. It is the assessment of the Taskforce working group that it is impractical, if not impossible, to modify compressors to be used as pumps, which means that any existing pipeline would require new pumping equipment before it could consider transporting supercritical CO₂. Whilst every case is unique, it is expected that a pumping station capable of pressurising a pipeline sufficiently to transport 10 Mtpa of CO₂ several hundred kilometres would require an investment in the vicinity of \$60–100 million just for the compression station.

This recompression will typically require a substantial power source. For larger pipelines, the demand will need a supply independent from the electrical grid. This requirement adds a cost constraint to route design, as either a gas supply or an electricity transmission line will be required to power the compressor stations.

5.5.2 Pipeline Material

To transport supercritical CO₂, it is necessary to ensure that the pipeline remains at a sufficient pressure to keep the fluid in the supercritical phase. For CO₂, this means a pipeline must exceed 7.38 MPa in pressure. Existing pipelines capable of operating at or above this pressure are limited to pipelines made from Class 900 Steel, which are capable of operating up to 10 MPa.

These Class 900 pipelines are not immediately suitable for transport of supercritical CO₂. For example, new fracture control systems would need to be installed. This would effectively require that the entire pipeline be excavated (most likely in 200 to 300 metre sections) so that fracture control collars could be placed at appropriate intervals. The costs associated with this excavation and retro-fitting process would be similar to the construction costs of a new pipeline, minus the purchase cost of the pipeline steel.

It is therefore impractical on cost considerations to consider the transport of supercritical CO₂ in any existing natural gas transmission pipelines.

5.5.3 Transporting Gaseous CO₂

Many existing pipelines would be capable of transporting gaseous CO₂. The technical aspects of this have not been considered, as the volumes of CO₂ capable of being transported in the gaseous form are significantly lower than the volume that can be transported when CO₂ is in the supercritical phase. Under these conditions the pipeline capacity would be reduced by 250 fold when transporting gaseous CO₂.

5.6 PIPELINE CONSTRUCTION AND LEAD TIMES

Pipeline construction will be a key element of CCS project timelines. There are multiple factors affecting pipeline project timeframes and each project is unique. In general, without incurring exceptional costs, the timeframe for a 300–450 mm (12–18") pipeline between 300 and 700 km in length is 24–36 months after Final Investment Decision (FID) is reached. Prior to reaching FID, an extra 12–24 months of feasibility and environmental assessments and front end engineering design (FEED) will need to have been undertaken. In the case of the first CO₂ pipelines to be built in Australia, it is expected that the process to reach FID including environmental assessment, land access and native title issues, will be more protracted, and could extend up to 36 months in duration. This suggests that development could take between three and six years.

Once the construction phase has commenced, a typical pipeline project can achieve construction rates of up to 4km per day using automatic welding technologies. It is also possible to accelerate this phase through the allocation of extra resources.

Larger diameter pipelines⁵⁷ will result in slower construction speeds, but not in proportion to their size. However, it is important to note that since 1984 no major onshore pipeline of larger diameter than 660 mm (26") has been built in Australia. The pipeline construction industry will therefore have to gear up to be able to handle pipe of up to 1200 mm (48") diameter and commensurate wall thicknesses to 22+ mm. Equipment for such pipelines can be imported, but there may be shortages if the world is building CO₂ pipelines for CCS.

There are projects under consideration, centred around the proposed LNG facilities at Gladstone, Queensland, that will potentially result in pipelines between 813 mm and 914 mm (32" and 36") diameter being constructed in the short to medium term, and this would mean the necessary equipment could be in place in Australia. There is clearly value in timing CO₂ pipeline projects to take advantage of this.

While Australia has the technology to make X-80 steel plate⁵⁸ for large Submerged Arc Welded (SAW) pipe, we do not currently have the capability to make the pipe, since the last SAW mill closed in about 1984. Hence we will be faced with importing pipe or building a new SAW pipe-manufacturing facility. It would be relatively easy to set up appropriately sized pipe coating plants.

5.7 PIPELINE REGULATION AND STANDARDS

In the USA, CO₂ is covered by the existing liquids pipeline code (ASME B31.4), since it considers CO₂ compressed above its critical pressure as a liquid.

In Australia, Australian Standard (AS) 2885 is the most appropriate standard to apply to CO₂ pipelines. However it has not yet been extended to cover CO₂ pipelines. AS2885 applies to steel pipelines and associated piping and components, 'that are used to transmit single-phase and multi-phase hydrocarbon fluids, such as natural and manufactured gas, liquefied petroleum gas, natural gasoline, crude oil, natural gas liquids and liquid petroleum products'. Although this definition does not include CO₂, AS2885 includes a clause for inclusion under special circumstances for pipelines transporting other fluids. This clause has been implemented for other substances (for example non-hydrocarbon gases and slurries). Further research is underway to provide the basis for future amendments to fully cover CO₂ pipelines under AS2885.

⁵⁷ It is expected that pipelines for CCS are more likely to be in the 600–900 mm (24–36") range.

⁵⁸ X-80 steel plate properties: <http://www.kaker.com/std/ctt/html/3662.html>

The transport of CO₂ in pipelines is covered by both the states and the Commonwealth for their respective jurisdictions.

- In areas of Commonwealth jurisdiction, transport of CO₂ is provided for under the *Offshore Petroleum and Greenhouse Gas Storage Act 2006*.
- In South Australia, CO₂ has been defined as a regulated substance to allow it to be transported under the *Petroleum Act 2000*.
- In Queensland, CO₂ transport is allowed under the *Petroleum and Gas (Production and Safety) Act 2004*.
- In Victoria, CO₂ transport is regulated by the *Victorian Pipelines Act 2005*.
- In New South Wales, pipeline transport is regulated under the *Petroleum (Onshore) Act 1991* and *Petroleum (Offshore) Act 1982*.
- In Western Australia, the Gorgon Project CO₂ transport and disposal is facilitated by the *Barrow Island Act 2003*.

6 ECONOMIC COMPARISONS OF HUB-BASIN COMBINATIONS

Transport and storage tariffs⁵⁹ have been calculated for large-scale source-sink combinations.^{60, 61} For this calculation, the Taskforce commissioned several studies from experts to investigate the costs of pipelines and the infrastructure requirements from the emission hubs to the storage locations. The estimates are subject to large uncertainties, are only indicative and could change substantially over time as technologies, storage capacities, equipment costs and other variables change. They are based on rule-of-thumb techniques for estimating equipment sizes and the costs of individual items of equipment and associated services, and on assessment of subsurface potential at a screening level only. More detailed and extensive feasibility studies, based on more data, need to be undertaken as part of initial scoping work by project proponents before investment in any CO₂ storage projects could be considered.

The main factors affecting the economics of carbon storage are the location (the distance from the CO₂ source to the storage location determines pipeline costs), reservoir depth (influencing well costs), and injectivity parameters (notably permeability and differential pressure, which determine the number of wells needed).

6.1 TASKFORCE STUDIES

The first study, by Worley Parsons, reported on the costs of CO₂ pipelines as a function of their size.⁶² The costs ranged from \$358,000 per km for a 200mm internal diameter, to \$2,940,000 per km for a 1050mm internal diameter pipeline. This study also proposed hypothetical but realistic pipeline networks for each of the three Queensland, NSW and Victorian hubs.

The study also included an analysis of the Latrobe Valley hub network storing CO₂ in the Gippsland Basin. A number of scenarios for pipeline construction were considered in terms of combinations of existing and possible emitter locations. The total capital costs for a pipeline to an onshore Gippsland Basin injection location varied between \$160 million to \$300 million, depending on which emission sources were included initially. This equates to a capital cost range of \$4.3–\$5.5 million per Mt per year of CO₂ transported for the Gippsland hub.

The study showed that careful analysis needs to be undertaken to determine the optimal manner to stage pipeline development to choose the lowest cost development pathway, even in one location. For example, a decision will need to be made in the Gippsland hub whether to size the initial pipeline for a few emission sources that have already established a business case to install capture equipment, with subsequent investment in pipeline looping to accommodate future emitters. This would lead to a smaller initial investment. Alternatively, a decision to size the pipeline to accommodate all emitters from the start could be made at higher cost, with the attendant downside risk that some of these may never join the pipeline.

The Worley Parsons study also qualitatively considered two other hubs: the Hunter Valley hub in NSW and the Gladstone/Rockhampton hub in Queensland. It noted that these hubs have sinks that are considerably further from the sources than the Latrobe Valley hub. Although the costs for the longer

59 Cost per tonne of CO₂ avoided, calculated using the net present value of cash flows and avoided emissions over a 25 year asset life.

60 Allinson, WG Cinar, Y Hou, W & Neal, PR 2009. *The Costs of CO₂ Storage in Australia*, School of Petroleum Engineering, The University of New South Wales, Sydney, Australia. CO2TECH Report Number RPT09-1536, prepared for the Carbon Storage Taskforce, Department of Resources, Energy and Tourism, Canberra.

61 Allinson, WG Ho, MT Neal, PR Wiley, DE, 'The methodology used for estimating the costs of CCS', in *Proceedings of the 8th International Conference on Greenhouse Gas Control Technology (GHGT-8)*, Trondheim, Norway, 19–22 June 2006, Paper #0191

62 Worley Parsons 2009, *Collection Hub Study*, prepared for the Carbon Storage Taskforce, Department of Resources, Energy and Tourism, Canberra

pipelines will be considerably higher in these cases, the savings for pre-investing in large pipeline capacity will be greater. With longer pipelines, there is the ability to add pumping stations at regular intervals to increase capacity. This is generally a less expensive means to increase capacity than pipeline looping.

M.J. Kimber and Associates noted in its report to the Taskforce that compressors with drive motors having an output power of 40 to 50MW will be required at the capture plants and that compressors/pumps will be required at about every 200–300km along the pipelines for re-compression.⁶³ In another study, Worley Parsons determined that a 10MW pumping duty unit would have a capital cost of \$40–45 million.⁶⁴

Resource Investment Strategy Consultants (RISC) undertook a study for the Taskforce on CO₂ injection well cost estimation⁶⁵. For this study, the Taskforce provided characteristics for each geological basin in terms of water depths (for offshore basins) and injection depths for the three cases: shallow, mid and deep. From this, RISC used its proprietary cost estimating tool to assess the costs of CO₂ injection wells for the different depths in the different basins. Previous Australian well drilling time versus depth data was used for benchmarking and cost index data for drilling and steel costs were also used in the estimations. Costs for different basins ranged from approximately \$4 million to \$10 million per well for onshore basins, and \$13 million to \$34 million per well for offshore basins, depending on depth.

CO2Tech, the commercial arm of the CO2CRC, was commissioned by the Taskforce to integrate the above cost information into a 'best estimate' of costs of CO₂ transport and storage for defined locations on the east coast of Australia. This work took a number of cases where the CO₂ from each hub was transported to a suitable basin and stored. Data from the hub emissions was used to provide the volume data for each pipeline. Basin data from the previous porosity and permeability analysis was used to determine the number of wells required for the given CO₂ flows. Transport and storage cost data were as for the studies mentioned above.

Individual as well as combined cases were considered. For example, the Latrobe Valley to Gippsland was considered as an individual case (~18 Mt per year), and a combination of southern NSW plus Latrobe Valley to Gippsland was also considered (~31 Mt per year). Similarly, south Queensland to the Surat basin (~18 Mt per year) as well as the Hunter Valley plus south Queensland to Surat were considered (~52 Mt per year).

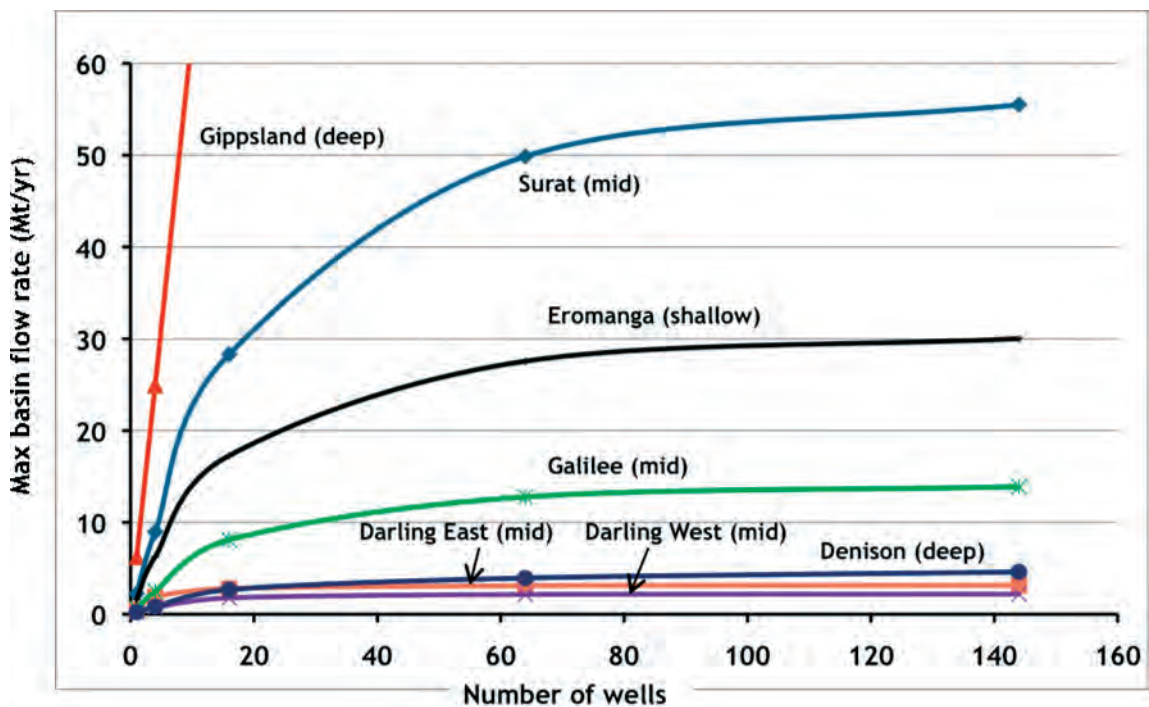
Basic reservoir simulation was carried out for each of the cases by CO2Tech. This produced graphs such as Figure 29, which shows the maximum basin injection rate as a function of the number of wells required. The quality of the Gippsland basin for CO₂ storage is clear in this figure, since a large volume of CO₂ can be stored quickly with few wells in this case. However, there are other factors which also have to be considered in the selection of storage sites, such as the potential to impact on other resources. Conversely, the large number of wells required for low CO₂ flows (with accompanying high costs) can be seen in some of the other basins.

63 M.J. Kimber Consultants 2009, *Development of Australia's natural gas resources: a possible model for carbon capture, transportation and storage*, report prepared for the Carbon Storage Taskforce, Department of Resources, Energy and Tourism, Canberra

64 Worley Parsons 2009, *CO₂ injection and pumping study*, prepared for the Carbon Storage Taskforce, Department of Resources, Energy and Tourism, Canberra

65 RISC 2009, *CO₂ injection well cost estimation*, report prepared for the Carbon Storage Taskforce, Department of Resources, Energy and Tourism, Canberra

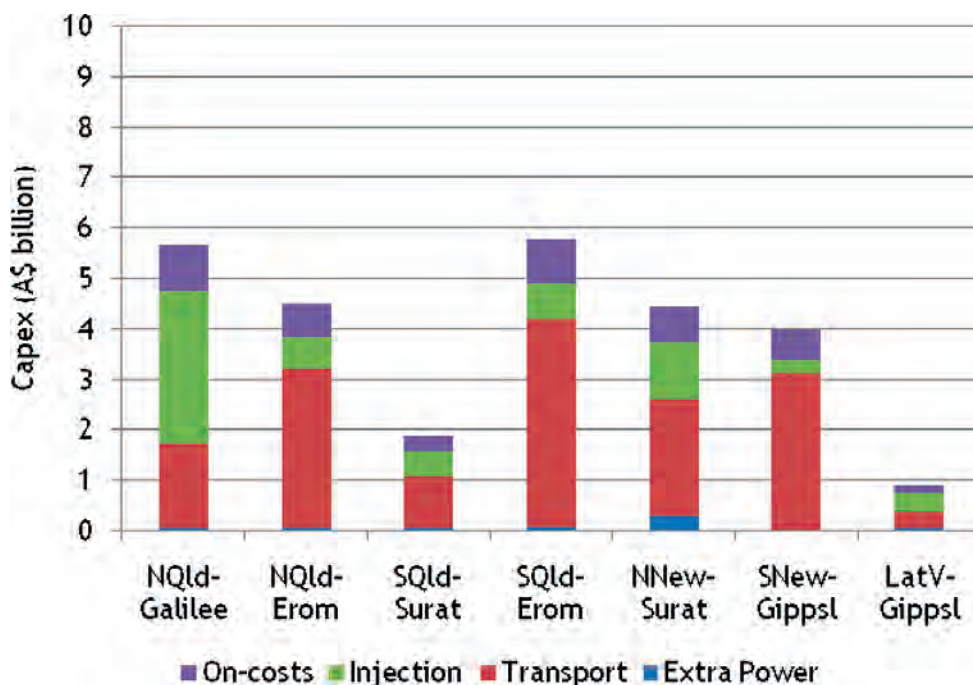
Figure 29: Reservoir simulation results for various basins



Costs were calculated for the range of cases considered by modifying the maximum rates of injection using the practical injection rates achieved in operating CCS facilities in the oil industry.

Figure 30 shows capital cost estimates for individual basins based on this approach.

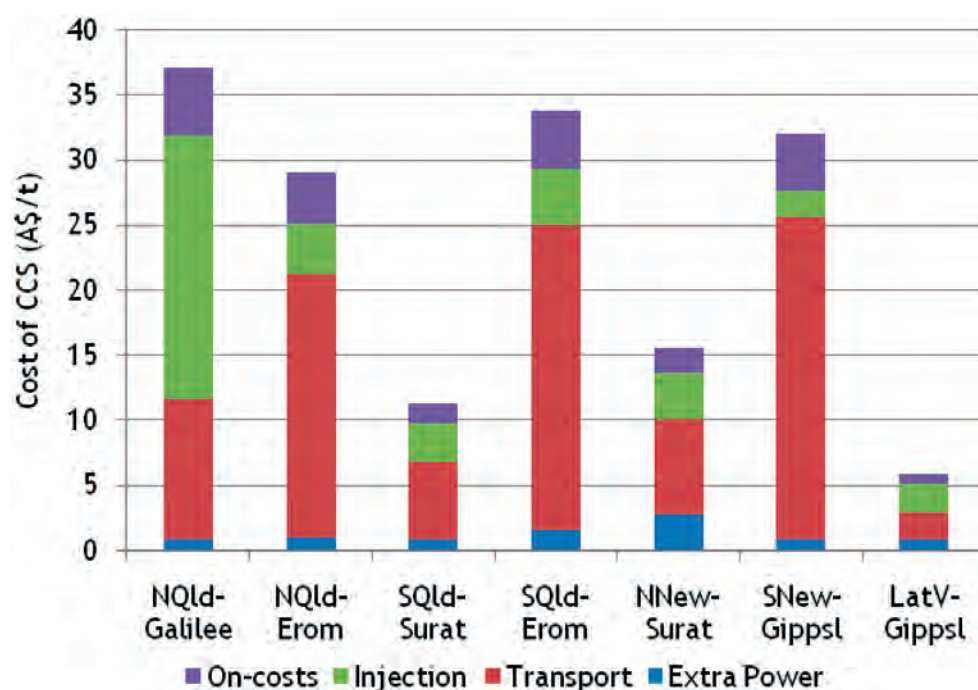
Figure 30: Capital cost estimates for individual basins and hubs for the best-case injection scenario



The relative advantage of the Gippsland and Surat basins is clear from the figure.

Figure 31 shows the estimated costs in terms of 'dollars per tonne of CO₂ avoided' for the transport and storage components of CCS for individual basins. As can be seen, the Gippsland and Surat basins again have the lowest cost, and the calculated transport and storage tariffs vary considerably from basin to basin.

Figure 31: Cost in terms of 'per tonne of CO₂ avoided' for individual basins and hubs for best-case injection scenarios



The CO2Tech study also considered the variation in costs due to the range of basin injection conditions (e.g. depth of injection – shallow, mid or deep). For these cases there was relatively large variation in both capital and avoided CO₂ costs – in some cases the variation was above \$50 and \$100/t CO₂ avoided.

Figure 32 shows a summary of the break-even transport and storage tariffs for a variety of hub-basin combinations from the above studies. As can be seen, the Gippsland Basin in Bass Strait is Australia's most suitable storage basin, and it has the greatest storage capacity of the east coast basins. Because of its proximity to the Latrobe Valley and its excellent reservoir properties, its break-even tariff for CO₂ avoided is \$7–10/t CO₂ or about \$7–10/MWh.⁶⁶

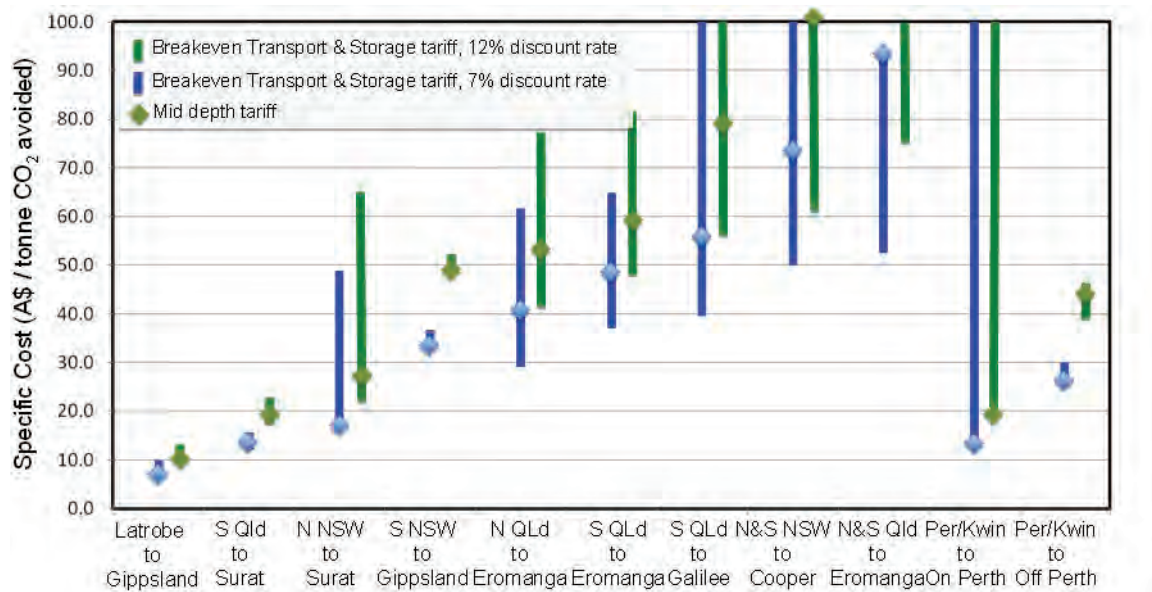
In contrast for example, the Gladstone/Rockhampton hub with storage in the Eromanga Basin has a break-even tariff for CO₂ avoided of \$29–62/t CO₂ or about \$25–83/MWh.⁶⁶

Neither the cost of capture nor the capital charges associated with the new power generation technologies are included in these tariff estimates. They refer to transport and storage only.⁶⁷

⁶⁶ Calculated using 962kg CO₂/MWhr for the Gippsland Basin and 906kg CO₂/MWhr for the Eromanga Basin; 95% capture rate; shallow, mid and deep transport and storage tariffs.

⁶⁷ Estimates of the projected cost of power generation technologies, including CO₂ capture, from the range of technologies currently proposed vary widely, and are subject to large assumptions on learning curves and capital costs for different technologies over the next decades. It is also important to note that the tariff figures provided should not be combined with capture unit costs by simple addition. The emissions not avoided need to be also taken into account, as well as assumptions on compression costs.

Figure 32: Break-even transport and storage tariffs for hub-basin combinations



The calculations which resulted in the tariffs shown in Figure 32 did not include historical exploration costs. However, these were considered in sensitivity analyses. These analyses were undertaken for the Surat Basin and included assessment of the impact of monitoring, drilling extra wells, well workovers, the cost of exploration, appraisal and development planning and the discount rate on the calculated tariffs. Of these factors, the discount rate has by far the biggest impact. Changing the real discount rate from 7% to 12% increases the cost of CO₂ avoided by about 40% (Figure 32). Oil and gas companies use higher discount rates as a means of accommodating exploration and sovereign risk. The other sensitivities typically add less than 10% to tariffs.

It is also important to note that the analysis considered only large-scale deployment and utilisation, which yields substantial economies of scale. In practice this will not apply to 'early mover' projects. Installing infrastructure with a capacity to meet future demand is unlikely unless governments play a central role in large-scale infrastructure development and mitigation of the initial utilisation risk.

