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NZCCS
PARTNERSHIP

CCS in New Zealand – Case Studies for Commercial Scale Plant Final Report

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WorleyParsons
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CSIRO

MWH
BUILDING A BETTER WORLD

BAKER & MCKENZIE

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FOREWORD

The NZCCS Partnership was formed in 2006 to create core knowledge, capability and understanding of the New Zealand options for CCS in order for New Zealand to be ready to adopt CCS technologies when they become available and as required. The Partnership includes government and industry contributors, and recognizes that if the global response to the threat of the increase in levels of atmospheric GHG is to be successful, then CCS has an important, if not vital part to play in the portfolio of technologies that will underpin that success.

In 2009, a consortium led by Transfield Worley Ltd was selected after competitive tender to undertake the research presented in this report. The report contains contributions from some of the leading practitioners on CCS globally in their respective fields. This research was supported by the Ministry of Science and Innovation (MSI) contract TRAN0901.

The work was commissioned because the Partnership felt that a better understanding was required of the technical and other hurdles that face the deployment of CCS at a commercial scale, with a specific focus on New Zealand but in a global context. This better understanding is required because good policy is based on a sound appreciation of the issues, but also to inform our future work program and to enable the Partnership to identify and focus on the issues that matter most so that the Partnership's scarce funds are well spent.

The end result is a comprehensive, detailed and robust assessment of CCS in the context of two hypothetical but New Zealand specific case studies. The report does not advocate CCS per se and is not designed to address public awareness or understanding of CCS. The work has traversed technical, social, environmental and policy issues and will contribute significantly to our understanding of CCS, to our understanding of the work that is necessary to ensure that CCS is an option for New Zealand, and to the quality of the regulatory regime that is necessary for CCS.

We believe this is an important project and that the Transfield Worley consortium has met the high expectations placed on them by the NZCCS Partnership.

Chris Baker
NZCCS Partnership

Rev	Description	Originator	Reviewer	TW Approver	Date	Client Approval	Date
0	Approved for Use	D Lind	S Dykes	S Dykes	08/2010	N.A.	-
1	Re-Approved for Use	D Lind	S Dykes	S Dykes	09/2010		

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Within the Transfield Worley office, I personally would like to thank **John de Bueger, Stuart Dykes** (for all his reviewing and editing advice) and finally **Jeanie Oxley**, who helped coordinate and pull all this study together.

A special mention should also be made to **Chai McConnell** and **Yuki Masuda** (from the WorleyParsons, Brisbane office) who completed the PEER Review on this report.

And especially thanks to the members of the **NZCCS Partnership** who took time away from work to attend the various review meetings in Wellington and provide feedback on earlier revisions of this report.

Finally, I would like to acknowledge the Ministry of Science and Innovation (MSI) who supported this work through the contract TRAN0901, reference number CONT-21185-CCS-TRANSFIELDAK.

Without all of your input we would not have the holistic view and quality of the report we have here today.

Danielle Lind
September 2010

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ATTACHMENTS

1. EXECUTIVE SUMMARY

Commercial scale Carbon Capture and Storage (CCS) in New Zealand is a complex subject. CCS involves a diverse range of issues requiring a holistic approach when considering implementation. This study was commissioned by the NZCCS Partnership (made up from interested Government departments and industry representatives) specifically to address the following question:

> *“If New Zealand were to deploy a commercial scale Carbon Capture and Storage Facility, what technical, commercial, regulatory, legal, and social considerations would need to be addressed and resolved?”*

A Transfield Worley (New Zealand) led consortium including Schlumberger (Australia), WorleyParsons (USA), Baker & McKenzie (Australia), Montgomery Watson Harza (New Zealand), and CSIRO (Australia) were tasked to address this question through the following study objectives:

- Provide an overview of the impacts of CCS development in New Zealand (NZ),
- Determine the barriers to any commercial CCS development,
- Identify any gaps in NZ knowledge, or capability, and
- Identify the opportunities or benefits of CCS within NZ.

The study was completed by the consortium members over an eight month period and broadly divided into three phases:

- A review of potential NZ CCS looking at the Technical, Legal, Environmental, and Social implications;
- Selection of two generic case studies; and
- Development of the case studies illustrating specific issues NZ will need to address before embarking with a CCS project.

The resulting report is aimed at providing sufficient information highlighting the impacts, opportunities, gaps and barriers around commercial scale of CCS for the NZ Government and industry stakeholders, using the two case studies to illustrate.

1.1.1 What is CCS?

CCS is a term describing a collection of technologies where carbon dioxide gas (CO_2) is captured from large point sources (usually emissions from process plants or power stations) and transported via a pipeline to a suitable geological formation, for permanent underground storage.

CCS can be retrofitted to an existing plant or included in the design of a new industrial facility. The motivation for implementing CCS is as part of the overall strategy for reducing global greenhouse gas emissions (GHGs). CCS is generally seen as part of a portfolio of approaches that could be employed to reduce NZ’s overall GHG emissions.

1.1.2 Carbon Emissions in New Zealand

New Zealand’s CO_2 emissions from the major carbon emitting industries are mostly small when compared to internationally accepted thresholds for commercial applications of CCS. Only a small number of New Zealand’s (NZ) existing power and process industries exceed these values and therefore would mostly likely be economic if a future CCS facility was to be retrofitted. Table 1.1 provides a summary of these major emitters and other potentially viable process industries.

Table 1.1: Industrial CO_2 Emitters Potentially Suitable for CCS

Location & Industry*	Existing CO_2 Separation?	Few Sources/ Venting?	CO_2 above 1MMT/y?
Marsden Point Oil Refinery	Y	N	Y
Glenbrook Steel Mill	N	N	Y
Golden Bay Cement Mill	N	N	Y
Huntly Power Station	N	Y	Y
Motunui Methanol Plants	N	Y	Y
Stratford Power Station (incl Peaker Plant)	N	Y	Y
Kapuni Urea Plant	Y	Y	N
Kapuni Gas Treatment Plant	Y	Y	N

**Note: The Tiwai Point Aluminium Smelter (the only major source in the South Island) has been discounted technically due to the low concentration of CO_2 (compared to the overall emissions) - this existing process would not support any retrofitted capture system.*

At the time this study was started the internationally accepted threshold was CO_2 emissions greater than 1 million metric tonnes per year (million MT/y). The G8 criteria was revised earlier in 2010 to take into account non-coal applications and for definition of large scale application of CCS now includes 800,000-1million MT/y for coal fired power plant but for non coal fired power plant applications it is 400-500,000 MT/y. However in this study the original threshold was only loosely applied, so the subsequent revisions made little difference.

1.1.3 The Case Studies

Two case studies were developed during this project based on generic assumptions designed to best illustrate the impacts of future CCS development from: existing and new plants, several industry sectors/processes (differing capture technologies) and different geology (regions). Industry scale (and resulting emissions) were also considered in these case studies, along with any downstream implications on environmental planning, social impacts, legislation and regulations.

The case studies covered two industries, plant ages, total likely emissions, and locations, these were: 1) an existing North Island gas-fired power station and 2) a new South Island processing plant (assuming a new lignite processing facility).

Case study 1 was a complex retrofit option (assumed to be in the Taranaki region) with a capital outlay of \$627 million NZ (over a 30 year lifetime) including: installation of a capture system on an existing power station (emitting 1 million tonnes of CO_2 per year); transport to and storage in an existing reservoir (30km distance). Economically the capital outlay and increased operating costs (including decreased power station efficiency and net output) was