7 IMPACT OF TRANSPORT AND STORAGE TARIFFS ON ENERGY FUTURES AND FUTURE EMISSIONS

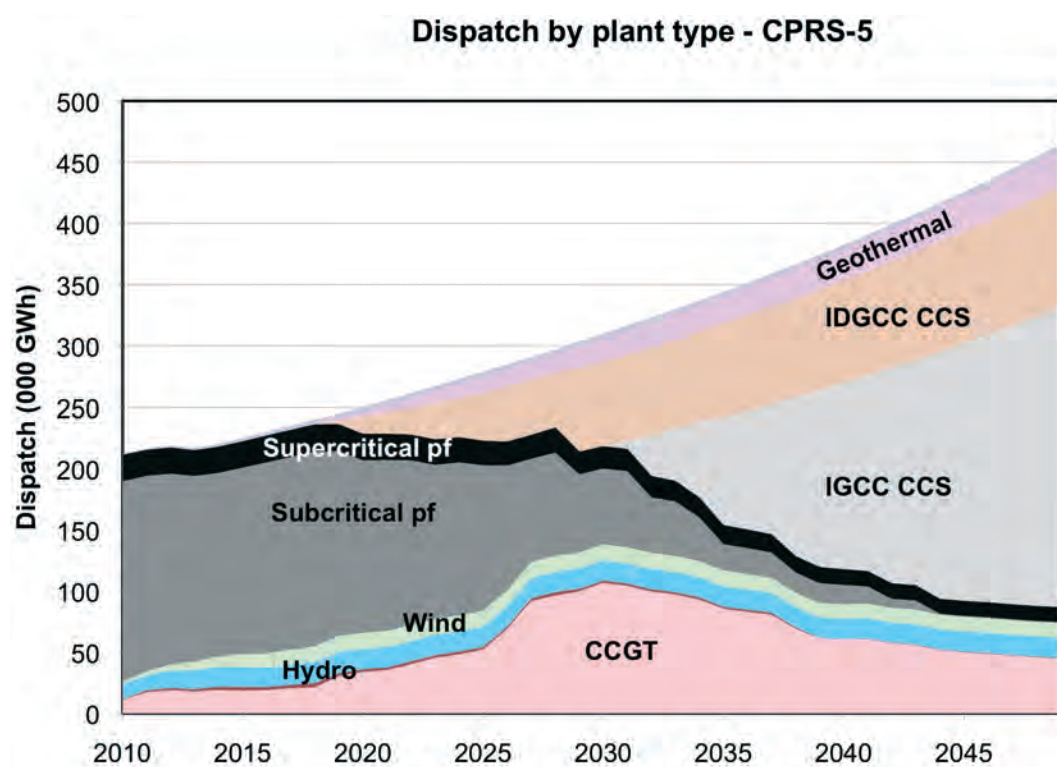
For the CPRS-5 regime projected out to 2050, almost 250 Mtpa of CO₂ will be captured and stored from power generation operations.

The first capture hub is likely to be located in the Latrobe Valley in 2020-2025, due to its significant competitive advantage, arising from relatively low carbon transport and storage costs.

The impact of variable carbon transport and storage costs on the National Energy Market (NEM) has been modelled for the Taskforce.⁶⁸ The analysis, therefore, only applies to New South Wales, Victoria, Queensland and South Australia, and excludes Western Australia which is not part of the NEM.

Under the CPRS-5 regime projected out to 2050 where carbon prices rise to \$127/t CO₂ equivalent⁶⁹, the modelling suggests that generation from existing plant is expected to peak in 2020 and then progressively decline as new power generation plants enter the market. New entrants are projected to provide 73% of generation in 2050, as shown in Figure 33 which shows the projected electricity dispatch by plant type in the NEM as a function of time.

Figure 33: Impact of variable carbon transport and storage costs on the National Energy Market (NEM)

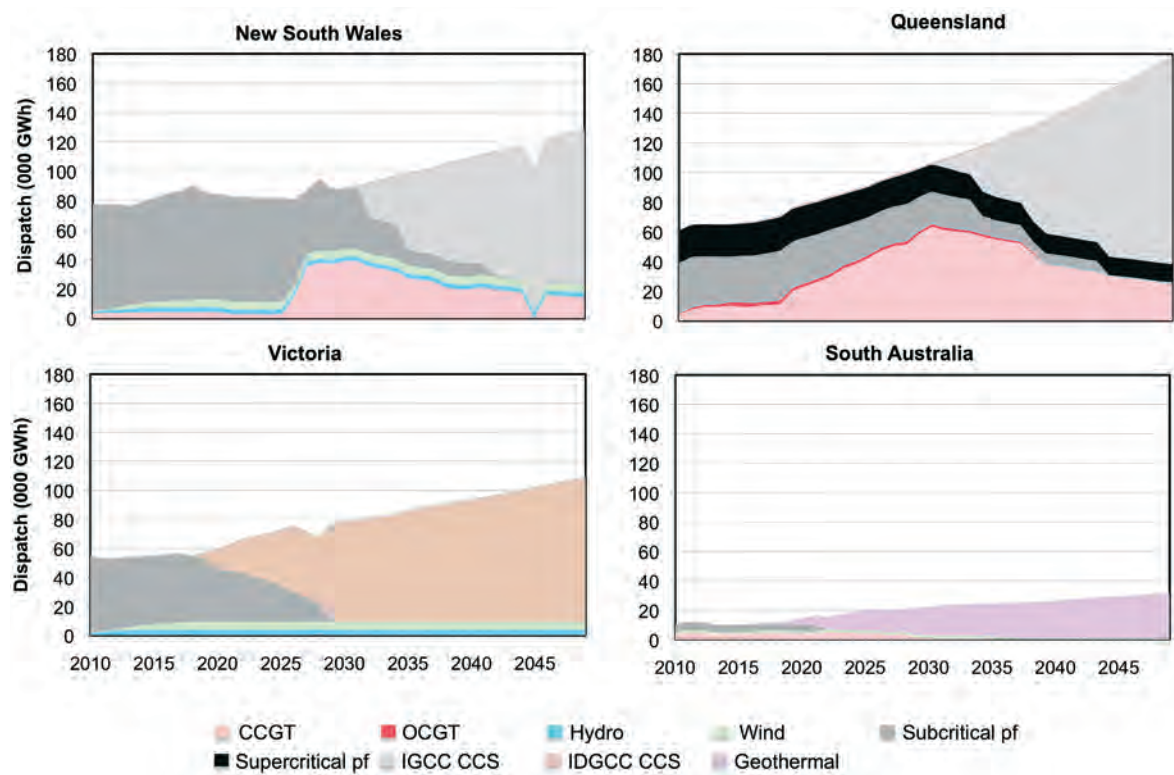


⁶⁸ ACIL Tasman 2009, *Carbon Capture and Storage Projections to 2050*, report prepared for the Carbon Storage Taskforce, Department of Resources, Energy and Tourism, Canberra. The analysis used power generation and capture costs provided in: ACIL Tasman, *Fuel resource, new entry and generation costs in the NEM*, Final report, April 2009.

⁶⁹ Department of the Treasury 2008, *Australia's Low Pollution Future – The Economics of Climate Change Mitigation*, Department of the Treasury, Canberra. CPRS-5 regime: Application of the Carbon Pollution Reduction Scheme (CPRS) using an emissions reduction target of 5% by 2020.

Initially, new entrants are likely to locate in the Latrobe Valley, due to the lower cost of carbon transport and storage in the Gippsland Basin. The first commercial capture and storage from power generation is modelled to occur in 2020 in the Latrobe Valley, with a slower uptake of this technology in NSW and Queensland due to higher carbon transport and storage costs. Figure 34 shows further details on the projected power generation in the NEM by plant type and state for this scenario.

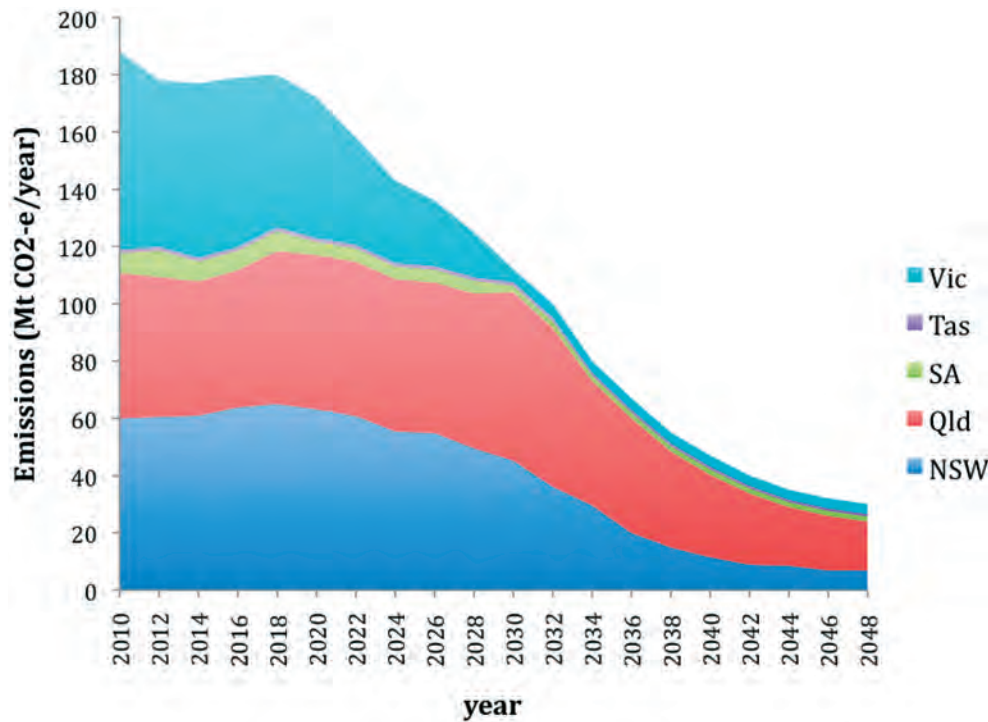
Figure 34: Power generation by plant type and state under CPRS-5 scenario projected to 2050



As shown in Figure 34, new generators also come on line around 2020 in Queensland and New South Wales, but growth in new generation in these states with CCS is initially slow due the higher carbon transport and storage costs. After 2030, CCS is projected to be commercially attractive to New South Wales and Queensland generators as carbon and electricity prices increase.

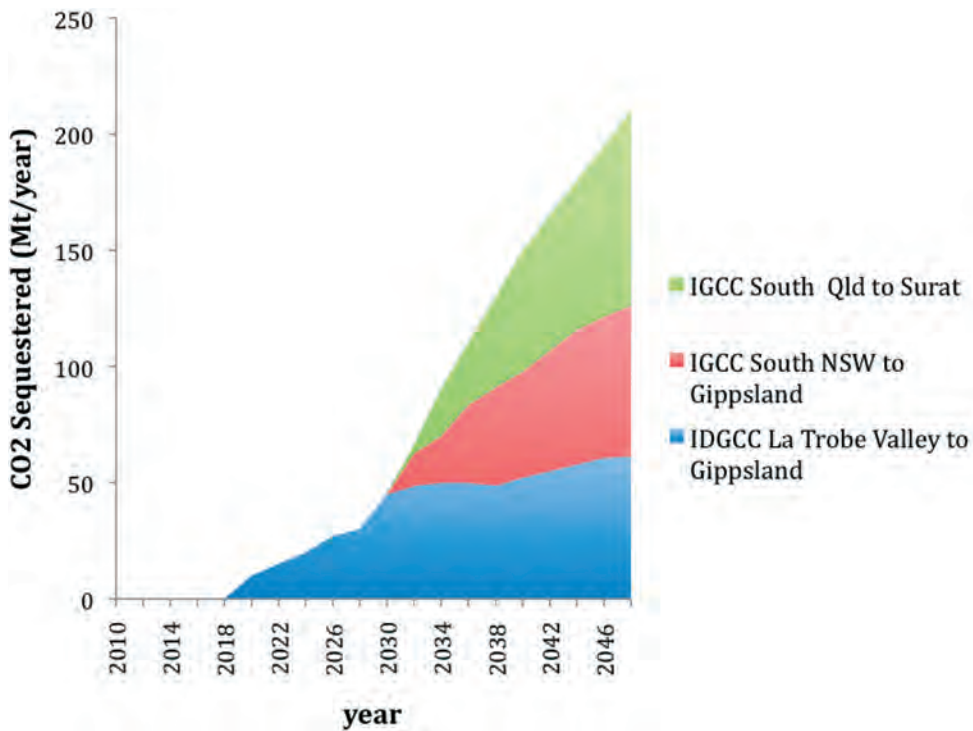
Under the CPRS-5 taken to 2050, significant emission reductions are projected to occur in the NEM, as shown in Figure 35.

Figure 35: Projected NEM emissions by state under CPRS-5 projected to 2050



By 2030, some 50 Mtpa of CO₂ from the Latrobe Valley could be avoided using CCS technology with storage in the Gippsland Basin. The scenario modelled suggests that almost 250 Mtpa of CO₂ could be captured and stored from power generation operations by 2050, as shown in Figure 36.

Figure 36: Projected CO₂ capture and storage from NEM power generators by state under CPRS-5 projected to 2050



Under the CPRS-5 scenario, CCS facilities developed in NSW export CO₂ to Gippsland, while Queensland CCS plants store locally in the Surat Basin. Transport and storage costs are expected to be key considerations, and these may outweigh fuel cost differentials in some cases. This may lead to power generators being sited as close as possible to the CO₂ storage locations, rather than the fuel source. There are infrastructure implications in this for Australia, since there will need to be optimisation between pipeline (CO₂) and rail transport facilities (fuel) in some states. Clearly, the ideal generation site would have access to both a suitable coal resource and CO₂ storage.

Further analysis of interconnector capacity between regions is required because additional interconnection may occur if the cost of connection capacity is less than the CCS price differentials between regions. This may lead (for example) to additional development of low cost CCS plant in Victoria, or further development of geothermal resources in South Australia.

This modelling assumes that alternative energies such as geothermal and solar thermal are not successful in competing economically at the scale required to meet projected energy demand, at least in states other than South Australia where geothermal energy is projected to develop after 2020. If these, or another form of energy, were able to compete at carbon prices of around \$57/tonne CO₂-e, then the new power generation plants with CCS in the Latrobe Valley are expected to go ahead, but power in Queensland and New South Wales could be sourced from these different technologies. At the time of writing, Australian Government policy does not support nuclear power as part of Australia's energy mix, and it has not been considered here.

The level of uncertainty in future outcomes directly affects the location and extent of infrastructure developed in anticipation of future demand. The modelling indicated that varying transport and storage tariffs may have a significant impact on the competitiveness of different types of energy generation technologies.

In future, transport and storage costs are expected to become a factor in selecting optimal plant location. In particular, locating plant close to storage locations may become important. A good illustration is the southeast Surat emissions hub, which is located some 400–450 km from the potential Surat Basin storage areas. If the hub was located closer to the Surat Basin storage areas (i.e. within 50 km), the transport and storage tariff reduces by A\$8–10/t CO₂, to a level comparable with the low Latrobe Valley to Gippsland tariff, and the net present value of capital costs are reduced by around \$1.5 billion. The majority of the savings are a result of the shorter transport distance. Clearly, this benefit would have to be assessed together with all the other costs and benefits determined by the plant location.⁷⁰

The Taskforce recommends that any future modelling of energy futures in Australia differentiates CCS costs by location.

The different CO₂ transport and storage costs will become a factor in considering the optimal location of new plant and new energy generation hubs may emerge.

⁷⁰ Other factors include access to transmission networks, water, infrastructure, a skilled population, coal, start up fuel, and the regulatory environment.

8 INVESTMENT RISK

The commercial risks associated with carbon dioxide capture, transport and storage have been examined by a broad spectrum of stakeholders including financiers, government and industry.⁷¹

8.1 IDENTIFIED RISKS

The identified risks have been ranked using a risk consequence/probability matrix. Policy uncertainty, carbon price risk, technology risks and risks associated with integration of the whole CCS process were identified as key factors in investors' perceptions of project risk.

The major risks identified, and their brief description, are:

Policy uncertainty: The lack of a strong, consistent policy framework for an emissions price and its impact on project returns was the major risk identified. Specific elements of this risk included:

- final CPRS cap and rate of reduction of emissions,
- market volatility of carbon price under the CPRS, and:
- effect on carbon price of any Clean Development Mechanism (CDM) imports.

Concatenating risk: The risk associated with lack of integration of all the components (capture, transport and storage) and the fact that the business risks of all these components are 'chained together'.

Systems integration risk: The risk where financing of each component (capture, transport, storage) is dependent on the risk of successful implementation of the other components.

Contractual integration risk: A significant increase in counterparty risk and contractual complexities associated with interleaved 'take-or-pay' and 'send-or-pay' contracts from the various parties in the CCS chain.

Technology risk: The risk of technology not achieving the required efficiency and reliability levels, especially when all the unit operations are linked. Technology risks include:

- efficiency uncertainties in the power generation and capture components;
- reliability and operability levels in the full-scale integrated process from generation to storage;
- delay or indecision due to technological uncertainty, including the emergence of other new power generation technologies;
- uncertainties around technical optimisation of the transport pipelines and network;
- transferability of oil and gas experience to CCS; and
- insurance access for new, complex technologies.

Competing technologies risk: The risk of competing new technologies having steeper learning curves for cost reduction over time than CCS.

Early obsolescence risk: The risk of further development of new CCS technologies making the first CCS investment prematurely obsolete.

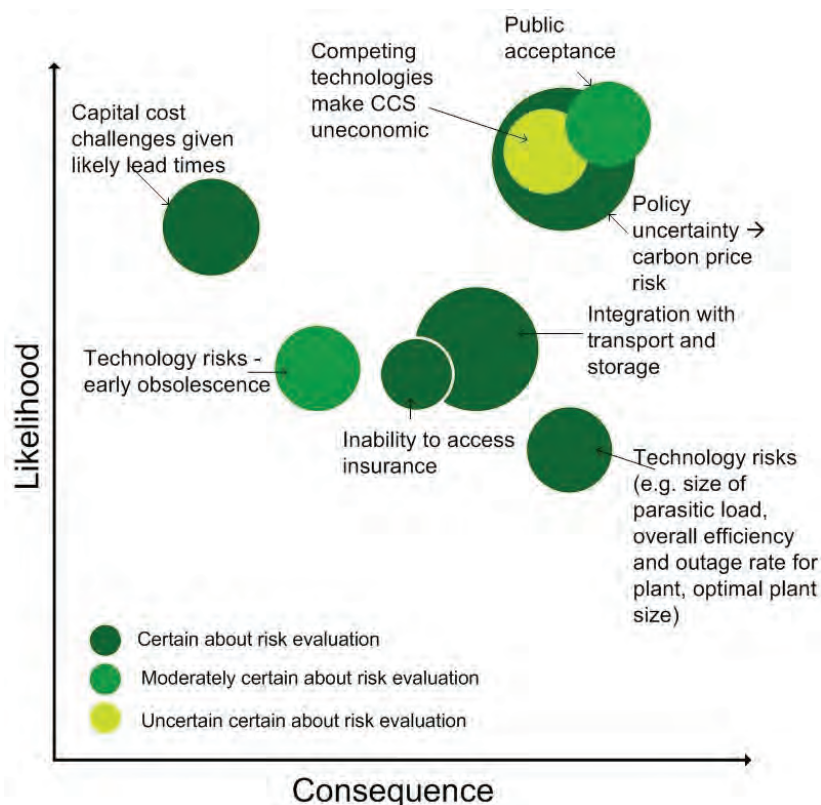
Public acceptance risk: The risk that the general public will not accept the deployment of CCS technology. This was a major risk identified by the workshop participants, with the impact of an early safety or environmental incident being seen as 'extreme'. Mitigation of community risks is covered separately in Section 12 below.

⁷¹ Deloitte Touche Tohmatsu 2009, *Project Finance Workshop Facilitation Report*, report prepared for the Carbon Storage Taskforce, Department of Resources, Energy and Tourism, Canberra.

8.2 RISK EVALUATION

Figure 37 shows the risk matrix identified for the 'Generation and Capture' component of the CCS process, Figure 38 shows the risk matrix for the 'Transport' component, and Figure 39 shows the risk matrix for the 'Storage' component.

Figure 37: Risk Analysis – Generation and Capture



Deployment of any low emissions energy technology, using renewable energy or fossil fuels, at the scale required to reliably satisfy demand, will require investments of very large amounts of capital. At present, the investment return is typically recovered over three to four decades. Larger scale investments normally generate significant economies of scale, and make costs more competitive.

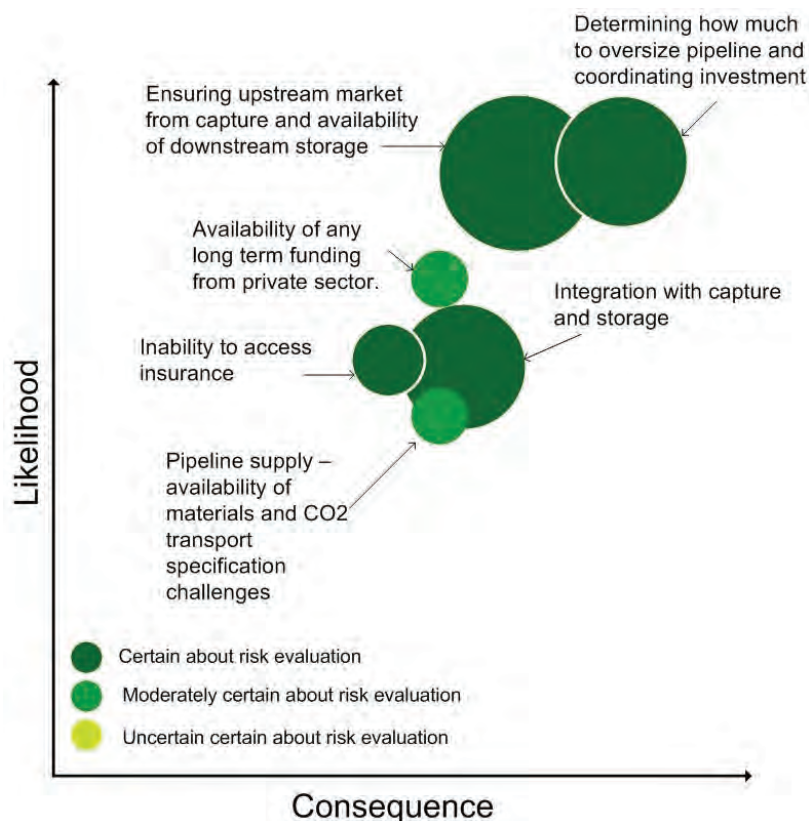
Future energy costs from any currently available generation technology appear likely to be higher than those generated currently using coal-fired power with no emissions abatement, depending on the future carbon price. Therefore, the cost and viability of various generation options could change significantly over the coming decades.⁷² This creates the risk that an asset might be stranded during its expected life, thereby substantially reducing the return on investment or generating a loss.

Investments made to reduce emissions in response to the CPRS are, on average, unlikely to reap early cash flow benefits. While carbon price and electricity prices are low there is no revenue stream, but rather an avoided cost and/or a social licence to operate. Under the CPRS, the avoided cost is likely to increase with time, rather than in the earlier stages of the project. Against this benefit profile, substantial investment to define storage reservoirs adequately is typically required for CCS projects many years in advance of a start-up date. This would normally involve higher levels of risk than construction of plant,

⁷² A wide range of factors affect the cost and viability of technologies over time, including cost reduction through development of more efficient process designs and technologies, improved material capacities, and economies of scale. Conversely, competing use for raw materials or fuels may increase costs. In energy technologies in Australia, transport infrastructure – transmission of electricity, pipelines for CO₂ and gas, railways for coal – could have a particularly significant impact. For processes requiring geological storage capacity or exploitation of a hydrocarbon fuel reserve, changes in competitiveness are primarily determined by the discovery and development of more economically attractive geological resources.

as exploration/appraisal can involve expenditure of many millions of dollars with no return. This cash flow pattern is not unique to CCS. Other energy technology responses to the CPRS at a scale capable of matching energy demand face the same challenges of large scale investment in relatively high risk projects without significant early returns.

Figure 38: Risk Analysis – Transport



Continuing liability for the impact of the injected substances for a lengthy period following cessation of injection has also been frequently raised by project proponents as an issue of great concern.

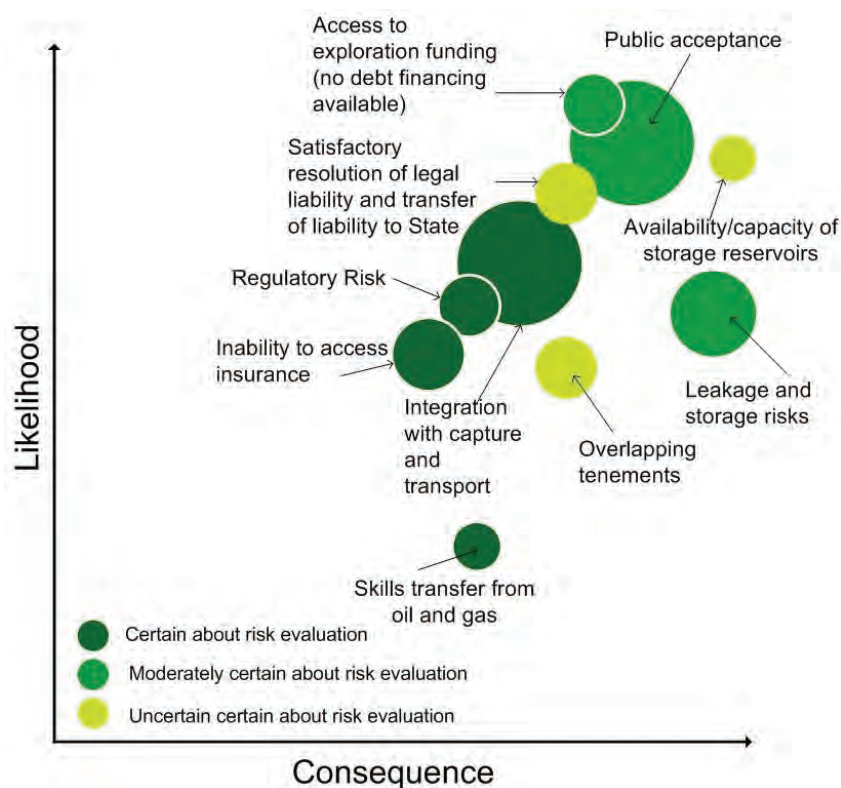
To reduce risk in responding to this uncertain future, it follows that if investment is to be made at large scale, it should be made in those assets most likely to remain low cost and competitive in any future energy generation cost portfolio. This applies to the combination of both capital and operating costs per unit of energy delivered, not just the cost for the peak power rating of the facility.⁷³ It is also important for electrical system stability reasons to ensure that most of the new generating capacity has a high utilisation rate so that it provides adequate base-load energy delivery.

Project financiers attach high levels of risk to untested integration of process elements, and also to scale up to new capacity levels. In the case of CCS, there are several elements that need to come together technically for future commercial deployment at large scale. For electrical power generation, these are

⁷³ For example, a coal-fired power plant with a 1000 MW (megawatt) nameplate capacity that delivered energy to the grid 90% of the time would deliver ~7.9 GWh (gigawatt hours) of electrical energy in a year. Solar or wind power plants would need a 3000–5000 MW capacity to match this output of delivered energy. Solar or wind power plants can only generate power between ~20% to ~30% of nameplate electricity generation capacity (on average throughout the year) because the renewable fuel source (the sun or wind) is variable or intermittent. Delivering the same amount of energy annually as the coal-fired plant will require ~3 to ~5 times the nameplate capacity of wind turbines or solar power plant to be installed, with back-up energy generators covering times when the renewable fuel source isn't available. Adding energy storage into a solar or wind power plant significantly improves the capacity factor of these plants, but this requires additional capital investment for the storage sub-system and for additional energy generating capacity to provide the stored energy and to compensate for efficiency losses in the storage system.

the power generator, the CO₂ capture facility, the pipeline, and the storage facility. The risks associated with the operability of this overall process stream at high utilisation factor and scale are at present too high for commercial investment at reasonable rates of return.

Figure 39: Risk Analysis – Storage



Capture, transport and storage will also need to be integrated contractually. Similar levels of complexity are dealt with in other industries such as petroleum, where suppliers, transporters and distributors interact. However, these relationships are based on experience that can be reasonably risked and accounted for contractually. To accelerate deployment of CCS, it is important that any differences presented by CCS are explored in the near term by industry and government so that opportunities for mitigation of risk are identified, and the contractual relationships and exposures are mapped and understood by all stakeholders. These risks will diminish with the first successful commercial-scale demonstrations of the integrated CCS process for power generation. There is currently very little appetite, if any, for commitment of private funds to first of a kind, integrated CCS operations.

8.3 RISK MITIGATION

As part of the stakeholder consultation process, mitigation strategies were developed for a number of the key risks to lower the levels of risk or uncertainty. The majority of the measures involved government and regulatory responses.⁷⁴

8.3.1 Policy Uncertainty

There was a strong view amongst participants at the Taskforce's Project Finance Workshop that government should provide a certain, long-term policy framework around carbon markets, including certainty around future carbon and electricity price levels.

⁷⁴ Participants at the workshop did not make judgement on the quality of the policy response from the Government point of view.

The level of uncertainty in revenue projections for CCS projects was seen as being much higher than for other infrastructure or large-scale technology investments. Suggested mitigation measures included:

- the use of 'take-or-pay' and 'send-or-pay' contracts;
- government underwriting of electricity and carbon prices for transport and storage (with a profit sharing arrangement); and
- government funding of infrastructure construction, especially in relation to the pipelines network for transport of CO₂.

The development of hub networks will pose significant issues for project financing. There was a view that government may need to take an active role in facilitating finance for CO₂ pipelines for hub networks.

Current laws and regulations may also pose uncertainty and will need to be clarified for CCS to become viable. There will need to be clear technical regulations, including a clear liability framework.

8.3.2 Integration Risks

Successful integration of all components of CCS is essential for high utilisation of the capital employed. This is from both the construction and operational point of view. Suggested mitigation options included having capture plants ready and in place, and effective co-ordination of the participants. Successful large-scale demonstration of integrated generation, capture, transport and storage at high utilisation rates was regarded as critical for financial risk reduction for future CCS commercial deployment.

8.3.3 Technology Risk

Although there have been a number of instances of injection of CO₂ to storage in the petroleum industry globally, CCS technology for power generation remains immature. This risk could be mitigated to an extent with one or more successful large-scale demonstration plants, integrated through to storage. However, even with successful demonstration, the level of technical risk was still seen to be relatively high, requiring commensurate financial returns.

With regard to pipeline transport, the key mitigation strategy was seen as the obtaining of contractual certainty for capture and storage participants to ensure a broad base-load and a rate of return commensurate with risks.

8.3.4 Competing Technologies Risk

Given that CO₂ abatement technologies are developing rapidly, the relative cost reduction learning curve for CCS versus other competitive new low emissions technologies could make CCS less financially viable. Mitigation strategies to reduce this risk could include power purchasing agreements, mandating particular technologies as part of the portfolio, or having a feed-in electrical tariff or credit for the CO₂ stored for CCS.

Policy uncertainty and carbon price risk were identified as a key factor in investors' perception of risk for projects that required returns on assets over several decades.

Large scale investments are required to reduce costs through economies of scale, but this creates an exposure to the risk of technological obsolescence during the life of the project.

If investment is to be made at large scale, it should be made in those assets most likely to remain low cost and competitive in any future energy generation cost portfolio.

Successful operation of a fully integrated CCS process at large scale will have the greatest beneficial impact on investors' perception of risk for CCS projects.

9 TIMING OF CCS DEVELOPMENT

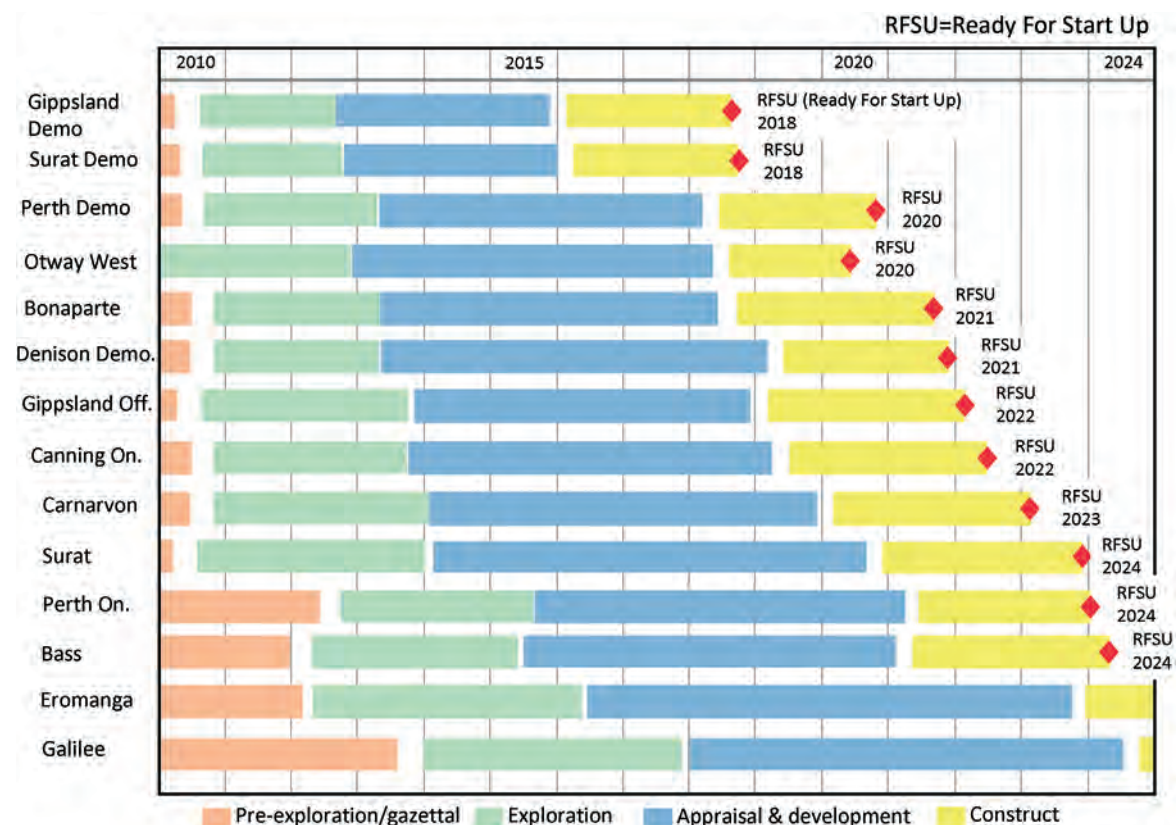
It is the experience of the pipeline industry that the projects at either end of the pipeline are more consequential to the overall project timeline than the pipeline itself. For CCS projects, it is considered that the geological storage sites will need the longest preparation time in terms of extensive exploration effort.

Overall, the Taskforce has determined that the timeframes for commercial deployment of CCS technology are long and significantly depend on the Exploration and Appraisal phases of the development timeline.⁷⁵

Basins that are well known geologically can be developed more quickly than those with poorly known characteristics. However, in those basins with insufficient information to allow the release of acreage for competitive exploration, a pre-exploration phase of between two and three years could be needed.

The Taskforce has examined the time required to mature a site for storage (Figure 40). If it is assumed that the storage construction phase is between two and three years, and that legislation is in place by the end of 2009 in order to allow release and award of acreage to storage explorers by the third quarter of 2010, then the elapsed time to mature an aquifer storage site from commencement of exploration to commencement of CO₂ storage at large scale could be between ten and thirteen years, i.e. 2020 to 2023.

Figure 40: Timing from pre-exploration to commencement of storage operations for likely storage basins and demonstration areas



⁷⁵ Accelerating broader commercial deployment of CCS will require reductions in the cost of capture through technological development, and this involves similarly long timelines.

For depleted gas and oil fields, where there is usually abundant seismic data, wells and production history, the risks associated with storage can be evaluated and understood in a relatively short time frame, i.e. by 2016. The earliest time that aquifer storage could be available for use by demonstration capture projects is around 2018. Projects that have already started an evaluation process may be able to achieve an earlier result.

Smaller sites (i.e. with smaller annual storage capacity) are relatively quick to develop (e.g. demonstration sites, Otway West, and Bonaparte) while large storage sites take considerably longer (e.g. Surat, Eromanga). Exploration and appraisal of offshore basins is accelerated by the early acquisition of 3D seismic (which is relatively low cost and fast offshore).

The pre-exploration phase could take between two and three years to complete in those basins with insufficient information to allow the release of acreage for competitive exploration. To prove up storage reservoirs to match future needs, work therefore needs to begin immediately.

It is now generally recognised within industry that developing adequate confidence in storage capacity and the resulting total cost for capture, transport and storage is the critical driver of timelines for the proposed 'early mover' 'flagship' projects. However, acceleration of broader commercial deployment of CCS will require parallel activity to establish and improve the economics of capture technologies.

Parallel activity is also required to develop assurance and expertise for decision makers determining the design, and approval criteria, for CO₂ pipelines. This work needs to begin now, so that when firm pipeline proposals are developed later in the CCS project development process, regulatory decisions can be made efficiently and effectively.

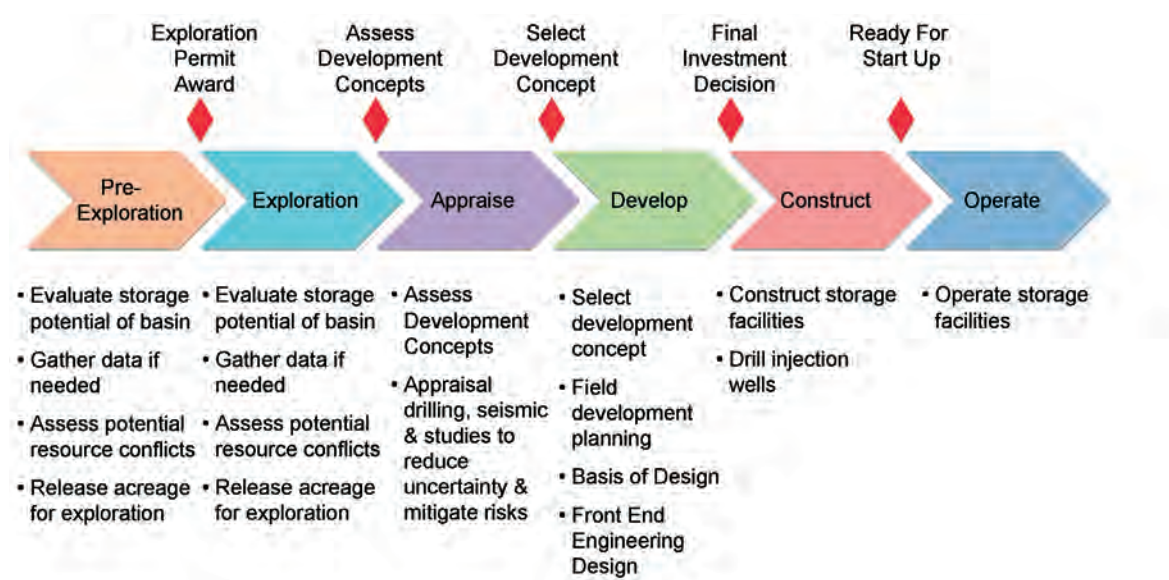
The availability and cost of services and materials are influenced by both domestic and international activities and markets, which are typically cyclic. Competition for these resources could come from widespread international deployment of CCS, increased petroleum industry activity, or more locally, extensive development of the coal seam methane (CSM) industry in Queensland. This could potentially delay power generation CCS projects for many years.

10 PRE-EXPLORATION TO DEVELOPMENT: COST AND SCALE OF THE CHALLENGE

10.1 SCOPE

The overall carbon storage evaluation process is shown in Figure 41.

Figure 41: Carbon transport and storage evaluation process



This section deals with the phases of the storage evaluation process from Pre-exploration through to Develop.

The Carbon Storage Taskforce has been asked to recommend a National Carbon Mapping and Infrastructure Plan (the Plan). The Plan addresses the pre-exploration phase of the carbon storage evaluation process. The objective of the Plan is to acquire sufficient additional data and information (ie. wells, seismic, geological, geophysical, geochemical, geo-mechanical, environmental etc) to allow the authorities to evaluate the storage potential of prospective basins to a sufficient level of confidence to allow the release of acreage for commercial exploration.

A scoping-level estimate of the activities and costs associated with the Exploration, Appraisal and Development phases has also been made. This estimate:

- provides a context to assess the costs of the pre-exploration program (the National Carbon Mapping and Infrastructure Plan);
- completes the description of the full storage 'value chain' so that costs can be attributed to all phases of the storage process;
- assesses the impact of exploration, appraisal and development costs on carbon storage tariffs;⁷⁶
- provides an estimate of the magnitude of the storage exploration and appraisal effort and benchmarks this against the activities of the Australian oil and gas sector to assess its feasibility;
- estimates the geoscience and engineering skills required; and
- finally, and importantly, allows 'realistic' schedules for the storage evaluation process of basins to be constructed so that the timing of storage capacity availability can be realistically assessed.

⁷⁶ The modelling performed to date takes no account of that part of expenditure prior to Final Investment Decision (FID)

10.2 PRE-COMPETITIVE EXPLORATION PHASE

The Storage Working Group of the Taskforce has evaluated a pre-competitive exploration technical work program that is required to make the decisions needed for acreage release.

Several strategic themes arising from the need to develop a national carbon transport and storage capacity were used to shape the overall pre-competitive exploration program. These were:

- An immediate priority is to include pre-exploration activities that encourage early development of storage to support demonstration projects by 2015–2020.
- The medium term priority is to ensure that the pre-competitive program addresses the assessment of the storage potential of under-explored prospective basins.
- The longer term priority is to have developed an adequate knowledge of basins to be able to make informed strategic infrastructure decisions when needed (ie. post-2020).

The CCS pre-competitive work is generally more detailed than would be undertaken for oil and gas exploration. The pre-competitive data needs to be sufficient to provide an initial assessment of the storage potential of basins. The pre-competitive data is used to establish whether the basin is likely to have sufficient storage potential to justify release of acreage for efficient commercial exploration and development; and that enough is known about the basin to release acreage in a way that optimises the use of its storage potential.

The pre-competitive program would evaluate the basins against four key parameters.

1. *Storage Potential* – there is a need to ensure that there is enough understanding of porosity and pore space within each basin to store the required amount of CO₂. Pore space is the main asset in a basin. The 'E' efficiency factor will also be important in dictating the final amount of storage available.
2. *Containment of CO₂* – this issue needs to be answered in terms of the integrity and morphology of the capping seal, especially in relation to regional-wide scale effects and potential migration CO₂ paths through or beneath the seal. Transport and pressure effects related to storage rock permeability will also be important. Ongoing measurement and modelling and regional-scale oversight will thus be required.
3. *Maximising Storage* – geological knowledge is needed on strategies for maximising the CO₂ storage asset, given the basins available. This optimisation process needs to include factors such as the timing order in which the basins should be utilised and the optimum matching between the sources and sinks and to guide activities such as acreage release.
4. *Resource Conflict* – geological knowledge is required for guiding policy decisions, especially in relation to resource conflicts (e.g. basin use for extraction of other hydrocarbons, fresh water, geothermal heat, coal seam methane extraction, underground coal gasification, etc).

Data quality from pre-competitive work needs to be sufficient for informed decision-making in all of these issues, with a balance between adequate knowledge and regulatory and legal requirements.

Using the ranking of Australian basins developed by the Taskforce, in combination with the strategic and technical considerations outlined above, a program of pre-competitive exploration work has been defined for the Galilee, Surat, Eromanga, Clarence-Moreton, Darling, Sydney, Gunnedah, Oaklands, Gippsland, Torquay, Bass, Otway, Perth and Esperance basins.

The Taskforce has defined a coherent three-phase pre-competitive exploration technical work program that is required to make the decisions needed for acreage release. Outcomes of earlier phases will potentially modify specific elements of subsequent phases. The Phase 1 program costs \$84 million. Phase 2 would cost a further \$46 million and the Phase 3 activities would cost \$124 million. The total pre-competitive exploration program of \$254 million is far in excess of the original \$50 million provided by the Commonwealth. It should be noted that this funding was proposed by the Commonwealth on

The program, which has already commenced in some jurisdictions, is expected to be implemented over five years. Figure 42 below shows the geographical and exploration scope of the program. The activities and estimated costs are summarised in Table 7.

LEGEND

- Priority 1: \$84m
- Priority 2: \$46m
- Priority 3: \$124m
- 7000 7000km seismic reprocessing
- 195 190km seismic acquisition
- 1+1N 1 well + 1 observation well

Map of Australia showing the distribution of seismic and well data for the 2015-2016 period. The map is color-coded by priority: Priority 1 (blue), Priority 2 (orange), and Priority 3 (red). The legend on the left explains the symbols: Priority 1 (\$84m), Priority 2 (\$46m), Priority 3 (\$124m), 7000km seismic reprocessing (R), 190km seismic acquisition (195), and 1 well + 1 observation well (1+1N). The map shows various seismic acquisition areas (195, 7000, 2+2N, 1+3N, 2+1N, 2900, 2540, 1800, 2200, 6000, 5000, 6000) and well locations (1, 2, 3, 4, 6). A scale bar at the bottom indicates distances from 0 to 1,000 km.

Table 7: Recommended Pre-exploration Program

BASIN	STATE	DRILLING	SEISMIC	OTHER	STUDIES	COST \$M
PHASE 1						
All				National Database		3
Sydney	NSW	4 wells	2000km offshore 2D 540km onshore 2D			11.5
Darling	NSW	4 wells				20
Bass	Tasmania		6000km reprocessing	Interpretation	3D basin framework, hydrodynamic model, petroleum & CO ₂ models etc	0.8
Galilee	Queensland	2 well + 2 Nested	7000km reprocessing 195km onshore 2D			20
C-Moreton	NSW	3 wells	325km onshore 2D 2900km offshore 2D	Gravity		28.5
Total Phase 1		15 wells	13000km reprocessing 4900 km offshore 2D 1060km onshore 2D			83.8
PHASE 2						
Surat (South Central)	Queensland	1 well + 3 Nested				14
Gunnedah	NSW	2 wells				10
Gippsland onshore	Victoria	6 wells	1800km onshore 2D		3D basin modelling	15.3
Perth onshore	WA	2 wells			Lower Leseur	5
Canning onshore	WA				Browse-Canning study	1.5
Esperance	WA				Study	0.6
Total Phase 2		14 wells	1800km onshore 2D			46.4
PHASE 3						
Surat (East Central)	Queensland	1 well + 1 Nested				8
Surat (Roma)	Queensland	1 cored				6
Galilee	Queensland		195km onshore 2D			2
Eromanga	Queensland	1 cored	665km onshore 2D			13
Darling	NSW	4 wells	650km onshore 2D	K modified		20
Gippsland offshore	Victoria	2 wells	2200km offshore			46
Torquay	Victoria	2 wells	5000km reprocessing	Interpretation	3D basin modelling	20.7
Otway East	Victoria		6000km reprocessing		3D basin modelling	0.6
Oaklands	NSW	1 well	325km onshore 2D			5
Otway	SA				Baseline seismicity, biota	1.5
Carnarvon	WA				Barrow Island EOR	0.75
Total Phase 3		13 wells	11000km reprocessing 1835km onshore 2D			123.55
Total Phase 1,2,3		42 wells	24000km reprocessing 4695km onshore 2D 4900km offshore 2D			\$253.75

There needs to be a focus on pre-competitive work at the regional scale level by governments; the prospect-scale is where private industry operates. Future work includes developing a comprehensive geographic information system (GIS) database with a standard format to ensure that ongoing work is sustainable and useable in the future.

10.3 EXPLORATION PHASE

An estimate of the magnitude of exploration activity, and its cost, has been made. The estimate draws on the data derived in the assessments of Australian basins and summarised in the basin montages. The estimation process has four elements.

1. Identification of the suite of basins most likely to provide the storage sites for the emissions hubs that have been identified by the Taskforce.
2. Estimation of the 'storage area' required for a targeted annual storage capacity. This, together with any statutory (relinquishment) mechanism, informs the estimation of the exploration lease area.
3. Estimation of the Exploration phase activities and costs, based on desired well and seismic spacing, taking account of existing seismic and well spacing and geological complexity.
4. Estimation of the probability of finding a storage site in the basin. This defines the number of exploration permits needed to give an acceptable probability that the target annual storage capacity is identified.

Further details of the methodology employed and the accompanying data are given in Appendix G.

10.3.1 Modelled Basins

Exploration activity and cost estimates have been made for the hub/sink combinations identified from the basin rankings and Australian CO₂ emission sources discussed previously (see Table 8 below). The annual storage requirement target is derived from projected CO₂ emissions in 2020, with the assumption that 90% of emissions from coal-fired power generation and 100% of CO₂ in reservoir gas from LNG developments are to be captured.

Several 'boutique' storage basins for the early demonstration of commercial scale CCS have also been included. The purpose in evaluating these is to assess the likely timeframe in which storage for demonstration projects can be established. The demonstration sites modelled are locations where there are known candidates for commercial demonstration of capture technologies and are assumed to have a capacity of 3 Mtpa CO₂.

Table 8: Potential storage basins and hubs modelled for exploration, appraisal and development activities and costs

POTENTIAL STORAGE BASINS	CAPTURE TARGET	HUB
Galilee	16 Mtpa	Gladstone, Rockhampton, Biloela
Surat	50 Mtpa	East Surat, Hunter Valley, Newcastle
Eromanga	34 Mtpa	Gladstone, Rockhampton, Biloela, East Surat
Gippsland	31 Mtpa	Latrobe Valley, NSW West, Lithgow
Bass	18 Mtpa	Latrobe Valley
Otway West	5 Mtpa	Otway West
Perth onshore	10 Mtpa	Perth, Collie, Kwinana
Canning onshore	7 Mtpa	Kimberley LNG hub
Carnarvon	9 Mtpa	North West Shelf LNG projects
Bonaparte	5 Mtpa	Darwin LNG projects
DEMONSTRATION		
Gippsland onshore	3 Mtpa	Latrobe Valley project
Roma Shelf	3 Mtpa	Surat East project
Denison Trough	3 Mtpa	Gladstone project
Perth onshore	3 Mtpa	Perth North project

The total targeted annual commercial storage requirement from the above table is 197 Mt per year.

The focus on activity in the Exploration Phase (shown in Figure 41 above) is on finding a storage site. This means developing a 'storage play concept' through basin studies, reviews of existing data, seismic reprocessing and acquisition etc, and then testing the concept through drilling a series of wells aimed at proving that it is likely to be viable. There may be several storage site possibilities within an exploration lease area.

10.3.2 Storage Area

The nominal area required per basin/demonstration site in order to store CO₂ has been calculated using the basin parameters derived by the Taskforce in calculating the basin storage capacity and the injectivity parameters for specific representative locations within these basins, as discussed in Section 4 above. These parameters are also reported on the basin montages. A multiplier of two times the calculated storage area has been used to estimate permit sizes, but permits may need to be even larger than calculated to account for the potential migration paths of the CO₂ (possibly ten times). This would imply that the estimates of permit areas and exploration activities are optimistic and exploration costs could be even greater than the estimates herein.

It is interesting to note that for some basins, such as the Galilee, the storage area is large for relatively modest injection rates, whereas basins such as Gippsland have a very concentrated storage area. This suggests that basins with thicker reservoirs will have a more commercially efficient outcome.

10.3.3 Exploration Activity

The intensity of exploration activity is largely a function of the geology of the basin (its complexity and variability) and the knowledge and data that already exists. If the reservoir or seal are thin, drilled well and seismic data needs to be acquired at a closer line spacing than for a thick reservoir and seal because of the potential for faulting and/or facies⁷⁷ variations to impact on reservoir continuity or seal integrity.

⁷⁷ Facies: a body of sedimentary rock distinguished from others by its lithology, geometry, sedimentary structures, proximity to other types of sedimentary rock, and fossil content, and recognized as characteristic of a particular depositional environment.

The approach used to estimate activity levels uses the existing seismic and well data in each basin. Where there is abundant data, less new data needs to be acquired. Conversely, where data is sparse, more new data is needed. The approach is statistical, using the number of wells in the basin (exploration and appraisal) to calculate how many wells are likely to be present in the storage exploration lease.

Based on the knowledge of the work already done, an estimate can be made of how much seismic data is present in the lease and therefore how much reprocessing is required. Similarly, by having a target line spacing for the exploration lease and knowing the area, the amount of additional seismic acquisition can be estimated. For offshore permits, this may be 3D seismic.⁷⁸

Table 9 shows the estimates of required exploration drilling and seismic activities per basin, given the existing knowledge of the basin and taking into account the information on each basin presented in the basin montage described previously.

Table 9: Estimated exploration drilling and seismic activities per basin

	EXISTING WELLS	EXISTING SEISMIC LINE SPACING (km)	ESTIMATED EXISTING WELLS IN LEASE	ESTIMATED EXISTING SEISMIC (km)	REQUIRED WELL SPACING (km)	REQUIRED SEISMIC SPACING (km)	NUMBER OF EXPLN WELLS TO BE DRILLED	SEISMIC ACQUISITION (km/km ²)	CORE PER WELL (m)
Galilee	128	20	17	400	20	4	10	4000	90
Surat	1229	5	103	1340	30	4	4	1670	36
Eromanga	2023	4	177	1750	30	5	4	1400	54
Gippsland	310	0.5	20	4090	30	3D	1	700 km ²	54
Bass	35	1	7	5570	30	0.5	3	1490	90
Otway West	91	5	5	130	15	3D	1	600 km ²	54
Perth onshore	57	5	16	480	30	2	1	1200	54
Canning onshore	229	10	8	250	20	4	3	630	90
Carnarvon	868	0.5	25	6270	15	3D	7	600 km ²	36
Bonaparte	388	0.5	2	1300	15	3D	1	600 km ²	90
Gippsland onshore demo.	10	10	0	70	20	3D	1	370 km ²	90
Roma Shelf demo.	1229	5	12	150	20	4	1	190	90
Denison Trough demo.	40	10	3	170	20	2	2	870	90
Perth onshore demo.	57	5	16	480	20	4	1	600	54

⁷⁸ The area of 3D seismic to be acquired is set by the assumption that an operator would need to have 3D data available at least over the injection area, so that an adequate reservoir model can be constructed. The injection area is calculated from the number of injection wells and well spacing, which are determined by coarse reservoir simulations made as part of estimating the carbon storage tariffs.

10.3.4 Exploration Risk

In modelling exploration expenditure, it is necessary to consider exploration risk. A storage explorer may take up a lease, but after drilling several wells may find that the geology in the lease is not suitable for storage, the seal may not be effective, and so on. In addition to this geotechnical risk, other risks such as landowner access or areas of special environmental significance also result in fewer exploration leads being available than are desired.

As discussed in Section 4 of the report, Bachu (2003) developed a tool for the assessment and ranking of sedimentary basins for their suitability for CO₂ storage. This ranking methodology was modified for Australian basins. The criteria, weightings, scoring and overall score in terms of probability of success (POS) for each exploration basin is summarised in Table 10 below.

Reservoir (depth, quality) and seal (faulting intensity, quality) are important in the criterion weightings.⁷⁹ If the reservoir and its seal is poor, the risk for the explorer is that the reservoir may not be adequate for storage or the seal may leak. Knowledge of the basin and availability of information/data contribute further to the weightings. Where there is less knowledge and data, the uncertainty and cost risk for the explorer is greater. It can be argued therefore that the modified basin ranking is a measure of the basin's storage potential or chance of success ie. the higher the score, the greater the chance that a storage site is present in the basin. The question then is how to translate the Bachu score to a POS. For this study, a 'rule of thumb' has been applied.

The highest scoring basin in Australia is the prolific oil- and gas-producing Gippsland Basin, which scores 3.94 in the rankings (the maximum score possible is 4.17). The Gippsland Basin is a strong candidate for CO₂ storage and the chance of finding a storage site is very high. The lowest basin score is around 2.0. By assigning a 0% Probability of Success (POS) to a score of 2.0, and a POS of 75% to a score of 4.17, the modified Bachu score has been converted to Probability Of Success.

The POS results are included in Table 10. As can be seen, the prolific oil and gas basins have the best chance of success. The Gippsland Basin has the highest POS of 67%, followed by Carnarvon at 57% and Eromanga at 53%. The Galilee Basin, which has large unexplored areas, has the lowest POS at 33% (or a one in three chance of finding a storage site). This means that in the Galilee, three exploration leases would be needed to deliver one storage site, on the basis of probabilities. In this way, the POS and modelled injection capacity are used to calculate the number of exploration leases required in each basin to achieve the target storage capacity.

⁷⁹ Amounting to 68% of the weighting factors.

Table 10: Criteria, weightings, scoring and overall score and probability of success (POS) for each exploration basin

CRITERION	SIZE	DEPTH	TYPE	FAULTING INTENSITY	HYDRO- GEOLOGY	GEO- THERMAL	HC POTENTIAL	MATURITY	RESERVOIR	SEAL	RES/SEAL PAIRS	KNOWLEDGE LEVEL	DATA AVAILABILITY	SCORE
WEIGHTING	0.06	0.10	0.04	0.14	0.04	0.05	0.05	0.05	0.16	0.18	0.03	0.05	0.05	POS
Galilee	Large	Intermed.	Non-marine & marine	Moderate	Good	Warm	Medium	Developing	Poor	Poor	Excellent	Moderate	Moderate	2.93 32%
Surat	Large	Deep	Non-marine & marine	Extensive	Good	Moderate	Small	Mature	Good	Good	Excellent	Good	Good	3.13 38%
Eromanga	Large	Deep	Non-marine & marine	Moderate	Good	Warm	Large	Over-mature	Good	Good	Excellent	Extensive	Excellent	3.54 53%
Gippsland	Large	Deep	Non-marine & marine	Limited	Good	Moderate	Giant	Over-mature	Excellent	Excellent	Excellent	Extensive	Excellent	3.94 67%
Bass	Medium	Deep	Non-marine & marine	Moderate	Intermed.	Moderate	Medium	Exploration	Good	Good	Excellent	Good	Good	3.09 37%
Otway West	Medium	Deep	Non-marine & marine	Extensive	Intermed.	Moderate	Medium	Developing	Good	Good	Excellent	Good	Good	3.00 34%
Perth onshore	Medium	Deep	Non-marine & marine	Moderate	Good	Moderate	Large	Mature	Poor	Good	Excellent	Good	Excellent	3.14 39%
Canning onshore	Very Large	Deep	Non-marine & marine	Moderate	Good	Moderate	Medium	Exploration	Good	Good	Excellent	Moderate	Moderate	3.01 35%
Carnarvon	Very Large	Deep	Non-marine & marine	Extensive	Intermed.	Moderate	Giant	Over-mature	Excellent	Good	Excellent	Extensive	Excellent	3.66 57%
Bonaparte	Very Large	Deep	Non-marine & marine	Extensive	Good	Moderate	Large	Developing	Excellent	Good	Good	Good	Good	3.22 42%
Denison Trough	Medium	Deep	Non-marine & marine	Moderate	Good	Cold	Large	Mature	Potential	Good	Excellent	Good	Good	2.97 33%

10.4 APPRAISAL AND DEVELOPMENT PHASES

During the Appraisal phase of the carbon storage evaluation process (shown in Figure 41 above), activities are directed towards assessing development concepts and gathering sufficient data to understand the uncertainties and risks. Typically, a higher degree of seismic and well control is needed, as is a detailed analysis of core data, understanding of the reservoir and seal capacity and characteristics, rock chemistry, the structural framework and geo-mechanical characteristics and hydrodynamics of the system. A full understanding of possible resource conflicts, environmental and stakeholder issues will also be needed in this phase.

In the Develop phase of the carbon storage evaluation process, the final development concept is selected from the options identified during Appraisal. A detailed development plan is then developed that is underpinned by detailed understanding of the reservoir characteristics, uncertainties and expected performance based on extensive reservoir simulation. This is a significant piece of work and is manpower-intensive.

Once the development plan is completed, the Basis of Design is prepared, followed by the Front End Engineering Design (FEED). This activity is engineering-intensive.

Appendix H gives further details of the people and other resource requirements for the Appraisal and Development phases of the CCS development process. The costs outlined below have been determined from these estimates.

10.5 EXPLORATION, APPRAISAL AND DEVELOPMENT ACTIVITIES AND COSTS

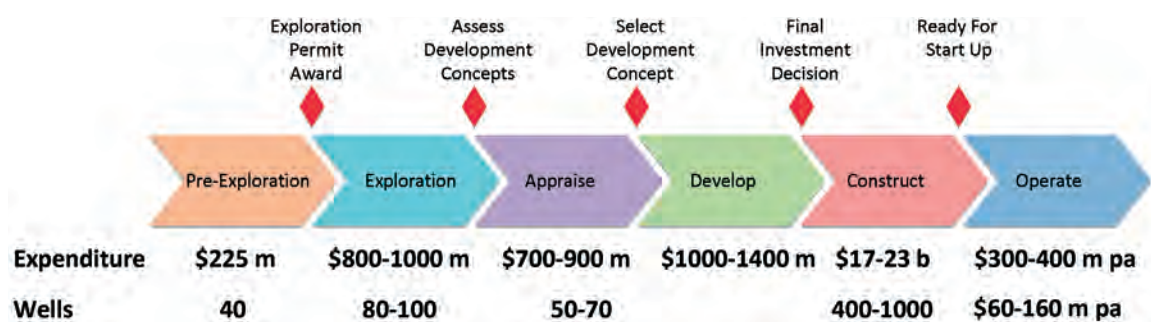
The cost associated with the Explore, Appraise and Develop phases for ~198 mt per year storage capacity for CCS is estimated to be in the order of \$6.1 billion, split roughly equally over the three phases (Exploration – \$1,872 million; Appraisal – \$2,058 million; and Development – \$2,203 million). This level of investment would be required to explore and develop storage sites for Australia’s major hubs and to also progress up to four demonstration sites in terms of storage.

The level of drilling and seismic activity is estimated to be in the order of 130 exploration wells, 100 appraisal wells, and acquisition of 60,000 km of 2D seismic and 14,000 km² of 3D seismic.

Benchmarking this activity against the Australian oil and gas industry activity level suggests that this is generally achievable in a reasonable timeframe, with the exception of onshore seismic acquisition, which would represent a dramatic increase over current levels. It is important to note that CCS activity would be in addition to ongoing oil and gas industry activity, and so increase demand for similar resources.

The full storage ‘value chain’ for the carbon storage evaluation process for the eastern seaboard is shown in Figure 43 below.

Figure 43: Value chain for storage development – eastern seaboard of Australia⁸⁰



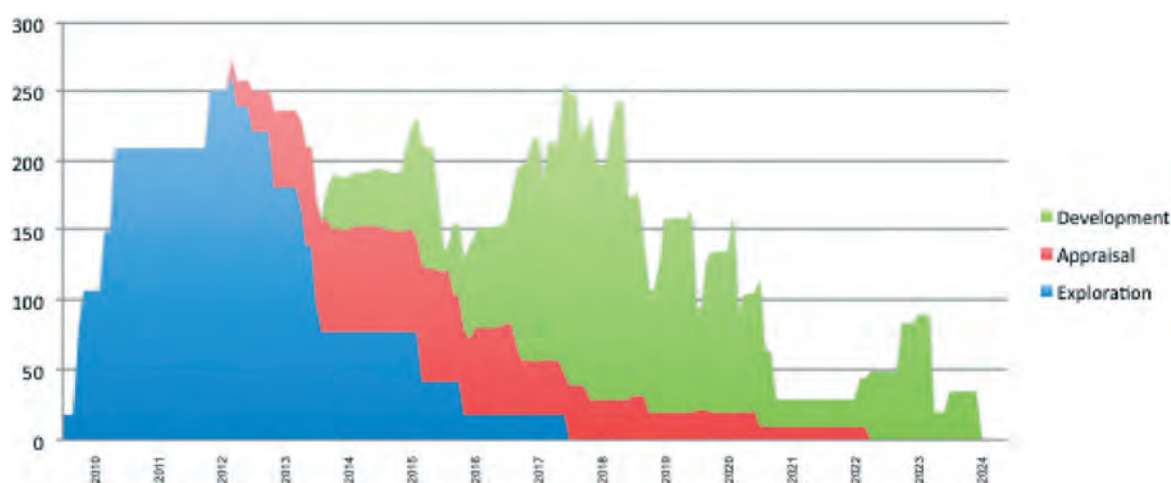
⁸⁰ For an explanation of the elements of the value chain, refer Glossary under ‘Storage Development’

Pre-exploration costs represent about 25% of exploration costs. Investment in storage prior to FID (the point at which a storage and transport operator decides to invest in building facilities) is some \$2.5 billion, which is equivalent to about 15% of the final transport and storage capital investment. This pre-investment has not been included in the estimates of storage tariffs. However, sensitivity analyses show that these costs increase the tariff by approximately 12%.

10.6 HUMAN RESOURCES REQUIRED

An assessment of the people and skills required during the exploration to development phases indicates a sustained requirement for around 200 geoscientists, petroleum engineers and engineers over the period from 2011 to 2020. This requirement is shown in Figure 44. This ramp-up of staff cannot be built from the new graduate market, but will need to be attracted largely from the oil and gas industry. Some skills such as reservoir engineering, inorganic geochemists, geomechanics / structural geologists and production technologists / completions engineers are in short supply. This estimate does not include drilling, seismic and other contractor services staff.

Figure 44: Human resource projections for the exploration, appraisal and development phases of CCS



10.7 CO₂ PIPELINE CONSIDERATIONS

There is currently only ~300 km of steel pipeline greater than 36" in Australia, comprising five pipelines, two of which are 104 km long. They are all proprietary pipelines, either being large trunklines for the North West Shelf project, or essentially short pipelines that act as long storage vessels for gas power stations. Including 34" pipeline, there is an additional 1,250 km – 1,198 km of which is the Moomba to Sydney gas pipeline. Previous periods of pipeline construction are evenly spread from 1969 to present.

This contrasts rather starkly with the projected future pipeline requirements for CO₂ transport. There is a future need for more than 5,000 km of 34–42" transport pipeline to be constructed on the eastern seaboard alone, over the period 2020 to 2035. This estimate does not include flowlines within the storage sites, which are estimated to be almost 5,000 km of smaller diameter pipe.

While there is likely sufficient industry capacity to construct this transport and distribution network, the capacity of pipeline manufacturers to construct sufficient large diameter (>34") is a major concern and is likely to be a constraint, particularly if other countries are also deploying CCS. Currently there are many smaller scale manufacturers internationally, but their quality standards do not match Australian standards. However, they could be brought up to adequate standards and capacity with appropriate investment, and thereby meet demand earlier than relying entirely on greenfield construction.

The projected level of exploration and development activity associated with storage of CO₂ is achievable and benchmarks favourably with current levels of oil and gas activity.

The generally long distances between emissions hubs and storage basins means that more than 5,000 km of large diameter pipeline infrastructure is needed to transport CO₂. This is more than three times greater than Australia's current inventory of large diameter steel pipeline.

11 ROLE OF GOVERNMENT IN SUPPORT OF GEOLOGICAL STORAGE OF CO₂

The geological storage of CO₂ is different from extractive resources in that it involves injecting, rather than removing, fluids into the subsurface to store them over geological time. This fundamental difference leads to important considerations in making areas available for CO₂ storage exploration and development.

Firstly, there is no custody transfer of the resource i.e. storage capacity. The pore space remains the Crown's, unlike minerals or petroleum where ownership is transferred at some stage of production. Secondly, there is a significant public benefit from reducing CO₂ emissions. Thirdly, there will be an ongoing need for regional geological oversight or monitoring in areas where there is injection, particularly where one or more parties are involved. Finally, the sequencing of access to the pore space may require additional consideration.

The evaluation of CO₂ storage must consider three major technical factors. The first and by far most important factor is containment of CO₂ i.e. that injected CO₂ remains stored and is not likely to leak back to the surface or into other subsurface resource areas. The second factor is the storage capacity of the area. The final factor is the injectivity or the rate at which CO₂ can be injected without impacting on the containment.

11.1 PRE-TENEMENT GRANT

When issuing rights for the first time in an area for conventional extractive resources, the primary considerations are the cost of extraction, offset of investment risk, and the environmental impact of development. By contrast, in CO₂ storage, there must be a broad and clear understanding of the parameters for optimisation of the resource. The pore spaces and their spatial distribution and 'interconnectedness' need to be understood at a regional level to ensure that the site sequencing for injection does not substantially reduce the ultimate storage potential of the basin. It is typical in most resource exploration that the best or largest resource is explored first. For CO₂ storage, however, meeting threshold criteria (e.g. proximity to sources, access, etc.) may take precedence over accessing the best storage.

Prior to release of areas, existing and potentially new geological data need to be assessed to determine fundamental questions associated with the presence and distribution of seal (for containment) and porous (reservoir) rock (for storage volume). Secondary parameters to be evaluated include the existence of suitable trapping mechanisms, such as in aquifers or depleted oil or gas fields. There is an expectation that areas will not be made available that have little or no prospect of effectively storing CO₂.

Non-geological factors will also need to be taken into account including community stakeholders, emission source sink matching, infrastructure, land use, existing tenements, and impact on other resource occurrences. Additional work is also required in jurisdictions where there is a potential for resource conflict. This includes understanding the fluid dynamics of potential storage basins involving oil, gas, potable and saline waters.

Simulation modelling of the CO₂ plume would assist in defining minimum acceptable size of tenement where the basin geometry or structure does not define the limits of migration. Alternatively, large sized initial tenements may be defined that will reasonably contain the anticipated volume of CO₂.

11.2 POST-TENEMENT GRANT

There is a strong need for ongoing regional geological assessment of the impacts of injection during the course of the life of an injection program, as well as for an area that has been retired from injection. This need again differentiates carbon storage from the hazard and safety oversight in more conventional

extractive resource exploitation which largely requires engineering expertise to ensure public and worker safety.

The cumulative impacts of injection will need to be considered from one or more injection sites, particularly if more than one injecting party is involved. Identifying the CO₂ source, as has been advised by previous research, will also be important in ensuring 'accountability' for CO₂.

Monitoring areas near the limits of basins should mitigate against seal break-through. Geoscience data captured at the exploration, development and injection stages will inform future projects and long term risk assessments.

Skills development is required within the authorities, particularly in engineering, fluid migration modelling, and seismic techniques and interpretation. These skills need to be enhanced and accelerated to ensure the nation is storage ready.

11.3 ACCESS TO DATA

The impact of large scale injection of CO₂ needs to be understood across the whole of the basin. The ability to forecast and monitor the impact of injection is greatly enhanced by having the fullest possible information on a range of factors. In basins with multiple operators, information can be obtained from existing wells on a range of relevant factors. This is particularly the case for wells that extend to the same depths as those used for CO₂ storage, e.g. petroleum and geothermal wells. Additional data, particularly outside any producing fields, is often surprisingly sparse and may need augmentation even in successful resource-rich areas.

While existing permit holders typically have advanced knowledge of their reservoirs, the available or publicly available basin data beneficial for CCS assessment and implementation is limited. This data is essential to the regulator, given the need for the regulator to develop a deep knowledge of the basin's geological framework, reservoir and seal distributions and connectivity, and hydrology, in order to optimise the basin's storage capacity. This is an issue faced internationally, not just in Australia.

It is important that both the new, increased need in the requirement for data for CO₂ storage management, and the commercial sensitivity of some of this data, is recognised. Data reporting and regulations need to be reviewed to ensure that CCS regulators are able to consult relevant data. The degree of release of data into the public domain should also be reviewed separately, as part of this discussion. It is essential that this review takes place in close consultation between industry and governments.

The Taskforce recommends that the Upstream Petroleum and Geothermal Subcommittee (UPGS), working closely with the Chief Geologists' Committee, prepares a report on issues related to data management for regulators specifically relating to injection and storage of CO₂, by the first quarter of 2010. Industry should be consulted as part of the report process. Recommendations should be made by the UPGS to the MCMPR in the first half of 2010. The composition of the current UPGS should be assessed to see if all jurisdictions have members with appropriate CCS policy responsibility.

The objective is that both governments and industry form a clear understanding of the data types and sources relevant to basin management for CO₂ storage, and government policy and requirements in relation to provision of this data.

12 COMMUNITY ACCEPTANCE

The Taskforce examined potential community concerns about carbon storage issues, and investigated potential approaches for addressing them.

12.1 POTENTIAL COMMUNITY CONCERNS

A workshop was convened with environmental NGOs (eNGOs), which sought to identify their position in relation to CCS. The participants expressed support for a portfolio approach to climate change mitigation, and not treating CCS as a 'silver bullet' or a competitor of renewable energy. Participants also expressed a need for government and industry to promote the urgency of climate change, and a portfolio approach to mitigation, including energy efficiency. They felt that this would also help to raise awareness of the need for action at the general public level. There was concern that some stakeholders would not appreciate the scale of infrastructure required for CCS, or the timelines involved in CCS projects. The findings suggest that information about CCS should be increased to reduce concerns about the technology, in a form that is readily accessible and easy to understand.

Media reporting of CCS since 2007 in most major newspapers, radio and television media was analysed. It was found that there was a fairly even balance of positive, negative, and balanced/neutral articles, but the news articles rarely contained technical explanations. Recurring themes include: the importance of coal to Australia's economy and the consequential importance of CCS; that CCS is technically possible but needs financial support from government; that CCS investment diverts important funds from other mitigation strategies; and that CCS should be funded by industry and not by taxpayers. The findings suggest that a more proactive approach should be taken, by engaging journalists and mainstream media. CCS should be promoted as 'low emission' instead of 'clean coal', because of its far-reaching applications in non-coal industries.

The Taskforce also reviewed the increasing body of analyses and experiences relating to community concerns and communications in Australia and internationally. Opinions, concerns and awareness vary widely, between opposite extremes. In some instances, landholders have welcomed the potential for construction of CCS related infrastructure for the economic benefits it provides. Conversely, some parties only consider investment in renewable energies, and appear unwilling to even consider any information describing a role for fossil fuels. More generally, the level of understanding of CCS technologies, or of any other energy generation technology, or response to climate change, is superficial across wider society. Ashworth⁸¹ et al. found that acceptance grew following provision of objective factually based technical information in an open and transparent manner.

Some key issues or concerns that emerged from this review, which need to be addressed include:

Funding: There is concern that allocation of funding to develop low emissions energy technologies is disproportionately supporting coal-fired power, rather than renewable energy technologies. The Australian Government's announcement of the Clean Energy Initiative went some way towards addressing this concern.

Technology: Many people hold a belief in the efficacy of solar power and renewables as a solution for Australia, which is not matched by an understanding of the current capacity of these technologies to meet energy demand, and the full costs and risks of deploying these technologies, relative to alternatives. There is a need to convey information on the costs of any proposed technology, including CCS, relative to the costs of pursuing other alternatives. The evaluations currently being undertaken as part of the development of the Energy White paper may provide useful data for dissemination.

Impact on power costs: Generally, there is limited understanding that introduction of low emissions energy technologies will make power costs in Australia more expensive. There has been widespread

⁸¹ Ashworth P et al 2007, *An integrated roadmap of communication activities around carbon capture and storage (CCS) in Australia and beyond*, Report no. P2007/975, Centre for Low Emission Technology, Pullenvale

reporting of the view that the CPRS will have a negative impact on the economy and cause job losses. Factual, verifiable information on best estimates of costs forecasts need to be made available in a transparent manner as part of the debate.

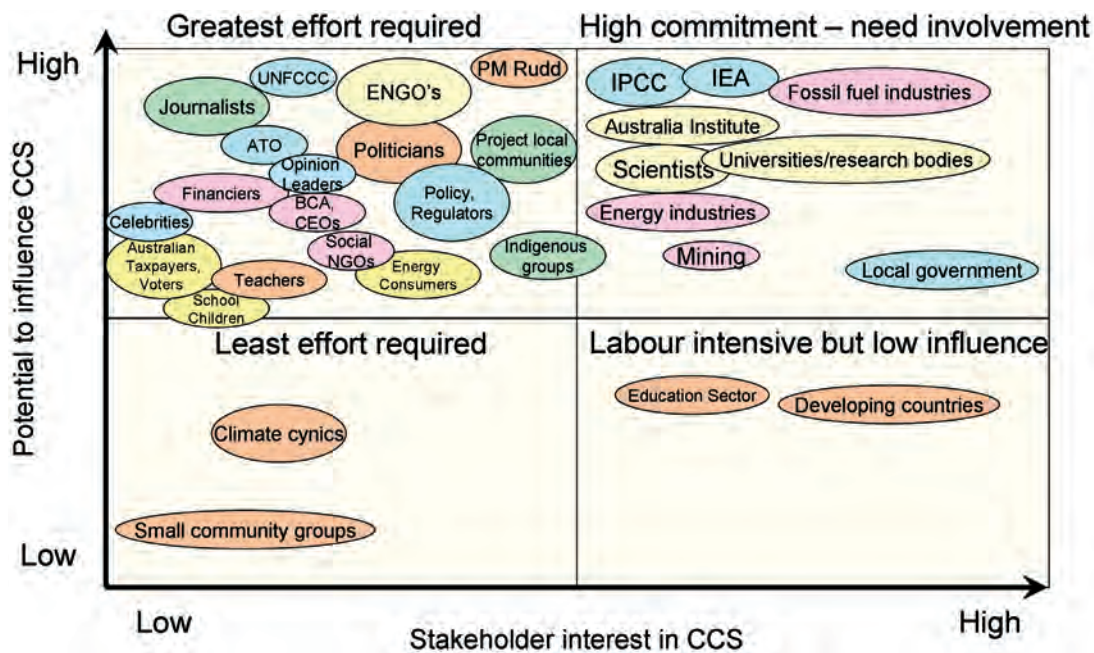
NIMBY (Not In My Back Yard): To date, project proponents in Australia have been successful in engaging with stakeholders that might be affected specifically by a CCS project. In some instances, the project was welcomed for the economic benefit it provided to a local community. However, there are some instances overseas where projects onshore are meeting strong local resistance. There is a need for transparency on the risks relating to CO₂ pipeline construction and operation, and how these can be adequately and safely managed. Storage onshore will require a similar level of assurance. Storage offshore will not directly affect landholders, apart from the transport infrastructure, however other stakeholders with an interest in the oceans will need to be consulted.

12.2 RESPONSE

12.2.1 Stakeholder Engagement

The Taskforce investigated potential approaches to engage with influential stakeholders, as well as actions that would address community concerns more widely if required. A map and categorisation of stakeholders is identified in Figure 45 and a summary of the recommended communication activities is given in Appendix B. This Appendix also specifies a suggested program for engagement for each stakeholder.

Figure 45: Map of key stakeholders for developing a communication strategy



12.2.2 Coordination

An engagement strategy needs sponsorship, funding and management to be implemented. A centrally controlled strategy for CCS communications in Australia seems unlikely, given the disparate and conflicted range of CCS stakeholders, and the need of each stakeholder to control its engagement with its audience. To date, individual project proponents have managed their interaction with their stakeholder group successfully. At the wider community level, statements on CCS have been made independently by, amongst others, governments, politicians, environmental NGOs, prominent individuals, the CSIRO and the CO₂CRC. The Australian Coal Association (ACA) has invested substantially in developing a website and schools' curriculum program. The CO₂CRC has provided information on CCS in many forums for some years. The intention is also that the GCCSI will play an increasingly important role in CCS communications.

This ad hoc model might continue to be adequate, but the opportunity for coordination should also be evaluated, particularly if more widespread campaigns opposing low emissions fossil fuel technologies are introduced. It is therefore proposed that the Taskforce consult with its members and other CCS stakeholders to obtain their views on the development of a CCS communicators' forum, or similar structure, which will provide a coordination node for CCS in Australia. There is an opportunity to develop credible, verified and consistent messages; create a reference source to avoid duplication; and on occasions, and if agreed, coordinate a response to a specific event (announcement, overseas event, etc). One of the key tasks of this group would be to develop CCS messages in the context of the whole portfolio of responses to climate change, and liaise with relevant groups developing other responses.

It should be emphasised that the proposal is to consult with CCS industry stakeholders on an optimal structure, not to recommend any particular outcome at this stage. The objective is to ensure all stakeholders are aware of the resources already available, and to provide an opportunity to discuss the effectiveness of different approaches and actions, both actual and proposed.

13 KNOWLEDGE GAPS AND PRIORITY RESEARCH AND DEVELOPMENT

R&D priorities have been developed in discussions with industry. Alignment of research efforts will be required across all Australian projects and activities (CO₂CRC, ANLEC R&D, Energy Pipelines CRC), and international activities noted and involved as appropriate.

Pipelines: Research areas to be addressed prior to constructing a pipeline network for CO₂ transport include determining the state diagrams⁸² for supercritical CO₂ mixtures from different capture plants; the modelling of the transport pipeline requirements for different pipeline scenarios and CO₂ properties in Australia; examining materials compatibility with the CO₂ mixtures expected in Australia; pipeline design and full scale burst tests.

Storage Efficiency Factor: Uncertainty in the storage efficiency factor results in a very wide range of carbon storage capacity estimates for Australia of 50 to 400 years. This uncertainty outweighs geological uncertainty by an order of magnitude. For the improved planning of national infrastructure, this uncertainty needs to be reduced through research into the individual storage efficiency factors of Australia's key basins.

Migration of CO₂ in the subsurface: Further research is needed on the migration and trapping of CO₂ in the reservoir over time. It is essential for public acceptance that a deep understanding of the CO₂ movement in reservoirs is demonstrated to allow reliable risk assessment. Current models need to be improved and more detailed and sophisticated methods need to be developed.

It should be noted that most of the understanding regarding storage efficiency and migration will come from calibration of modelling using site-specific project development experience.

Freshwater Aquifers: Further research is needed to assess the possible impact of CO₂ injection on fresh water resources and how the increase in pressure from injection may influence the overall basin both at the point of injection and regionally.

Monitoring, Measurement & Verification: Cost-effective, reliable tools and technologies for CO₂ monitoring in different environments and conditions, particularly non-seismic methods, are needed. Research is needed to determine the best use of monitoring wells, especially for pressure measurement. Frameworks for environmental assessments of CCS activities are considered to be adequate⁸³, but may need to be reviewed as the knowledge base expands.

Operational issues: Some operational issues are already apparent that could be considered for R&D, such as the operability of the integrated capture, transport and storage system.

Outreach: There is clear scope for further social research on community attitudes to CCS.

⁸² Diagrams showing in what phase a substance or mixture of substances exists for any given temperature and pressure. If a substance changes phase, it may dramatically affect the operation of a pipeline.

⁸³ The Environment Protection and Heritage Committee (EPHC), in conjunction with the MCMPP, adopted Environmental Guidelines for CCS in May 2009 which acknowledge that a new legal framework is not needed and that existing environmental assessment legislation and procedures are suitable for addressing CCS.

14 NATIONAL CARBON MAPPING AND INFRASTRUCTURE PLAN

The Taskforce has developed the National Carbon Mapping and Infrastructure Plan in order to drive the prioritisation of, and access to, a national geological storage capacity to accelerate the deployment of carbon capture and storage technologies in Australia.

There are six main elements to the Plan:

1. Implement a \$254m, strategically phased, pre-competitive exploration program.
2. Release exploration acreage in the onshore Surat and Perth basins as soon as possible in addition to those offshore areas released in March 2009.
3. Develop several transport and storage demonstration projects at a significant scale of 1 Mtpa CO₂ or more, which are integrated with CO₂ capture demonstration projects.
4. Support pipeline infrastructure development that is designed to incorporate economies of scale, competitive long term costs and uncompromising safety standards.
5. Identify and recommend incentives to drive competitive CO₂ storage exploration over the period 2010–2017, in concert with other policy and fiscal settings established to support deployment of low emissions technologies, including CCS.
6. Develop and implement a Communication Strategy.

14.1 PLAN ELEMENT 1: PRE-COMPETITIVE EXPLORATION PROGRAM

The Taskforce has defined a coherent, three phase pre-competitive exploration technical work program that is required to make the decisions needed for acreage release. Outcomes of earlier phases will potentially modify specific elements of subsequent phases. The Phase 1 program costs \$84 million. Phase 2 would cost a further \$46 million, and the Phase 3 activities would cost \$124 million. The total pre-competitive exploration program of \$254 million is far in excess of the original \$50 million provided by the Commonwealth. It should be noted that this funding was proposed by the Commonwealth on the basis that both industry and state governments would also make financial and other contributions to the program.

The program, which has already commenced in some jurisdictions, is expected to be implemented over five years. Figure 42 in Section 10.2 shows the geographical and exploration scope of the program.

The objective of pre-competitive exploration is to establish that a basin is likely to have sufficient storage potential to justify release for efficient commercial exploration and development, and to ensure that enough is known about the basin to release acreage in a way that optimizes the storage potential of the basin.

In terms of storage capacity, Australian basins have been ranked as suitable to possible. The amount of available data and knowledge of these basins is variable. In basins with oil and gas production, data and knowledge of the basin's architecture and geology is generally much better, although even in these basins, the focus of the oil and gas industry is on the structural high trends and not in the deeper parts of the basin that may be attractive for CO₂ storage.

There are significant differences between CO₂ storage and oil and gas operations. CO₂ storage areas are expected to be large and the effects of pressures produced by injection of CO₂ will occur over even greater areas. CO₂ is likely to be mobile for some time during the storage process and in order to release acreage, authorities will need to have a much greater understanding of the basin's architecture than would be required for oil and gas activities. Pore space is the main asset in a basin. Authorities will need sufficient information to create basin-scale reservoir models and simulations to understand each

basin's storage capacity and to inform strategies for maximising the CO₂ storage asset. The containment of CO₂ will need to be well understood. Also, the potential impact of carbon storage operations on other resources needs to be understood (e.g. basin use for extraction of other hydrocarbons, storage of gas, fresh water, geothermal heat, coal seam methane extraction, underground coal gasification, etc).

Data quality from pre-competitive work needs to be sufficient for informed decision-making in all of these issues, with a balance between adequate knowledge and regulatory and legal requirements. There needs to be a focus on pre-competitive work at the regional scale level by governments. The 'prospect' scale is where private industry operates.

Future work includes developing a comprehensive GIS database with a standard format to ensure that ongoing work is sustainable and usable in the future. Existing geological data needs to be accessible through a national basins database that is established through the participation of the Commonwealth (Geoscience Australia), state and NT governments. Funding (~\$3 million) is recommended to develop this distributed database. A key output of this work will be national GIS coverage. GIS themes will include seismic data, well data, rock properties, and fluid properties. Such a database will have application for resources of an entire basin, from potable water at shallow depths, to oil, gas and geothermal sources at increasing depths. This holistic approach is necessary to anticipate and manage any resource conflict.

New work programs totalling around \$250 million, designed to provide pre-competitive data for both industry and resource management by jurisdictions, should either commence as soon as is possible, or be accelerated, to make Australia storage ready. The pre-competitive exploration program has been determined and prioritised by the state government geological surveys and Geoscience Australia using both the strategic and technical criteria i.e. the basin is likely to be required for storage in the near to medium term; there are strategic infrastructure decisions (e.g. pipeline decisions) that depend on the basin's storage potential; there are potential resource conflicts where pre-competitive information is required to understand better the basin's viability; and, the basin may be suitable for carbon storage but there is insufficient data and knowledge of the basin to allow an informed release of acreage. The work programs identified should be undertaken more or less concurrently, and be coordinated to achieve economies of scale: for example land seismic acquisition programs and/or onshore drilling programs.

Basins that are relatively well known and already under consideration for large scale demonstration are not considered for first rank pre-competitive exploration, unless market testing reveals that they do not attract private investment. Basins currently under release for tender were ranked lower, but may be re-evaluated once the response of the market to the tender is known.

The Phase 1 program costs \$84 million. Phase 2 would cost a further \$46 million, and the Phase 3 activities would cost \$124 million. The later phases will be modified according to the results obtained from earlier programs. The total pre-competitive exploration program of \$254 million is far in excess of the original \$50 million provided by the Commonwealth and would need to be augmented by additional funding from other sources.

The Taskforce recommends that a Review Committee be established to consider the pre-competitive exploration programs across the jurisdictions, charged with:

- optimising the expenditure on the programs by aligning them in timing and location (i.e. reducing the mobilisation costs and possibly obtaining savings through multi-project programs);
- updating the priorities of the program in light of near term results from exploration programs and tendering of areas; and
- reporting back to government (through the Ministerial Council) on the results, their implications and expenditure.

It is important that in reaching its decisions, the Review Committee continues the consultation process with CCS stakeholders, which has been a key element of the work of the Taskforce. Further work is required to determine the most suitable structure and process by which effective consultation with stakeholders, and non-government funding participants, can take place.

The Taskforce also recommends that high risk projects should be 'gated' and additional expenditure be released subject to the results from the initial exploration projects.

Geological emissions data and emissions data have been generated by the Taskforce and will be generated by the exploration program. It is very important that this data be captured in a database.

14.2 PLAN ELEMENT 2: EXPLORATION

Large-scale, commercial carbon storage capacity may be needed as early as 2020. However, the lead time to develop a large capacity, aquifer storage site from commencement of exploration to commencement of CO₂ storage at large scale has been estimated to be between ten and thirteen years. Hence exploration needs to start by 2010 if timeline targets for significant CCS deployment are to be met.

In March 2009, the Commonwealth Minister for Resources and Energy announced the release of ten offshore areas for the exploration of greenhouse gas storage areas in the Gippsland (Vic), Torquay (Vic), Otway (SA), Vlaming (WA) and Petrel (NT) basins, as shown in Figure 47.

Figure 46: Greenhouse gas assessment areas – acreage release



The capacity estimates for the Gippsland, Otway and Petrel basins and their proximity to emissions hubs make these important exploration prospects. The Gippsland Basin has the highest technical rank for storage basins and the lowest transport and storage cost of all the basins examined by the Taskforce and the commencement of exploration here is essential if the Latrobe Valley hub is to evolve successfully.

Storage capacity estimates for the Vlaming and Torquay basins suggest that they are small and more suited to pairing with single source emitters (in the order of 1–5 Mtpa).

In considering the need for exploration, the Taskforce has identified that the release of acreage is required urgently if large-scale storage capacity is to be available by 2020–25. Acreage release is required over the Surat for emissions from the Eastern Surat, and potentially from the Hunter Valley, if closer storage reservoirs are not identified. Acreage release is also required over the onshore Perth basin for the Perth / Kwinana hub.

There are several challenges facing the commencement of exploration in 2010. The first is having legislation in place to allow exploration and development to proceed. Jurisdictions covering the offshore Commonwealth waters and onshore Victoria, Queensland, and South Australia have established legislation. Regulations and guidelines to support this new legislation are under development and are expected to come into force during 2009/10. Western Australia and New South Wales are yet to put legislation in place. The Northern Territory and Tasmanian governments do not anticipate any storage requirement within their jurisdictions (onshore), and so are taking no action.

The second and bigger challenge is the incentive for explorers to take up acreage when the nature and degree of volatility in any future carbon regime is uncertain. Deployment of CCS will be accelerated by early complementary investment by industry and government, rather than reliance solely on government 'pre-competitive' programs.

At the time of writing, the CPRS is intended to start in mid-2011 (after exploration should have started) and a carbon price of \$10/tonne will apply between 1 July 2011 and 30 June 2012. From 1 July 2012, businesses covered by the scheme will need to purchase permits at the prevailing market price. Under CPRS-5, the cost of carbon is not projected to reach levels that support commercial storage operations until around 2020–2025.

This means that the explorers taking up acreage in 2010 would be risking hundreds of millions of dollars to explore for storage in a carbon regime that is not proven, nor commercially attractive. Conversely, if the explorer waits until there is confidence in the carbon regime and pricing (potentially until around 2017 or five years after the market opens), storage would not be available until 2025–2030.

It is likely that commercial exploration for carbon storage must take place over the period 2010–2017, if timeline targets for significant CCS deployment are to be met.

To this end, the Taskforce have begun to examine options that could incentivise exploration. The Petroleum Search Subsidy Act (PSSA), which was active from 1957 to 1974, has been examined to see whether a similar scheme would be suitable to promote the exploration for the deployment of carbon storage exploration. The research shows that the PSSA was effective in that it stimulated exploration activity, reduced the cost for explorers, and gave the government rights to data and samples. Any such scheme would need to look carefully at what activities are actually subsidised and how government ensures that its money is being spent on useful exploration without getting into the business of the explorers.

There are alternative options that could also assist in narrowing this financial gap. For example, immediate depreciation write off for capital investment in low emissions technology could make the upfront investment decisions in these projects more attractive.

The Taskforce considers that the release of acreage over the onshore Surat and Perth basins is a high priority if timeline targets for significant CCS deployment are to be met.

Legislation to allow exploration in onshore Western Australia, New South Wales and Northern Territory needs to be established. Consistency of exploration and storage legislation in different jurisdictions to facilitate investment should be encouraged.

The Taskforce recommends that options for carbon storage exploration incentives over the period 2010–2017 be further explored and evaluated by the Taskforce with a firm recommendation to be made to the Minister for Resources and Energy by the end of the first quarter, 2010.

14.3 PLAN ELEMENT 3: DEMONSTRATION

The volumes to be stored annually in Australia are large (~200 Mtpa) and some storage basins may need to store up to 50 Mtpa. If further demonstration of storage is to be successful, it needs to prove that the technology can be applied at a significant scale (greater than 1 Mtpa). A range of CCS projects associated with petroleum projects now exist internationally at this level, some operating for over a decade.⁸⁴ A portfolio of demonstrations is required to demonstrate different aspects of CCS technologies, and this could involve smaller scale projects according to the specific target of the demonstration project. However, the Taskforce was given a strong message from potential investors and the financial community that only demonstration at large scale will be sufficient to build the confidence and knowledge needed to invest in full scale storage.

The aversion of the investment and financial community to the first-of-a-kind risks associated with initial power-related CCS demonstration projects indicates clearly that these projects will require large amounts of public funding to proceed. It is also clear that the amount of public funding required is closely related to the perceived risks for private investment, and that governments can potentially

⁸⁴ Sleipner 1 Mtpa since 1996; Snohvit 0.7 Mtpa since 2008; In Salah 1.2 Mtpa since 2004; Weyburn Midale 1.8 Mtpa since 2004

reduce the requirement for public funding by actively striving to manage and reduce first-of-a-kind project risks.

It is also important for community acceptance that the first demonstrations of storage technology are a success i.e. that CO₂ is successfully and safely stored, and that it does not leak. The best prospect for this is in depleted oil and gas fields, where the geological trap integrity is more likely. The depleted gas and oil fields of the Surat and onshore Perth basins are potentially the most attractive candidates, although they have low storage capacity. Storage sites in existing fields have added attractiveness in that they could be developed relatively quickly (possibly by 2015–16), due to the high existing knowledge of the reservoir characteristics. Site development in these areas would, however, need to include thorough investigation of the integrity of existing wells.

Aquifers in basins with high carbon dioxide storage potential present an attractive alternative. The Taskforce considers that storage sites of ~3 Mtpa capacity could be available in the Gippsland, Surat and onshore Perth basins by around 2018. These locations have the advantage of being onshore (or close to shore) and they are proximal to potential capture demonstration sites, hence the transport and storage costs are low.

The demonstration projects need to link capture, transport and storage elements so that the risks associated with the operability of the overall integrated system at high utilisation factor and scale can be understood and mitigated. This is a significant aspect that needs to be resolved to support future successful financing of commercial projects.

The deployment of CCS technology in Australia, at large scale, will first be achieved by the Gorgon Project in northwestern Australia. The Gorgon LNG Project, which aims to store some 3.5 Mtpa of CO₂ in reservoirs under Barrow Island will be the largest storage project in the world and represents a critical step towards large-scale commercial storage of CO₂. The project was sanctioned in the fourth quarter of 2009.

Aquifer storage sites of ~3 Mtpa capacity could be available for demonstration projects by 2018. Projects that have already started an evaluation process may be able to achieve an earlier result.

Demonstration projects need to be of a significant scale (greater than 1 Mtpa) and they should link capture, transport and storage elements so that the risks associated with the operability of the overall integrated system can be understood and addressed.

The Taskforce recommends that proposals for integrated demonstration projects at a scale greater than 1 Mtpa (i.e. capture, transport and storage) in the Gippsland, Surat and Perth basins should have highest priority for funding, given the expected importance of these basins in establishing Australia's first storage sites and hubs.

Demonstration projects should be designed to develop a better understanding of storage, including storage efficiency, migration behaviour and monitoring techniques.

14.4 PLAN ELEMENT 4: INFRASTRUCTURE

Capturing economies of scale: The economies of scale offered by combining multiple sources for transport in a large size pipeline are significant and could potentially reduce deployment costs for CCS substantially. However, investing today in an 'oversized' pipeline involves significant risk, as the asset may ultimately be underutilised, or worse, stranded, during its working life. The Taskforce therefore recommends provision of support for 'oversizing' of pipelines, following careful analysis of likely future loads. This analysis needs to be conducted at a 'hub' level, which considers all likely sources of demand for transport. There is a range of infrastructure support models already in place. The mechanism

would need to be considered on a case by case basis. Government support has been common in the development of Australian pipeline infrastructure.⁸⁵

Retaining easement options: Successful deployment of CCS in demonstration hubs will enable investors and governments to consider substantial capital investments in long distance 'backbone' pipelines. If more local storage is unable to be identified, these pipelines could link a range of emissions sources to distant storage reservoirs. Delaying a decision on construction of large scale pipelines will also provide more certainty in relation to competitive technologies and the operation of the carbon pricing regime, which drive the projected location and quantity of emissions requiring transport. In the interim, it is vital that the easements or pipeline routes that could be used in the future are not compromised by uninformed planning and development. The Taskforce therefore recommends that governments consider in detail potential pipeline routes and easements for future CO₂ pipelines, and incorporate these routes into their planning and approval processes. This will require integration across several levels of government, and liaison with the Australian Energy Markets Operator (AEMO).

Building confidence: Australian communities need to be confident that CO₂ pipelines will be safely managed. This confidence is built at several levels, including development of: i) an accurate and reasoned understanding of the risks and how they can be managed, ii) confidence in the capacity of regulators, and iii) confidence that industry standards provide suitable risk management requirements. These elements will need to be developed in an Australian setting, drawing on the substantial experience and knowledge developed globally and through existing Australian practice.

The Taskforce recommends that a report detailing Australian legislation, regulations and codes affecting deployment of CO₂ pipelines be commissioned by the Taskforce for completion by the end of the first quarter, 2010. This report will also seek to identify any actions required to ensure regulatory management systems relating to deployment of CO₂ pipelines are in place in time to match the requirements of project proponents. This report will complement the report commissioned by the Australian Pipeline Industry Association (APIA) Research and Standards Committee⁸⁶ providing a gap analysis for the AS2885. The Taskforce recommends that these reports then be considered by the relevant regulators from each jurisdiction, and that a work program of actions and milestones for outcomes be confirmed by the end of the second quarter, 2010. The MCMPR CCS Working Group⁸⁷ is likely to be a suitable vehicle for this coordinated action by governments.

14.5 PLAN ELEMENT 5: POLICY AND FISCAL SETTINGS

The Taskforce considered the nature of any market failure and the level and nature of any required government intervention to address such matters.

Market Drivers

Carbon dioxide capture, transport and geological storage adds a cost to operations currently venting the carbon dioxide into the atmosphere. The activity does not generate a revenue stream, but instead imposes very substantial costs and potential liabilities.⁸⁸ The only current commercial incentive to deploy CCS is the perception that it will form part of a company's social licence to operate. That is, that development approval, or a continuing licence to operate, may not in future be granted for plants emitting CO₂ without (or even with) some form of offsetting activity. Many companies seek to operate in a manner that minimises their environmental impact, but the scale of investment required for CCS is

85 Kimber M.J. 2009, *Development of Australia's Natural Gas Resources: A Possible Model for Carbon Capture Transportation and Storage*, report prepared for the Carbon Storage Taskforce, Department of Resources, Energy and Tourism, Canberra.

86 APIA Research and Standards Committee, 2009, *Gap Analysis for Use of AS2885 for CO₂ Pipelines*, Research Project APIA 08-09 report prepared by Venton and Associates, Peter Tuft and Associates.

87 The MCMPR CCS Working Group provides a forum for discussions between jurisdictions within Australia on CCS policy, in order to support consistency in regulatory frameworks.

88 In Australia, it appears likely that there will be only limited opportunity to use captured CO₂ to enhance oil recovery and so generate revenue. There are some processes that utilise CO₂ to generate other products, but these do not typically contribute ultimately to the avoidance of emissions.

typically too great for individual companies to make unilaterally. This is particularly the case for electricity generators, which operate on tight marginal returns in a highly competitive market.

Current Policy Status

The Australian Government recognises the potential future cost of the impacts of climate change, and the scale and timelines of the required response. The most significant current policy setting is the introduction of a system that creates a price for emissions and simultaneously enables trading of emissions exposures, using emission permits. The intent of the CPRS is to create a market mechanism that leads to the deployment of the lowest cost mechanisms for reducing emissions. Other important policy settings include the continuing imposition of a mandatory technology target for renewable energies (MRET), which spreads the resulting increased costs of energy generation across the NEM, and capital grants for developing 'first of a kind' low emissions technologies under the Clean Energy Initiative, announced in the 2009 budget. This includes allocation of capital grants for demonstration 'flagship' projects, including CCS operations. The Government has also created and funded the GCCSI which is mandated to facilitate the G8 development goal of 20 'commercial scale' CCS flagship projects internationally by 2020.

Investment Appetite

Investors seek certainty regarding the factors that put their investment at risk, and the mechanisms for risk mitigation or avoidance. CCS projects at commercial scale will require commitments of many billions of dollars to plants expected to generate profitable returns for 30 to 40+ years. Currently, these investments face two primary and interrelated risks – an unknown future carbon regime and cost, and technological obsolescence. In this environment, there is little, if any, incentive for most companies to individually allocate a significant proportion of their capital to developing CCS projects today.

Nevertheless, investment can still take place when risks are high, if the return is considered adequate. This is clearly the case for CCS, where deployment of this technology could contribute significantly to reduction of global emissions, while continuing to use coal and gas to generate energy without generating significant emissions. The potential industry size is huge, and thus presents an attractive target for companies supplying goods and services to the industry. These factors drive the composition of the current investor group, which comprises governments, very large corporations, fossil fuel industry groups, generator equipment suppliers, and oil and gas operators and service providers.

14.5.1 Accelerating Australian Deployment of CCS

Given these current policy settings, and the investment climate, the following actions are recommended:

Create a consistent 'carbon regime': 'Carbon regime' refers to the portfolio of policy instruments that seek to modify behaviour in relation to carbon dioxide emissions. The key driver for lowest cost price discovery will be the CPRS, but its impact will be modified if other instruments are retained or introduced, such as mandated technology targets (e.g. MRET), or emissions controls specified in licensing processes. Investors are seeking certainty regarding the total regime, not just one element of it. It is important to also note that it is the perception of what the carbon regime will be over the next two to three decades that affects investment decisions, not just the carbon regime anticipated in the near term.

Fund demonstrations: Fund and identify opportunities to mitigate risk of 'first of a kind' demonstrations that are at commercial scale and that integrate capture, transport and storage. This is a very effective use of government funds as it builds confidence with community stakeholders and investors in the technology and operability of CCS, which potentially leads to commercial deployment.

Select lowest cost, large scale hubs first: Direct support to hubs that appear likely to yield lowest cost outcomes for long term, large scale deployment of CCS. This gives the hub the highest chance of surviving any future competition and so reduces investment risk. This approach is more likely to accelerate larger scale deployment of CCS, as it concentrates limited resources to a solution that supports a larger outcome. The form of support requires more detailed investigation. Provision of capital grants and the introduction of the CPRS will be the key drivers.

Seek economies of scale: Support hub design that accommodates expected future load. For example, a government could act as a 'foundation customer' to underwrite large diameter pipeline investments with a 'take or pay' contract (as governments have done for gas pipelines).

Build on success: Successful demonstration of lower cost hubs will build confidence to make large scale investments such as long distance 'backbone' pipelines to link distant emissions hubs. Investment in these pipelines prior to demonstration using lower cost alternatives is not recommended at this stage.

Place highest priority on developing storage reservoirs: The CCS industry recognises that without confidence that a suitable storage reservoir can be utilised, investment in capture or transport facilities is of limited or no purpose. It is also recognised that developing adequate levels of confidence in a storage formation is likely to consume the largest amount of time in typical CCS project development. **Exploration programs must therefore commence immediately to meet the Government's deployment timeline targets.** Despite this imperative, there is little, if any, commercial incentive today to invest the substantial capital required. In the absence of a strong market signal, governments therefore have a key role in accelerating exploration activity. This may take two forms:

1. Increase funding for acquisition of 'pre-competitive'⁸⁹ data. The Taskforce has identified a prioritised program that supports a portfolio development approach in Australia. Importantly, this program is 'gated', that is, the program of activities proposed in the initial program will be confirmed, amended, or cancelled according to the interpretation of the results of earlier activities as they are received.
2. Stimulate and accelerate exploration activity by private operators. This action needs to be put in place from around 2012 to around 2017, by which time investors should start to have confidence in the carbon market and future prices. There are a number of mechanisms that could be used to achieve this outcome.⁹⁰ The Taskforce recommends that the specific mechanisms for supporting private sector exploration be examined in more detail.

14.6 PLAN ELEMENT 6: COMMUNICATION

Deployment of CCS in Australia relies on community acceptance. It is important that information on CCS is presented in an open and transparent manner through trusted channels. It is equally important that communications on alternative responses to climate change and low emissions energy sources provide similarly full information on what each response can deliver, the risks and likelihood of successful deployment and what it will cost. Any CCS communications activity needs to be delivered in this context.

The CCS industry comprises a disparate group of stakeholders. To date, communications have been on a mostly independent, ad hoc basis. This may remain the most appropriate model, but there may also be an opportunity to avoid delivery of conflicting or erroneous information, and to avoid duplication of effort. A highly centralised coordinating body directing a single message is not recommended, as it is unlikely to satisfy the requirements of every stakeholder.

The Taskforce proposes instead that CCS industry stakeholders are consulted for their views on the most effective structure to enhance communications for CCS deployment in Australia. Consideration could be given to a network, such as a CCS Communicators' Forum, but no particular structure is being recommended prior to wider consultation. The Taskforce would deliver the outcomes of this consultation to its members and stakeholders prior to year end 2009, with the intention that a recommended structure and management plan be put in place in the first quarter of 2010.

A need for assurance that CCS deployment will be safe and secure is the community concern most often heard. Pipeline transport and storage are the activities to which most people will be exposed. As noted

⁸⁹ Data acquired for public dissemination, issued to encourage bidding by exploration companies for land over which they will be granted an exclusive exploration right.

⁹⁰ For example, the *Petroleum Search Subsidy Act 1959* enabled subsidies for exploration well costs until 1973, by which time the private sector had strong interest in Australia as an exploration target. The drilling cores obtained from this program form the basis of Geoscience Australia's geological database for Australia.

in the infrastructure discussion, the Taskforce recommends that a program of research and development activities be defined and implemented which will provide further assurance to regulators and the community that infrastructure and storage can be managed to produce safe outcomes in Australia.

14.7 PLAN IMPLEMENTATION

Work programs supporting each recommendation will be further developed by the Taskforce to be presented to the Minister for Resources and Energy by the end of 2009. These identify the tasks required for each activity, and the resources and timelines necessary to achieve suitable outcomes.

When the Australian Government established the Carbon Storage Taskforce, it was envisaged that the Taskforce would spend six months developing the National Carbon Mapping and Infrastructure Plan and then a further six months overseeing the initial implementation of the Plan. Responsibility for oversight of the Plan beyond initial implementation was not addressed.

The Plan and the Taskforce's other recommendations cover a wide range of activities and subject areas over the next ten years to 2020. If Australia is to maintain CCS as a carbon pollution reduction option, then the Taskforce considers it is important that clear accountability is established for the strategic oversight and coordination of the implementation of the Plan and Taskforce recommendations. Successful implementation will require coordinated, focussed programs, with the priorities set from a national perspective to achieve maximum effectiveness. Deployment of CCS in Australia at a meaningful level will entail the development of a major new Australian industrial activity, of a size similar to that of the existing petroleum industry. A CCS Council, or some similar entity, could be used to support and accelerate this level of deployment.

The composition of the CCS Council should represent the diverse range of stakeholders in the CCS area including industry (power generators, coal producers, oil and gas producers, pipeline industry, cement, alumina, aluminium, steel/iron manufacturers and petroleum refiners), government (federal and state), eNGOs and employee representatives. A reporting relationship with the MCMPPR through the Minister for Resources and Energy would assist with national coordination and prioritisation.

The Council would only exist for as long as is needed to ensure the successful implementation of the Plan.

Australia is one of the nations likely to be affected by climate change earliest and hardest. Delaying action to mitigate greenhouse gas emissions is considered likely to result in substantially greater costs, and impacts. The technology identified as having the greatest potential to mitigate greenhouse gas emissions from large-scale fossil fuel usage is carbon dioxide capture and geological storage.

The Taskforce has assessed that the deployment of CO₂ transport and storage in Australia is technically viable and could be safely implemented. However, CCS-related activities must be accelerated and maintained over the next decade if the nation is to be in a position to capture the opportunity for commercial deployment beyond 2020. While there are many challenges to be overcome, the Taskforce believes that, through the implementation of the Plan and the Taskforce's recommendations, they are manageable.

15 ACKNOWLEDGEMENTS

Geoscience Australia, and in particular the CCS Storage Section, took the lead in drawing together disparate information to facilitate the assessment of basin and oil field storage potential and capacity.

The Geosequestration Mapping Taskforce (the Chief Geoscientists and their representatives from the national and state geological surveys) played a pivotal role in ranking Australia's basins storage potential and in creating the pre-exploration component of the National Carbon Mapping and Infrastructure Plan. They maintained a national perspective throughout the process.

A strong feature of the Taskforce's report is the depth of understanding of pipeline issues. This work was very ably led by the Australian Pipeline Industry Association (APIA) with input from many of its members. APIA also facilitated a meeting with Dr Julia Race, an internationally recognised expert on pipelines for CO₂ transport.

CO2Tech, the commercial arm of CO2CRC, estimated carbon dioxide storage tariffs. Economics relies on inputs from many others and, as a consequence, the work is often under schedule pressure. Dr Guy Allinson and Dr Peter Neal with their team at the University of New South Wales absorbed this pressure and were very comprehensive in their analysis of tariffs.

The Queensland Government and CSIRO conducted a thorough review of the potential impact of carbon storage operations on the Great Artesian Basin.

CSIRO is acknowledged for allowing Peta Ashworth to help the Taskforce to understand potential community concerns and possible responses about carbon storage and transport issues.

There was close cooperation and communication with the National Low Emissions Coal Council, and its Strategy Working Group, and comments from Council members enhanced the report considerably.

The Taskforce published a concise version of this report previously. Dr John Burgess drafted and adapted much of the more comprehensive and technically specific material contained in this detailed report.

Finally, but by no means least, the Taskforce wishes to acknowledge the excellent support provided by the Taskforce Secretariat.

16 APPENDICES

Appendix A: Terms of Reference of the Carbon Storage Taskforce

Appendix B: Summary of Communication Activities

Appendix C: Consultation by the Taskforce

Appendix D: Glossary of Terms

Appendix E: Montage of the Gippsland Basin

Appendix F: Bachu Ranking Criteria for Sedimentary Basins for CO₂ Storage

Appendix G: Methodology for Basin Storage Capacity Used in this Study

Appendix H: Methodology for Determining People and Other Resource Requirements for the Appraisal and Development Phases of CCS Development

APPENDIX A: TERMS OF REFERENCE

CARBON STORAGE TASKFORCE

Introduction

The Carbon Storage Taskforce will bring together key stakeholders to develop a National Carbon Mapping and Infrastructure Plan ('the Plan'). The primary aim of the Plan is to develop a road map to drive prioritisation of, and access to, a national geological storage capacity to accelerate the deployment of carbon capture and storage (CCS) technologies in Australia.

Membership

Membership of the Taskforce will include all key industry sectors with an interest and expertise in carbon storage including coal, power generation, oil and gas, pipeline operators, geological survey agencies, unions and non-government organisations as well as representatives from the Commonwealth and state governments.

Key Tasks

The Taskforce will develop a National Carbon Mapping and Infrastructure Plan which will provide a roadmap for geological storage to support significant penetration of CCS technologies into the Australian electricity, oil and gas, and industrial sectors. Specifically, the Taskforce will:

- examine existing ongoing work across jurisdictions on identifying potential carbon storage sites and their proximity to carbon sources;
- identify a priority list of potential storage sites taking into account major sources of CO₂;
- identify broad infrastructure requirements to facilitate CO₂ storage based on current knowledge of source/sink matches;
- identify gaps in existing knowledge in the areas outlined above and any priority areas for future work and/or research;
- identify main priorities for industry;
- identify the potential for the market to develop an adequate national carbon storage and infrastructure capacity, the nature of any market failure and the level and nature of any required government intervention to address such matters;
- examine potential community concerns about carbon storage issues, and make recommendations on potential approaches for addressing them; and
- make recommendations on a forward work program to address issues arising from consideration of the above issues.

Following consideration by the Australian Government and the approval of a forward work program, the Taskforce will oversee the initial implementation arrangements for the Plan which will draw on a coordinated approach between geological survey agencies from the Commonwealth and the States.

Timing

The intention is for the Taskforce to operate for 12 months, with the final Plan being submitted to the Commonwealth Minister for Resources and Energy within six months. Following endorsement of the Plan by the Government, the Taskforce will oversee initial implementation arrangements, including in relation to the approved forward work program.

Working Arrangements

The Taskforce will determine its own operating arrangements, including the need to establish specialised working groups to examine issues of specific interest for the development of the Plan.

These could include for example, geological storage and monitoring; pipelines and infrastructure; and health and safety, and community issues.

The Taskforce will also work closely with the National Low Emissions Coal Council ('the Council') including providing regular progress reports of its work and seeking and taking into account any comments that the Council may have on its work. Specifically the Taskforce will provide the Council with an opportunity to comment on its plan before it is finalised and submitted to the Minister for Resources and Energy.

APPENDIX B: SUMMARY OF COMMUNICATION ACTIVITIES⁹¹

STAKEHOLDER GROUP		NOTE	SUGGESTED ACTIVITY	FREQUENCY (PER YEAR)
INFLUENTIAL OTHERS				
Policy Makers	Federal; State	Includes environmental, health, minerals, energy, science, technology and innovation portfolios.	Presentations to Government Departments – understanding by key government figures is integral to the success of the project and this group will need to be proactively targeted.	4
Politicians	Federal; State	Should be extended to all parties.	Workshops for politicians and their researchers – Politicians have expressed an appetite for information on the topic of climate change and energy technologies. Need to run short sharp workshops to allow them time to ask questions and understand the complexity of the carbon issue.	2
Financial, Insurance, Legal	International; National		Personal Invitations CEO Breakfast Meetings – host a series of breakfast meetings to target key stakeholders in this group. Small groups will allow for more interactive discussion and dialogue.	4
			Individual presentations to stakeholder group – similar to government these groups will require specific information around which to base their decisions.	4
			Keynote speaker roles at international conferences – interest in the development of these technologies is global and therefore investment should not be limited to Australian waters.	Ad hoc
Media	National; State; Local		Workshops for journalists across Australia – proactive communication with this group is essential to ward against opportunities for misinformation. Small groups will be more effective and offers to transport them to the project site while it is being developed will be essential.	4

⁹¹ Adapted from Ashworth, P. (2008) *Social and Economic Integration: Managing Stakeholder Dialogue for Low Emission Coal Gasification*. Presentation for Centre for Low Emission Technology, Brisbane, Qld, 8th April, 2008

STAKEHOLDER GROUP		NOTE	SUGGESTED ACTIVITY	FREQUENCY (PER YEAR)
Environmental NGO's	International; National; State; Local	New Zealand and nearby Asian countries should be considered in this approach.	Workshops for ENGO's across Australia – proactive communication with this group is essential to ward against opportunities for misinformation. Need to develop energy champions.	1
			Engage NGO representative – research has shown that engaging an NGO group will help to build trust in the project. Funds should be allocated to buy this person's time as a representative from a not for profit organisation.	4
			Individual presentations to representatives – it will be important to ascertain individual representative's views on the project to elicit concerns and their respective positions about the project.	4
Other Industry Peak Bodies	National		Personal Invitations CEO Breakfast Meetings – host a series of breakfast meetings in various states to raise awareness of the project and possibly identify alternative funding opportunities. Up to 20 people should be invited, more intimate setting allows for more interactive discussion and dialogue.	2
EDUCATION				
Materials Development	International; National	Global community is beginning. Coordination is the key.	Coordinated approach to the development of education and information materials for society.	Ongoing
Media Press Packs	National		Media packs – although media will be engaged as influential others, materials to support any media releases will be required.	Ongoing
Curriculum Development	International; National	Coordination with other groups working in this area will minimise duplication.	Coordination of classroom materials to enable easy delivery for teachers.	Ongoing
Science Week	State			7
Local Education Initiatives	State; Local		Time and travel.	7
School Talks	State; Local		Time and travel.	7

STAKEHOLDER GROUP		NOTE	SUGGESTED ACTIVITY	FREQUENCY (PER YEAR)
GENERAL PUBLIC				
EnergyMark (CSIRO's community education and awareness program)	National	Should buy a seat on the steering committee to be key recipient of information and feedback.	Engages community groups around the topic of climate change and energy technologies.	4
Local community conferences	National; State; Local	Community groups such as CWA, ICLEI, LGA	Presentations on request.	Ad hoc
PROJECT SPECIFIC				
Local government	Local		Workshops for local councils in the area – this group are key to project success at the local level and require ongoing dialogue activities at project inception through to deployment.	4
Landholders			Individual meetings as required. Time and travel.	Ad hoc
Local community groups	Health; Infrastr.; Nat. Resources; Local NGO's		Workshops for local stakeholder groups – these groups have the influential roles within the local community and acceptance of the project at this level is crucial for deployment. May not always be the same groups of individuals.	4
General Public	Local		Public meetings – Open discussion forums allow local community representatives to have their say if they are not accessed through formal dialogue channels. Important at the beginning of the project, community liaison group can take up the role going forward once issues have been overcome.	2
Schools	Local		Target local schools – Provision of materials, talks, site visits.	Ad hoc
Community Liaison group			Meetings every six weeks or as required – minimal cost because it is local volunteers.	7
Community Liaison Person			Part-time person – on the ground near demonstration project site.	Ongoing
OTHER CONSIDERATIONS				
Website				
Communications Person				

APPENDIX C: CONSULTATION BY THE TASKFORCE

The Taskforce sought to consult widely in acquiring information and forming its recommendations. Listed below are the various individuals, organisations and companies that contributed to various aspects of the Taskforce's activities.

Carbon Storage Taskforce

Chair

Australian Coal Association
Australian Petroleum Production and Exploration Association
Australian Pipeline Industry Association
Australian Pipeline Industry Association
Construction, Forestry, Mining, Energy Union
Cooperative Research Centre for Greenhouse Gas Technologies
Department of Employment, Economic Development and Innovation, Queensland
Department of Primary Industries, N.S.W.
Department of Primary Industries, Victoria
Department of Primary Industries and Resources, S.A.
Department of Resources, Energy and Tourism (RET)
Geoscience Australia
National Generators Forum
National Generators Forum
National Geosequestration Mapping Working Group
WWF-Australia

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Bill Koppe
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Observers

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Australian Petroleum Production and Exploration Association
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Department of Primary Industries, Victoria
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 Department of Mines and Petroleum, W.A.
 Department of Primary Industries, N.S.W.
 Department of Primary Industries and Resources, S.A.
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MCMPR CCS Working Group

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 Department of Environment, Water, Heritage and the Arts
 Department of Mines and Petroleum, W.A.
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 Department of Primary Industries, N.S.W.
 Department of Primary Industries, N.S.W.
 Department of Primary Industries, Victoria
 Department of Primary Industries, Victoria
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 Matt Johnson
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 Grant Arnold
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WORKSHOPS

Mapping Workshop – 16 March 2009

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 Meredith Dinneen
 John Draper

 Jeff Haworth
 Robert Larkings
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 Kathy Hill
 Geoff O'Brien
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Project Finance Workshop – 14 May 2009

Access Economics
 Anglo Coal
 ANZ Bank
 Australian Coal Association
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Clinton Foundation
CS Energy
CSIRO
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Queensland
Department of Employment, Economic Development and Innovation,
Queensland
Department of Primary Industries, N.S.W.
Department of Primary Industries, Victoria
International Power
Macquarie Capital Advisers
Monash Energy
National Low Emissions Coal Council
Niche Tasks
PriceWaterhouseCoopers
PriceWaterhouseCoopers
Santos
Schlumberger Carbon Services
UBS
Westpac Institutional Bank
Worley Parsons
ZeroGen

Peter Wilson
Larissa Cassidy
Meredith Dinneen
John Torkington
Tony Wood
John Harten
Peta Ashworth
Stuart Booker

Rob Metcalfe

Brad Mullard
Fiona Clarke
Chris Kendall
Sally Aitken
Scott Hargreaves
Bruce Godfrey
John Burgess
Brian Johnson
Simon Parbery
Mike Congreve
Andrew Garnett
Angela Karl
Nick Cleary
Peter Brooks
Chris Greig

Scenarios Workshop – 15 May 2009

Access Economics
Australian Coal Association
Australian Coal Association
AngloCoal
Australian Pipeline Industry Association
Carbon Storage Taskforce
Carbon Storage Taskforce (Chair)
Carbon Storage Taskforce Secretariat, RET
Carbon Storage Taskforce Secretariat, RET
Chevron Australia
Clinton Foundation
Greenhouse Gas Storage Solutions
Construction, Forestry, Mining, Energy Union
Cooperative Research Centre for Greenhouse Gas Technologies
Cooperative Research Centre for Greenhouse Gas Technologies
Cooperative Research Centre for Greenhouse Gas Technologies
Cooperative Research Centre for Greenhouse Gas Technologies
CSIRO
Department of Employment, Economic Development and Innovation,
Queensland
Department of Employment, Economic Development and Innovation,
Queensland
Department of Primary Industries, N.S.W.
Department of Primary Industries, N.S.W.
Department of Primary Industries and Resources, S.A.
Department of Primary Industries, Victoria
Exxon Mobil

Cameron O'Neill
Burt Beasley
Thomas Berly
Bill Koppe
Steve Davies
Andy Rigg
Keith Spence
Peter Wilson
Larissa Cassidy
John Torkington
Tony Wood
John Bradshaw
Tony Maher
Guy Allinson
Peter Cook
Barry Hooper
Peter Neal
Peta Ashworth
John Draper

Rob Metcalfe

Rick Fowler
Brad Mullard
Barry Goldstein
Fiona Clarke
Bob Griffith

Geoscience Australia
Geoscience Australia
Hydrogen Energy
International Power
National Low Emissions Coal Council
Niche Tasks
Santos
Schlumberger Carbon Services
Worley Parsons
WWF-Australia
Xstrata
ZeroGen
ZeroGen

Rick Causebrook
Rob Langford
Lewis Jeffery
Patrick Gibbons
Bruce Godfrey
John Burgess
Mike Congreve
Andrew Garnett
Peter Brooks
Greg Bourne
Barry Isherwood
Rod Brown
Howard Morrison

Pipelines Workshop – 5 June 2009

Australian Coal Association
Australian Pipeline Industry Association
Carbon Storage Taskforce (Chair)
Carbon Storage Taskforce Secretariat, RET
Carbon Storage Taskforce Secretariat, RET
Cooperative Research Centre for Greenhouse Gas Technologies
Cooperative Research Centre for Greenhouse Gas Technologies
Cooperative Research Centre for Greenhouse Gas Technologies
Department of Primary Industries and Resources, S.A.
Department of Resources, Energy and Tourism
M. J. Kimber Consultants
Niche Tasks
University of Newcastle, U.K.
Worley Parsons

Thomas Berly
Steve Davies
Keith Spence
Peter Wilson
Jenessa Rabone
Guy Allinson
Peter Neal
Denis Van Puyvelde
Belinda Hayter
Lindsay Gamble
Max Kimber
John Burgess
Julia Race
Peter Cox

Environmental NGO Workshop

Six environmental NGO representatives participated in this workshop. To facilitate open dialogue, this workshop was conducted on an anonymous basis.

Technical assistance:

Greenhouse Gas Storage Solutions
Cooperative Research Centre for Greenhouse Gas Technologies

John Bradshaw
Barry Hooper

GROUPS PROVIDING SERVICES

Geoscience Australia	Rick Causebrook, Rob Langford, Michelle Spooner, Chris Consoli, Chris Southby, Kane Rawsthorn, Duy Nguyen, Chris Lawson, Steve le Poidevin, Richard Dunsmore, Andrew Barret	Preparation of montages, ranking of basins, and substantial support on a range of matters for the Taskforce.
APIA Research and Standards Committee		Research project: APIA08-09 Gap analysis for use of AS2885 for CO ₂ pipelines – Mar 2009
Geoscience Australia – Petroleum and Greenhouse Gas Advice Group		Advice on Australian carbon dioxide storage potential in oil and gas reservoirs – May 2009
Queensland Government and CSIRO	Jonathan Hodgkinson, Micaela Preda, Mike McKillop, Owen Dixon and Linda Foster (Queensland Government) and Allison Hortle (CSIRO)	The Potential Impact of Carbon Dioxide Injection on Freshwater Aquifers: The Surat and Eromanga Basins in Queensland
Other	Andy Rigg, ACA Low Emissions Technologies Ltd Andrew Garnett, Schlumberger Carbon Services John Torkington, Chevron Australia	Provided comments on work relating to exploration and project development.

Commissioned Work

ACIL Tasman	Paul Hyslop, Owen Kelp	Australian stationary energy emissions: an assessment of stationary energy emissions by location suitable for capture and storage – Feb 2009
ACIL Tasman	Paul Hyslop, Owen Kelp, Martin Pavelka	Carbon Capture and Storage Projections to 2050 – Jun 2009
CO2CRC Technologies	Dr Guy Allinson, Dr Peter Neal, Felix Booth, Yildiray Cinar, Val Pinczewski	The Costs of CO ₂ Storage in Australia – Dec 2008
CO2CRC Technologies	Dr Guy Allinson, Dr Peter Neal, Wanwan Hou, Yildiray Cinar	The Costs of CO ₂ Storage in Australia – 2009
CSIRO	Peta Ashworth, George Quezada	Who's Talking CCS? Media Analysis – May 2009
CSIRO	Peta Ashworth, Richard Parsons	Australian ENGO views on CCS – May 2009
CSIRO	Peta Ashworth	A strategic approach for communication and outreach activities for CCS
M.J.Kimber Consultants	Max Kimber	Development of Australia's natural gas resources: a possible model for carbon capture, transportation and storage – May 2009
Niche Tasks	John Burgess	Drafting the Taskforce's detailed report
RISC	Graham Jeffery, Dogan Seyyar	CO ₂ injection well cost estimation – Mar 2009
RISC	Graham Jeffery, Dogan Seyyar, Stuart Weston	Gippsland Basin – availability projections for carbon storage – May 2009
Worley Parsons	Peter Cox	Carbon dioxide specification study – Jun 2009

GROUPS PROVIDING SERVICES

Worley Parsons	Peter Cox	CO ₂ injection and pumping study – Jun 2009
Worley Parsons	Peter Cox	Summary of pipeline sizing study – Apr 2009
Worley Parsons	Peter Cox	CO ₂ small diameter pipelines: total installed cost budget estimates – 2009
Worley Parsons	Peter Cox	Impacts of Interruptions to Supply for Carbon Dioxide Pipeline Transport Flow – 2009
Worley Parsons	Peter Cox	Compression Configuration Study – 2009
Deloitte Touche Tohmatsu	Rod Marsh, Govert Mellink, David Charles	Project Finance Workshop and Report
Sinclair Knight Merz	Jane Lawson	Schematic pipeline diagram
KPMG	Jennifer Westacott, Jack Holden	Scenarios Workshop and Outcomes

APPENDIX D: GLOSSARY OF TERMS

acid buffer	A chemical system that resists a change in pH.
ACIL Tasman	ACIL Tasman Ltd., a consulting company.
acreage	An area that is released for competitive exploration.
ANLECR&D	Australian National Low Emissions Coal – Research and Development Ltd.
APIA	Australian Pipeline Industry Association.
aquifer	A body of rock saturated with water that is capable of allowing the subsurface water to be stored or transmitted and is capable of absorbing recharge water.
aquitard	A body of rock that is not capable of allowing the subsurface water to be stored or transmitted and is not capable of absorbing recharge water.
AS2885	The overarching Standard that applies to the pipeline industry in Australia. This series of standards specify requirements for the design, construction, testing, operation and maintenance of pipelines.
basin	A geological depression filled with sediments.
black coal	Bituminous, anthracite and sub-bituminous coal of higher carbon and energy content and lower moisture content than brown coal. Used generally for power generation in States other than Victoria.
brown coal	Lignitic coal with lower energy and high moisture content than black coal. Used for power generation in Victoria.
carbon capture	Removal of carbon dioxide from a gas stream using chemical engineering methods.
carbon price	Price of CO ₂ e under the CPRS (\$/t CO ₂ e)
CCS	Carbon Capture and Storage.
CO ₂	Carbon dioxide, a colourless gas at ambient conditions. Heavier than air. Can be converted to a supercritical fluid at high pressures (>74 atmospheres at ambient conditions) and temperatures greater than 31oC. Product of the combustion of carbon.
CO ₂ -e	A standard measure that takes account of the different global warming potential of different greenhouse gases and expresses the cumulative effect in a common unit.
CO	Carbon monoxide, a colourless gas at ambient conditions; toxic at low concentrations in gas mixtures. Product of the partial combustion of carbon.
CO2CRC	The Australian Cooperative Research Centre focused on CO ₂ capture and storage.
coal	Combustible black or brownish organic-rich rock; a fossil fuel.
coal gasification	The process of transforming coal into fuel through the reaction of coal, water and heat.
completions engineer	An engineer trained to finish a well, which is either sealed off or prepared for production.
core	A cylindrical sample of a geologic formation, usually reservoir rock, taken during drilling a well.
CPRS	Carbon Pollution Reduction Scheme.

CPRS –5	One scenario for future carbon reduction under the CPRS.
E	Storage efficiency of CO ₂ in sedimentary rock; expressed as a percentage of the pore volume eventually occupied by CO ₂ .
ENGO	Environmental Non-Government Organisation.
EOR	Enhanced Oil Recovery. A technique whereby the efficiency of oil extraction is improved through the injection of CO ₂ and water into the reservoir.
facies	A body of sedimentary rock distinguished from others by its lithology, geometry, sedimentary structures, proximity to other types of sedimentary rock, and fossil content, and recognized as characteristic of a particular depositional environment.
FEED	Front End Engineering Design
FID	Final Investment Decision
GCCSI	Global Carbon Capture and Storage Institute.
geochemistry	The study of the chemistry of the Earth, including the distribution, circulation and abundance of elements (and their ions and isotopes), molecules, minerals, rocks and fluids.
geothermal energy	Energy obtained from beneath the earth, either from dry hot rocks with water injection to create steam, or from steam brought to the surface from hydrothermal areas.
geochemist	A scientist trained in the study of the chemistry of the Earth, including the distribution, circulation and abundance of elements (and their ions and isotopes), molecules, minerals, rocks and fluids.
geomechanics	The study of structural geology and the knowledge of the response of natural materials to deformation or changes due to the application of stress or strain energy.
geoscientist; geoscience	A scientist trained in the study of the Earth; the study of the Earth and Earth systems.
Geoscience Australia	A prescribed agency within the Australian Government Resources, Energy and Tourism portfolio; the Minister is the Hon Martin Ferguson AM MP.
GIS	Geographic Information System.
greenfield construction	Creating a new plant where no existing plant exists. 'Brownfield' refers to adaptation or expansion of the capacity of existing plant.
greenhouse gas	A gas with global warming properties due to infra-red radiation absorption. Generally refers to CO ₂ for CCS.
groundwater	Water in the subsurface below the water table. Groundwater is held in the pores of rocks.
Gt	Gigatonnes (1000 million tonnes)
GW	Gigawatts; a measure of power being generated at a given point in time. 1 GW equals 1000 MW.
GWh	Gigawatt hours; a measure of energy. 1 GWh of power being produced for 1 hour equals 1 GWh; 1 GWh is equivalent to 1000 MWh.
hub	A concentration of CO ₂ emitters in a geographic region.
hydrochemistry	The study of chemical processes and conditions in groundwater.
hydrodynamics	The study of flow of liquids and forces which influence this movement.

IEA	International Energy Agency.
injectivity	Ability to be injected; high injectivity implies high permeability of the reservoir rock strata, and low differential pressure for a given injection rate.
LNG	Liquefied Natural Gas.
MCMPR	Ministerial Council on Mineral and Petroleum Resources.
mD	milli-Darcy, a measure of reservoir permeability.
metocean	the physical environment near an offshore oil and gas facility (from 'meteorology' and 'ocean').
Monte Carlo simulation	A statistical risk analysis technique to estimate the most probable outcomes of a model.
Mt	millions of tonnes.
Mtpa	millions of tonnes per year (annum).
MW	Megawatts; a measure of power being generated at a given point in time.
MWh	Megawatt hours; a measure of energy. 1 MW of power being produced for 1 hour equals 1 MWh.
natural gas	A combustible colourless gas at ambient conditions, mainly comprising methane (CH ₄); a fossil fuel. May be liquefied at low temperatures to form LNG.
NEM; NEMMCO	National Electricity Market.
NGO	Non-Government Organisation.
NLECC	National Low Emissions Coal Council.
OECD	Organisation for Economic Cooperation and Development.
oil	A combustible liquid comprising a mixture of hydrocarbons; a fossil fuel.
petroleum engineer	An engineer trained in various aspects in the production of hydrocarbons.
Plume; (CO ₂ plume)	The dispersing volume of CO ₂ in a geological formation.
pore; porosity	A discrete void within a rock, which can contain air, water, hydrocarbons or other fluids; in a body of rock, the percentage of pore space is the porosity.
pre-competitive data	Data acquired for public dissemination, issued to encourage bidding by exploration companies for land over which they will be granted an exclusive exploration right.
pressure (differential)	The change in force per unit area between the reservoir pore pressure and the wellbore fluid pressure.
PSSA	Petroleum Search Subsidy Act.
reservoir	Sub-surface geological formation comprising porous rock that could contain oil, natural gas, CO ₂ or other fluids.
reservoir engineering; reservoir engineer	A branch of engineering dealing with the behaviour of fluids in reservoirs.
saline formation; saline reservoir; saline aquifer	Sediment or rock body containing brackish water or brine.
seal	An impermeable rock that forms a barrier above and around a reservoir such that fluids are held in the reservoir.

seismic: 2D, 3D, 4D.	Seismic – geophysical technique involving the transmission of sound waves and their reflection and refraction of this energy off subsurface geological boundaries. This data can be interpreted to produce geological cross-sections, i.e. extent and geometry of rocks sequences and their composition and fluid properties; 2D – a group of seismic lines acquired individually to produce a series of 2 dimensional cross-sections; 3D – a set of multiple, closely-spaced seismic lines that provide a 3 dimensional image of subsurface geology; 4D – comprises a series of identical 3D seismic data sets acquired at different times over the same area to assess changes in a reservoir with time.
storage	Injection of carbon dioxide into a suitable geological basin comprising porous sandstone for long term storage.
storage development	Elements include: pre-exploration, exploration, appraisal, development, construction and operation, described in the diagram below.
structural geologist	A geoscientist trained in the study of structural geology.
sandstone	A clastic sedimentary rock composed of fragments of sand.
sequestration; geo-sequestration	Long term storage of CO ₂ in geological formations.
stationary emissions	Emissions of CO ₂ from industrial processes and power generation facilities that operate at a fixed location.
supercritical phase	At a temperature and pressure above the critical temperature and pressure of the substance concerned. The critical point represents the highest temperature and pressure at which the substance can exist as a vapour and liquid in equilibrium
Taskforce	The Carbon Storage Taskforce (see Appendix A).
tenement	A licence granted to allow exploration or production of a commodity.
Treasury	Australian Government Department of the Treasury.
UNFCCC	United Nations Framework Convention on Climate Change.
well	Manmade hole drilled into the earth to produce liquids or gases, or to allow the injection of fluids.

APPENDIX E: MONTAGE OF THE OFFSHORE GIPPSLAND BASIN

Offshore Gippsland Basin

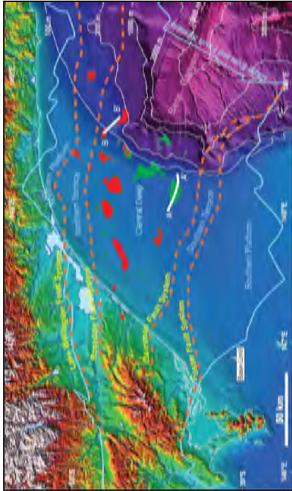
SOUTHEASTERN VICTORIA, OFFSHORE

Reservoir:
Top Latrobe formations and Golden Beech Subgroup, and Intra-Sirzelecki, Intra-Seaspray groups

Seal:
Lakes Entrance Formation, Kipper Shale, and basal Halbut Sub-group

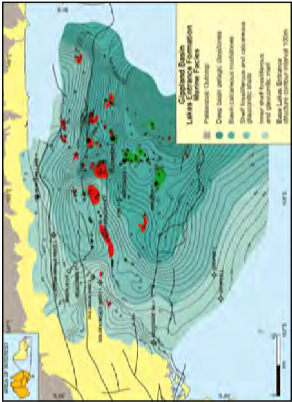
HYDROCARBON POTENTIAL
CATEGORY 1 and 2* (OGRA 2005)
Crude oil MMBL 278.28
Condensate MMBL 130.92
LPG MMBL 174.85
Sales gas Tcf 7.35
*data from entire basin

STRUCTURAL ELEMENTS



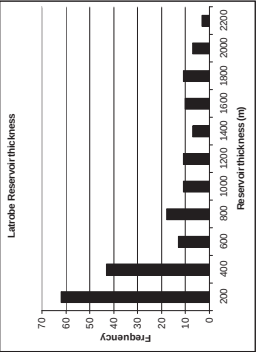
(After Bernecker and Partridge, 2001)

REGIONAL SEAL AREA

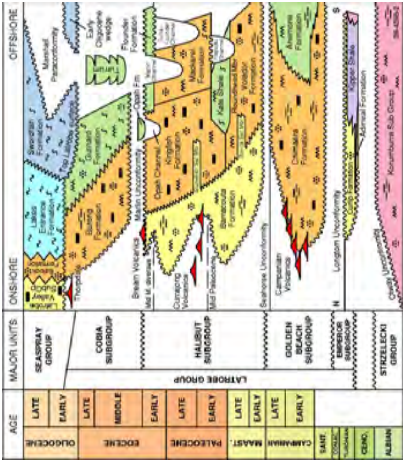


(After O'Brien et al., 2008)

RESERVOIR THICKNESS

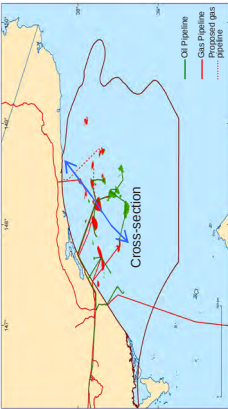


STRATIGRAPHY

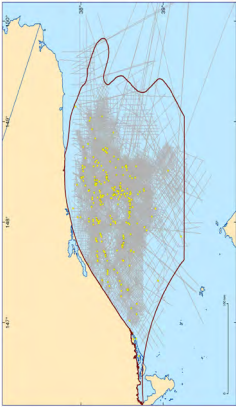


(After Bernecker and Partridge, 2001)

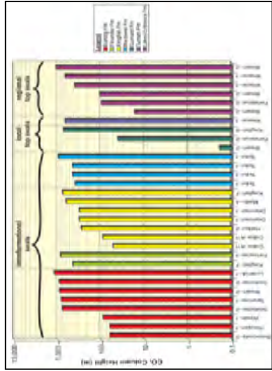
OIL AND GAS FIELDS



WELLS AND SEISMIC COVERAGE

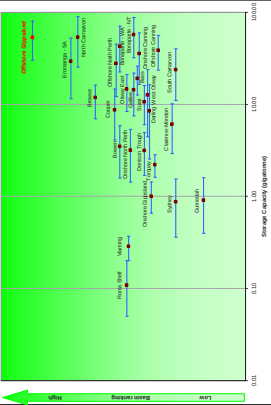


TOP SEAL POTENTIAL

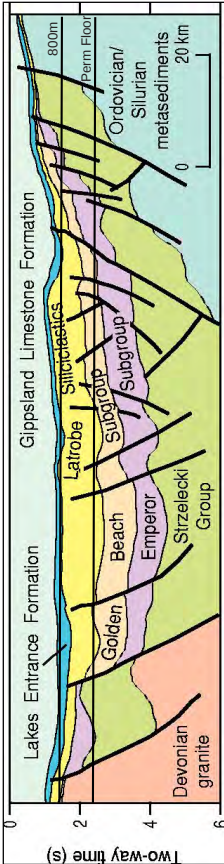


(After Gibson-Poole et al., 2006)

BASIN RANKING VS. CAPACITY

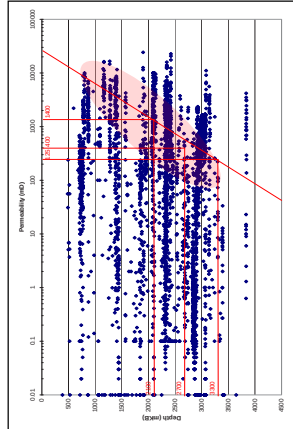
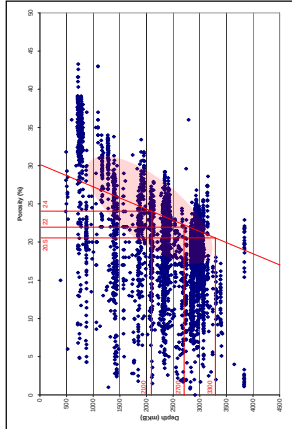
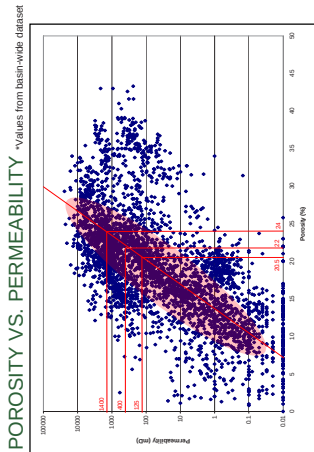


REGIONAL CROSS SECTION (LOCATION IN OIL AND GAS FIELDS MAP)

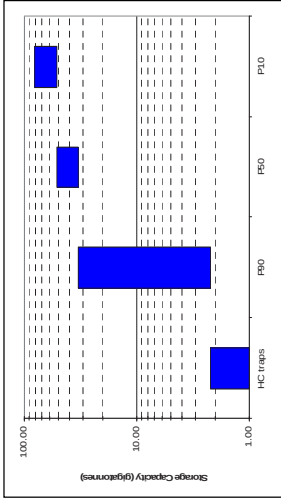


(After Power et al., 2001)

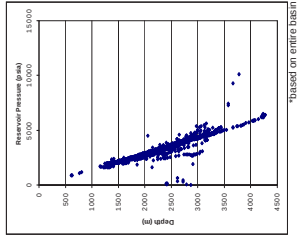
Offshore Gippsland Basin



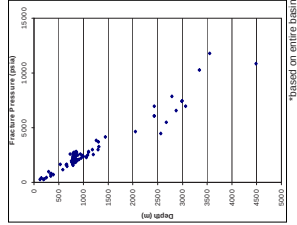
STORAGE CAPACITY



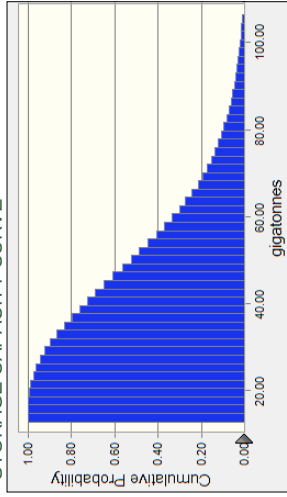
RESERVOIR PRESSURE VS. DEPTH - CSIRO PressureFit



FRACTURE PRESSURE VS. DEPTH - CSIRO PressureFit



STORAGE CAPACITY CURVE



BASIN RANKING

Category	Description	Score	Weighting
Tectonics (Seismicity)	Medium/Low	4	0.00
Size	Large	3	0.06
Depth	Intermediate	3	0.10
Type	Non-marine and Marine	2	0.04
Faulting intensity	Limited	3	0.14
Hydrogeology	Good	3	0.04
Geothermal	Moderate	2	0.05
Hydrocarbon potential	Giant	5	0.05
Maturity	Over-mature	5	0.05
Coal and CBM	Deep	3	0.00
Reservoir	Excellent	5	0.16
Seal	Excellent	5	0.18
Reservoir/Seal Pairs	Excellent	4	0.03
Onshore/Offshore	Shallow/Offshore	2	0.00
Climate	Temperate	5	0.00
Accessibility	Acceptable	3	0.00
Infrastructure	Extensive	4	0.00
CO ₂ sources	Major	4	0.00
Knowledge level	Extensive	4	0.05
Data availability	Excellent	4	0.05
Overall Ranking			1

STORAGE CAPACITY ESTIMATE

Parameter	Unit	Score (P90)	Score (P50)	Score (P10)	Distribution
Area of storage region	km ²	10000	16000	30000	Triangular
Gross thickness of saline formation	m	200	500	900	Triangular
Average porosity of saline formation over thickness interval	%	19	22	25	Triangular
Density of CO ₂ at average reservoir conditions	tonne/m ³	0.5	0.6	0.7	Triangular
E-storage efficiency factor (% of total pore volume)	%	4	4	4	
Calculated storage potential	gigatonnes	31.0	48.8	78.3	

POTENTIAL INJECTION PARAMETERS

Parameter	Unit	Shallow	Mid-Depth	Deep
Depth base seal	m	1600	2000	2400
Formation thickness	m	500	700	900
Injection depth	m	2100	2700	3300
Porosity	%	24	22	20.5
Absolute permeability	mD	1400	400	125
Formation pressure	psia	3030	3900	4760
Fracture pressure	psia	5460	7010	8570

APPENDIX F: BACHU RANKING CRITERIA FOR SEDIMENTARY BASINS FOR CO₂ STORAGE

The following Table 11 shows the Bachu ranking criteria for sedimentary basins being considered for CO₂ storage as originally proposed:⁹²

Table 11: Bachu ranking criteria

CRITERION	CLASSES				
	1	2	3	4	5
1 Tectonic setting	Convergent oceanic	Convergent intramontane	Divergent continental shelf	Divergent foredeep	Divergent cratonic
2 Size	Small	Medium	Large	Giant	
3 Depth	Shallow (<1,500 m)	Intermediate (1,500–3,500 m)			
4 Geology	Extensively faulted	Moderately faulted and fractured	Limited faulting and fracturing, extensive shales		
5 Hydrogeology	Shallow, short flow systems, or compaction flow	Intermediate flow systems	Regional, long-range flow systems; topography or erosional flow		
6 Geothermal	Warm basin	Moderate	Cold basin		
7 Hydrocarbon potential	None	Small	Medium	Large	Giant
8 Maturity	Unexplored	Exploration	Developing	Mature	Over mature
9 Coal and CBM	None	Deep (>800 m)	Shallow (200–800 m)		
10 Salts	None	Domes	Beds		
11 On/Offshore	Deep offshore	Shallow offshore	Onshore		
12 Climate	Arctic	Sub-arctic	Desert	Tropical	Temperate
13 Accessibility	Inaccessible	Difficult	Acceptable	Easy	
14 Infrastructure	None	Minor	Moderate	Extensive	
15 CO ₂ Sources	None	Few	Moderate	Major	

The amended criteria used in this study are given in Table 2 in Section 4.1.2 in the main body of this report.

⁹² Bachu, S., *Screening and Ranking of Sedimentary Basins of CO₂ in Geological Media in Response to Climate Change*, Env. Geol., 44:277-289 (2003).

APPENDIX G: DISCUSSION OF THE METHODOLOGY FOR BASIN STORAGE CAPACITIES USED IN THIS STUDY

The calculation of the storage capacity of saline aquifers in a sedimentary basin is the subject of ongoing research by scientists working in the field. This is partially because of the absence of detailed empirical field data as there is only one project that has been operating for more than ten years and this one has only injected a minor fraction of what that particular reservoir is believed to be capable of holding. All storage capacity estimates are therefore theoretical based modelling and experience with petroleum.

In general most researchers would recommended a 'bottom-up' assessment methodology which involves detailed geological analysis and the building of detailed reservoir models in which the flow of the CO₂ through the formation can be mathematically modelled and the efficiency of the various trapping mechanisms assessed.

However this type of detailed assessment is very time consuming could not be carried out in the timeframe of this Taskforce. Thus, the Taskforce adopted a more generalised 'top-down' assessment, using an accepted methodology.

Storage calculations for individual sedimentary basins reached in this study are based on a modified version of the methodology proposed in the US DoE Carbon Sequestration Atlas of the United States and Canada published in 2008.

The method essentially makes a volumetric assessment of the available pore volume in the reservoir formation within the basin based on reservoir thickness and area below a sealing lithology, which is deeper than the minimum required for the supercritical phase of CO₂. In the current study a probabilistic methodology was applied.

The calculations made in this study were at a very high level, and because of the time constraints used available data and mapping and did not include any detailed mapping of seal and reservoir pairs which would normally be required for a full evaluation.

The main factors affecting the selection of carbon storage sites are location (i.e. the distance from the CO₂ source to the storage location giving pipeline costs), reservoir depth (giving well costs) and injectivity parameters (notably permeability and differential pressure, which dictate the number of wells required).

In order to estimate the cost, and hence economics, of carbon transport and storage, the workgroup proposed three representative locations in each of the top ranked basins. These three chosen locations represented a shallow, mid and deep location⁹³ for injection of CO₂, in order to characterise the range of possible transport and storage locations.

Basin permeabilities were derived from core data using the following method (with the data on pressure, permeability and porosity as shown for each basin on the basin montage):

1. Three representative locations representing a shallow, mid and deep injection site in the basin were selected and injection depths determined.
2. A straight line was fitted to the porosity depth cross plots that characterised the porosity of the better sands with depth.⁹⁴ This line was drawn near the upper edge of the cross plot and assumed

⁹³ The parameters for the shallow, mid and deep location for each basin are tabulated on the basin montages in Appendix D in the table entitled 'Potential Injection Parameters'. Note: in two basins, the Bass and Darling, less than three points were modelled due to data or technical constraints

⁹⁴ Diagrams showing porosity and permeability data as a function of depth, with the estimation lines included, are shown on each of the basin montages. For an example, see Appendix E.

that injection of CO₂ will be into the better sands. The porosities corresponding to shallow, mid and deep depths were read off the interpreted line.

3. A visual 'best fit' was drawn on the porosity permeability cross plot, and permeabilities were read off the line for the three porosities representing shallow, mid and deep locations.
4. If the permeabilities at the locations assumed were high (greater than 20mD⁹⁵), these locations were used. If not, new surface locations were chosen with shallower depths, and steps 1 to 3 were re-iterated. Modelling has shown that for permeabilities that are low (less than 20mD), injectivity is low and the field will require many wells, making injection uneconomic.⁹⁶

Where pressure data was available, the data was used to estimate formation and fracture pressures. Where this data was not available, the fracture pressure was estimated by analogy with nearby basins. The basin temperatures were derived from Geoscience Australia's database.

In this way, information was developed for each of the selected basins on the probable porosity, permeability, pressure and temperature, and hence CO₂ density, at three selected locations in the basin. This data is presented in each of the basin montages, and was used as input data for calculation of the spacing, number and depth of wells for CO₂ injection at each of the locations. This, in turn, was used for calculation of the costs of CO₂ transport and storage in the basins.

A critical factor in this assessment methodology is the storage efficiency factor, E, which is that portion of the basin's total pore volume that the CO₂ is expected to actually contact as it moves away from the injection points. This value assumes that injection wells can be placed regularly through the storage basin and does not take into account areas that may not be accessed because of an inability or unwillingness to locate an injection well in that part of the basin.

In the DoE analysis a series of Monte Carlo analyses were carried out to calculate a value for the E factor which resulted in a range of 1% to 4% for a confidence range of P15–P85 intervals with a P50 case of approximately 1.8% to 2.2%.

Based on the work done in the DoE Atlas, a storage efficiency factor of 4% was applied to the calculated pore volume to estimate the storage available for CO₂. This is probably on the high side but acceptable given the high level nature of the assessment. Probabilistic storage capacity estimates were made for the key basins. These were based on Monte Carlo Simulations using the Crystal Ball software programme.

The basins selected for analysis included not only the highest ranked basins but also a number of mid-ranked basins whose geographical location relative to concentrated emission sources might offset to some degree their lower ranking.

⁹⁵ 'mD' refers to a measure of rock permeability: 'milli Darcy'. High values of mD imply that fluid moves easily in the rock under the influence of injection pressure and indicates that the rock has high 'injectivity'.

⁹⁶ Note that, in some basins, the 20mD reservoir lower limit necessitated a re-calculation of basin storage capacity because the available reservoir thickness interval was smaller than first thought.

APPENDIX H: METHODOLOGY FOR DETERMINING HUMAN AND OTHER RESOURCE REQUIREMENTS FOR THE APPRAISAL AND DEVELOPMENT PHASES OF CCS DEVELOPMENT

Storage Area Calculations

For the purposes of this assessment, the nominal storage area required per basin/demonstration site was calculated using the basin parameters derived by the Taskforce in calculating the basin storage capacity and the injectivity parameters for specific representative locations within these basins, as discussed in Section 4 in the main body of the report and Appendix F. These parameters are also reported on the basin montages. The storage area was calculated as follows:

$$\text{Area} = (\text{capacity}_{\text{CO}_2} * t_{\text{inj}} * 1000) / (\Phi_{\text{res}} * d_{\text{res}} * \text{ntg} * E * \rho_{\text{CO}_2})$$

where:

Area = storage area in km²

Capacity_{CO2} = target CO₂ storage capacity (Mtpa)

t_{inj} = injection period (years)

Φ_{res} = reservoir porosity (%)

d_{res} = reservoir thickness (m)

ntg = net/gross reservoir ratio

E = storage efficiency (%)

ρ_{CO2} = density of CO₂ (kg/m³)

The density of CO₂ was derived from a knowledge of CO₂ properties and reservoir temperature and depth using charts for onshore and offshore basins derived using the MIT calculator and assuming that pressures are hydrostatic. These charts are shown below in Figure 47 (offshore) and Figure 48 (onshore).

Figure 47: Offshore basins – density of CO₂ versus depth for different geothermal gradients

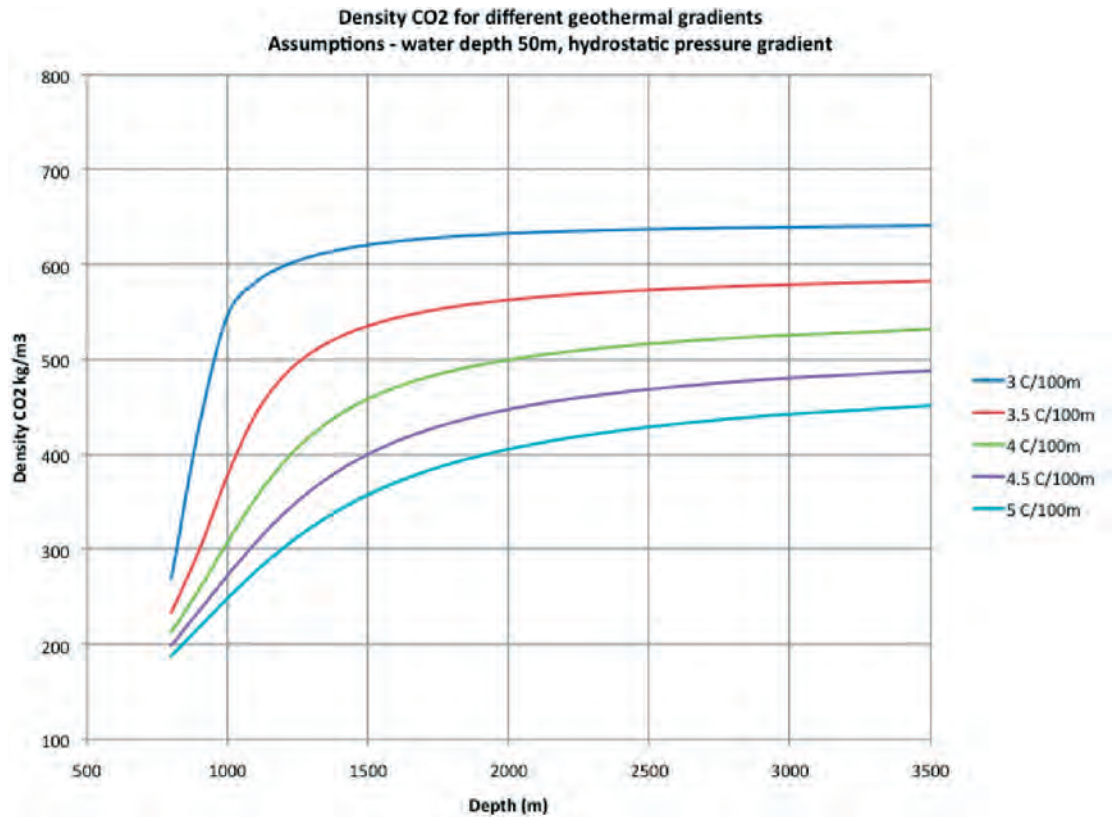
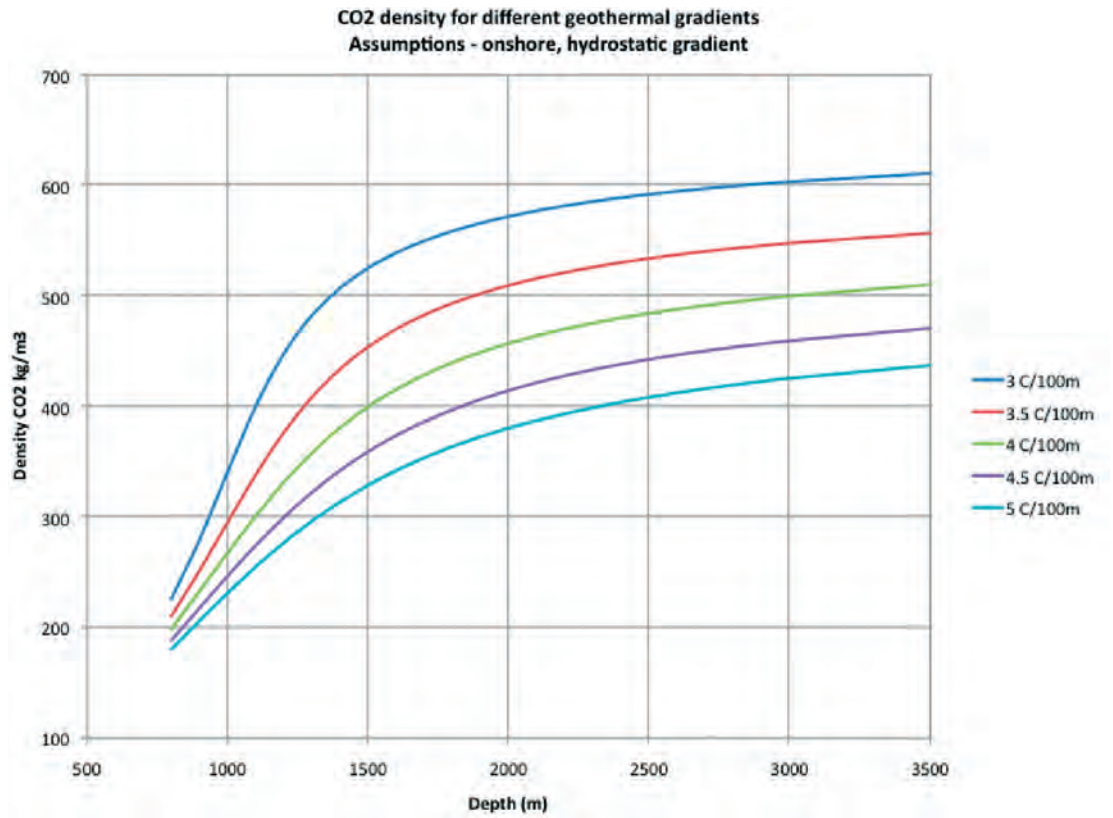


Figure 48: Onshore basins – density of CO₂ versus depth for different geothermal gradients



The parameters used are summarized in Table 12 below. The estimation of storage area assumed that storage efficiency, E, was 4% and the injection of CO₂ occurs for 25 years. The storage area was then used to calculate an exploration lease size that was twice the size of the storage area.⁹⁷

Table 12: Storage area parameters and modelled lease areas for storage basins

POTENTIAL STORAGE BASINS	CAPACITY (Mtpa)	ΦRES (%)	DRES (m)	NET/ GROSS RATIO (%)	GEO- THERMAL GRADIENT (°C/100m)	RES. DEPTH (m)	ρCO ₂ (kg/ m ³)	AREA (km ²)	PERMIT AREA (km ²)	GRATI- CULAR BLOCKS
Galilee	16	19	100	80	4.3	1400	330	1994	3987	55
Surat	50	15	100	80	2.9	1800	560	1674	3348	47
Eromanga	34	17	100	80	4.4	1700	420	1751	3501	49
Gippsland	31	22	500	40	3.7	2500	500	511	1023	14
Bass	18	16	400	40	4.4	2650	450	1392	2784	39
Otway West	5	23	300	70	3.8	2200	530	160	320	4
Perth onshore	10	20	100	90	4.4	2250	580	599	1197	17
Canning onshore	7	18	200	50	3.2	2000	550	631	1263	18
Carnarvon	9	20	100	70	3.6	3100	570	783	1566	22
Bonaparte	5	15	250	90	3.6	2500	570	162	325	5
Gippsland onshore demo.	3	24	150	50	3.3	2700	560	186	372	5
Roma Shelf demo.	3	22	100	80	2.9	1800	560	190	380	5
Denison Trough demo.	3	11.5	95	90	3.2	1250	440	433	867	12
Perth onshore demo.	3	20	100	90	4.4	2200	580	599	1197	17

It is interesting to note for some basins, such as the Galilee, the storage area is large for relatively modest injection rates, whereas basins such as Gippsland have a very concentrated storage area. This suggests that basins with thicker reservoirs will have a more commercially efficient outcome.

Exploration Phase Activities

The focus on activity in the Exploration phase is on finding a storage site suitable for containing the desired volume of CO₂. This means developing a 'storage play concept' through basin studies, reviews of existing data, seismic reprocessing and acquisition etc, and then testing the concept through drilling a series of wells aimed at proving that it is likely to be viable. There may be several storage site possibilities within the exploration lease area.

The intensity of exploration activity is largely a function the geology of the basin (its complexity and variability) and the knowledge and data that already exists. If the reservoir or seal are thin, drilled well

⁹⁷ The explorer will need to start with a lease area that is significantly larger than the calculated area to take account of geological uncertainties and risks. Also, an implicit assumption in the calculation of storage area is that the geological dip is relatively low. If there are dipping strata at the injection area, it is likely that the storage area could be larger, as the CO₂ plume will tend to migrate up dip for some distance. Doubling the storage area size makes some allowance for this.

and seismic data needs to be acquired at a closer line spacing than for a thick reservoir and seal because of the potential for faulting and/or facies variations to impact on reservoir continuity or seal integrity.

The approach used to estimate activity levels uses the amount of existing seismic and well data in each basin. Where there is already a significant amount of data, then less data needs to be acquired. Conversely, where data is sparse, a greater amount of data acquisition is needed. However, almost all existing data was collected for the purposes of the petroleum industry and there may be some differences in the nature of required. The approach is statistical, using the number of wells in the basin (exploration and appraisal) to calculate how many wells are likely to be present in the storage exploration lease.

If there are many wells in the lease, then it is likely that less core will need to be cut, which affects the cost estimate for the well. The acquisition of fresh core data is important for storage risk assessment. It provides data on seal integrity, reservoir geochemistry and compatibility with CO₂ etc. The time taken to complete core analyses is also a significant factor affecting the time taken to evaluate a storage site. Some analyses can take up to twelve months to complete. The number of wells to be drilled is determined by the required exploration well spacing.

Likewise, knowing the seismic line spacing and storage area, an estimate can be made of how much seismic data is present in the lease and therefore how much reprocessing is required. Similarly, having a target line spacing for the exploration lease and knowing the area, the amount of seismic acquisition can be calculated. For offshore permits, this may be 3D seismic.

The area of 3D seismic to be acquired is set by the assumption that an operator would need to have 3D data available over the area where the CO₂ is expected to be stored, so that an adequate reservoir model can be constructed.

The injection area is calculated from the number of injection wells and well spacing, which are determined by coarse reservoir simulations made as part of estimating the carbon storage tariffs.

Table 9 in Section 10.3.3 shows the estimated required exploration drilling and seismic activities per basin, given the existing knowledge of the basin and taking into account the information on each basin presented in the basin montage and described previously.

Exploration risk

In modelling exploration expenditure, it is necessary to consider exploration risk. A storage explorer may take up a lease, but after drilling several wells may find that the geology in the lease is not suitable for storage or the seal may not be effective, etc.

As discussed in Section 4 of the report and Appendix F, Bachu (2003) developed a tool for the assessment and ranking of sedimentary basins for their suitability for CO₂ storage. This ranking methodology was modified for Australian basins.

Reservoir (depth, quality) and seal (faulting intensity, quality) contribute to 68% of criterion weightings. If the reservoir and seal is poor, the risk for the explorer is that the reservoir may not be adequate for storage or the seal may leak. Knowledge of the basin and availability of information/data contribute a further 10% of the basin. Where there is less knowledge and data, the risk for the explorer is greater.

It can be argued therefore that the modified basin ranking is a measure of the basin's storage potential or chance of success – the higher the score, the greater the chance that a storage site is present in the basin. The question then is how to translate the Bachu score to a probability of success. For this study, a 'rule of thumb' has been applied.

This highest scoring basin in Australia is the prolific oil- and gas-producing Gippsland Basin, which scores 3.94 (the maximum score possible is 4.17). The Gippsland basin is a strong candidate for CO₂ storage and the chance of finding a storage site is very high. The lowest basin score is around 2.0. By assigning a 0% Probability of Success (POS) to a score of 2.0, and a POS of 75% to a score of 4.17, the modified Bachu score has been converted to POS.

The criteria, weightings, scoring and overall score in terms of probability of success (POS) for each exploration basin is summarised in Table 10 in Section 10.3.4.

The prolific oil and gas basins have the best chance of success – Gippsland has the highest POS of 67%, followed by Carnarvon at 57% and Eromanga at 53%. The Galilee Basin, which has large unexplored areas, has the lowest POS at 33% (or 1 in three chance of finding a storage site). This means that in the Galilee, three exploration leases would be needed to deliver one storage site, on the basis of probabilities. The POS and modelled injection capacity are used to calculate the number of exploration leases required in each basin to achieve the target storage capacity.

Appraisal and Development Phase Activities

During the Appraisal phase, activities are directed towards assessing development concepts and gathering sufficient data to understand the uncertainties and risks. Typically, a higher degree of seismic and well control is needed, as is detailed analysis of core data, understanding of the reservoir and seal capacity and characteristics, rock chemistry, the structural framework and geo-mechanical characteristics and hydrodynamics of the system. A full understanding of possible resource conflicts, environmental and stakeholder issues will also be developed in this phase.

In the Develop phase, the final development concept is selected from the options identified during Appraisal. A detailed Field Development Plan (FDP) is then developed that is underpinned by detailed understanding of the reservoir characteristics, uncertainties and expected performance based on extensive reservoir simulation. This is a significant piece of work and is manpower-intensive.

The resources and skills required for the FDP are shown in Table 13. Once the FDP is completed, the Basis of Design is prepared, followed by the Front End Engineering Design (FEED). This activity is engineering-intensive.

The main report gives details of the people and other resource requirements for the Appraisal and Development phases of the CCS development process. The costs outlined below have been determined from these estimates.

Exploration

The exploration team size is determined by the amount of data to be reviewed and acquired. The smallest team (typically for a lease with no 3D seismic and less than 7 wells to be drilled) has 6 people comprising team leader, 1 geologist, 1 seismic interpreter, 0.5 petrophysicist, 0.5 geochemist, 0.5 structural-geomechanics specialist, 1 technical assistant and 0.5 geological and seismic operations person (as well as input from a reservoir engineer).

In permits with more drilling activity and 3D seismic acquisition, the team increases to 10 people comprising team leader, 2 geologists, 2 seismic interpreter, 1 petrophysicist, 1 geochemist, 1 structural-geomechanics specialist, 1 technical assistant and 1 geological and seismic operations person.

Appraisal and Development

Resource requirements as a function of Field Development Plan size are given in Table 13 below:

Table 13: Field development planning team resourcing for different scale projects

	SMALL FDP <\$500M		BIG FDP >\$1.5B	
	PEOPLE	DURATION (MONTHS)	PEOPLE	DURATION (MONTHS)
Geologist	2	9	2	18
Geophysicist	1	9	2	18
Reservoir Engineer	3	9	4	18
Production Technologist	1	9	1	18
Petrophysicist	0.5	9	1	18
Geochemist	0.5	9	1	18
Structural Geomechanics	0.5	9	1	18
Team Leader	1	9	1	18
Engineer	2	9	3	18
Drilling Engineer	1	9	2	18
Operations	0.5	9	0.5	18
Environmental/approvals	0.5	9	0.5	18
Technical Assistant	1	9	1	18
Total	14.5	9	20	18

For the Appraisal phase, a similar approach to that used for Exploration phase is used to estimate seismic and drilling requirements. The results are shown in Table 14.

Table 14: Estimated appraisal drilling and seismic activities per basin

	EST. EXISTING WELLS IN LEASE	WELLS PRE-1970 (%)	REQUIRED WELL SPACING (km)	REQUIRED SEISMIC SPACING (km)	APPRAISAL WELLS NEEDED	SEISMIC ACQUISITION NEEDED (km/km ²)	CORE PER WELL (m)	EXTENDED WELL TESTS
Galilee	17	20%	10	0.5	20	5981km 1994km ²	90	4
Surat	103	30%	15	1	7	2511km 864km ²	36	2
Eromanga	177	10%	10	1	18	2801km 648km ²	54	3
Gippsland	20	20%	10	3D	5	500km ²	54	2
Bass	7	10%	12	3D	10	1200km ²	90	4
Otway West	5	20%	7	–	3	–	54	2
Perth onshore	16	30%	10	1	6	599km 432km ²	54	3
Canning onshore	8	20%	10	0.5	6	2210km 432km ²	90	3
Carnarvon	25	10%	10	3D	8	240km ²	36	2
Bonaparte	2	10%	7	3D	3	240km ²	90	2
Gippsland onshore demo.	0	20%	10	–	2	–	90	2
Roma Shelf demo.	12	30%	10	1	2	285km 144km ²	90	2
Denison Trough demo.	3	20%	10	0.5	4	1300km 144km ²	90	4
Perth onshore demo.	16	30%	10	1	3	898km 130km ²	54	1

Additional activities in the appraisal and development phase include well integrity studies that assess the risk of leakage from existing wells and in some cases surveys to establish the well. Metocean⁹⁸ survey costs have not been included in offshore estimates. An allowance for baseline monitoring (environmental, seismicity etc) has also been made. Extended well tests of three months duration have been included in the activities. These tests allow boundaries within the reservoir to be identified, which is vital for field development planning.

Cost and time assumptions

All costs are in Australian dollars unless they are otherwise indicated. An exchange rate of US\$0.70 has been assumed.

Well cost and duration

Well costs are derived using well depths from the RISC report entitled *CO₂ Injection Well Cost Estimation For Federal Government Carbon Storage Taskforce*. The well costs are consistent with a

⁹⁸ Metocean: from 'meteorology' and 'ocean', describing the physical environment near an offshore oil and gas facility.

US\$100/bbl oil price environment. Mob/demob cost is assumed to be \$0.2million for onshore wells and \$2 million for offshore.

RISC have advised that logging/completion time varies from 3–6 days for onshore wells (depending on depth) and 4–7 days for offshore wells.

They have suggested the following discrete completion time based on depth:

LOGGING TIMES		
DEPTH (m)	ONSHORE (DAYS)	OFFSHORE (DAYS)
1500	3	4
2000	4	5
2500	5	6
3000	6	7

The spread rate for logging and coring is based on a rig rate and service/support rate provided by RISC for a US\$100/bbl oil price environment.

SPREAD RATES		
	ONSHORE (US\$K/d)	OFFSHORE (US\$K/d)
Rig Rate	25	250
Service/Support Rate	15	200

Coring assumptions are based on representative rates and are provided by exploration and production company drilling engineers and by Schlumberger.

CORING PARAMETERS	
Tripping rate – drill pipe	500m/hr
Tripping rate – BHA	3 hrs
Coring equip rental	US\$1000/d
Mob/demob	US\$120k
Coring rate	5m/hr
Core analysis/special studies	A\$2000/m
Special studies turnaround	6–12 months

All wells are assumed to have a 2 leg walkaway VSP as part of the logging program. This is an important survey for correlating well data with seismic data and facilitating good reservoir and geological modelling. It also gives rock properties information.

VSP – 2 LEG WALKAWAY	
Fixed cost – design, processing, mob/demob	\$210k
Depth costs	\$80/m
Time costs – truck, people	\$100,000/d
Survey timing	1.5 d/1000m
Special studies turnaround	6–12 months

Extended Well Tests

It is envisaged that an extended production test will be used as a means of investigating far field boundaries within the reservoir interval. These surveys will take between 3–6 months to complete. For the purposes of this exercise, 3 months duration has been assumed. Costs are estimated using duration and spread rate only as an indication of cost. Cost could be significantly more.

Well evaluation

The cost of assessing the risk of leakage from existing wells is estimated at \$15,000/well (based on estimates derived from several Schlumberger case histories). Some wells will also require well integrity surveys – physical surveys of the well. For estimating purposes, it is assumed that wells drilled earlier than 1970 will require well integrity surveys. A well integrity survey costs US\$300k per well (onshore, including mob/demob). The cost could reduce to between US\$50–100k per well excluding mob/demob). Offshore surveys would be considerably more expensive. For modelling purposes a well integrity survey cost of \$150,000/well is assumed. It is noted that in some cases, well abandonment may be required at a cost of US\$900k/well (onshore including mob/demob). These costs have not been included in the estimate. There can be significant differences in mobilisation costs between locations.

Re-entry into abandoned wells or earlier sidetracks poses significant challenges, especially offshore and may be an unresolvable risk.

Seismic cost and duration

Seismic costs and rates have been provided by exploration and production companies, Chief Geophysicists and by Schlumberger. The estimates assume that the current market for seismic is softening, and so prices are lower than rates currently are.

SEISMIC		
	LAND	MARINE
2D seismic acquisition	\$4500/km 600 km/month	\$2650/km 2400km/month
2D seismic reprocessing	\$125/km 400km/month	\$100/km 500km/month
2D seismic new processing	\$125/km 500km/month	\$100/km 700km/month
3D seismic acquisition	\$12,000/km ² 230 km ² /month	\$8,000/km ² 1250km ² /month
3D seismic processing	\$750/km ² 200km ² /month	\$600/km ² 300km ² /month

Labour rate

It is assumed that people cost A\$200,000 per year.

Results

The total cost of the Exploration, Appraisal and Development phases needed to deliver ~198 Mt storage capacity is estimated to cost ~\$6.1 billion. The expenditure is split roughly equally over the three phases – Exploration (\$1,872 million), Appraisal (\$2,058 million) and Development (\$2,203 million).

It is estimated that some 130 exploration wells and 100 appraisal wells will be drilled (or 340 string months). Some 60,000km of 2D seismic and 14,000km² of 3D seismic will be acquired (estimated to be 190 seismic party months). Table 15 benchmarks the storage drilling and seismic activity levels with that of the oil and gas industry.

For offshore areas, the level of activity is equivalent to that of the oil and gas sector for an entire year. For the onshore, activity levels are higher at 2–4 years. In particular, 2D onshore seismic would represent a dramatic increase over current levels.

Table 15: Storage activity levels compared with oil and gas activity levels

	OIL & GAS AV ANNUAL*	ESTIMATED STORAGE ACTIVITY	YEARS OIL & GAS EQUIVALENT
ONSHORE			
2D seismic	3171	54492	17
3D seismic	1312	5157	4
Exploration & Appraisal Wells	85	164	2
OFFSHORE			
2D seismic	31062	4480	<1
3D seismic	10984	8480	<1
Exploration & Appraisal Wells	51	69	>2

* Average Oil & Gas Activity 1998 – 2008. Source: APPEA

During the Construction phase, drilling will be at its peak, with in excess of 400 injector wells to be drilled in the three main east coast storage basins (Gippsland, Surat and Eromanga basins).

Table 16 shows the estimated activities and costs for onshore and offshore basins, and demonstration sites.

Table 16: Modelled activities and costs for onshore and offshore basins, and demonstration sites

ONSHORE BASINS	POS (%)	TARGET CAPACITY (Mtpa)	BLOCKS PER LEASE	LEASES	2D REPROC. (km)	2D SEISMIC (km)	WELLS	EXPLORE COST (\$M)	2D SEISMIC (km)	3D SEISMIC (km ²)	WELLS	EXTENDED WELL TESTS	APPRAISAL COST (\$M)	DEVELOP COST (\$M)
Galilee	32	16	55	3	1196	11962	30	237	5981	1994	20	4	189	91
Surat	38	51	47	7	9375	11719	28	276	2511	864	7	2	87	261
Eromanga	53	34	49	4	7003	5602	16	148	2801	648	18	3	160	261
Perth	39	10	17	3	958	3592	3	52	599	432	6	3	76	91
Canning	35	7	18	2	505	1263	6	58	2210	432	6	3	79	100
Total	118		19		19037	34173	83	770	14101	4370	57	15	590	804

OFFSHORE BASINS	POS (%)	TARGET CAPACITY (Mtpa)	BLOCKS PER LEASE	LEASES	2D REPROC. (km)	2D SEISMIC (km ²)	WELLS	EXPLORE COST (\$M)	2D SEISMIC (km)	3D SEISMIC (km ²)	WELLS	EXTENDED WELL TESTS	APPRAISAL COST (\$M)	DEVELOP COST (\$M)
Gippsland	67	31	14	3	12273	2100	3	117	0	500	5	2	222	261
Bass	37	18	39	3	16704	4477 2D	9	268	0	1200	10	4	458	207
Otway W	34	5	4	3	384	1800	3	91	0	0	3	2	153	100
Bonaparte	42	5	5	2	2599	1200	2	67	0	240	3	2	166	164
Carnarvon	57	9	22	2	12531	1200	14	420	0	240	8	2	317	261
Total	68		13		44491	6300 3D 4477 2D	31	963	0	2180	29	12	1316	2137

DEMONSTRATION BASINS	POS (%)	TARGET CAPACITY (Mtpa)	BLOCKS PER LEASE	LEASES	2D REPROC. (km)	2D SEISMIC (km)	WELLS	EXPLORE COST (\$M)	2D SEISMIC (km)	3D SEISMIC (km ²)	WELLS	EXTENDED WELL TESTS	APPRAISAL COST (\$M)	DEVELOP COST (\$M)
Gippsland	67	3	5	1	74	370 3D	1	22	0	0	2	1	27	98
Surat	38	3	5	3	457	571	3	35	285	144	2	1	31	98
Denison Tr.	33	3	12	3	520	2600	6	51	1300	144	4	1	47	104
Perth	39	3	17	1	479	599	3	31	898	130	3	3	47	104
Total	12		7			370 3D 3579 2D	12	140	2484	418	11	6	152	406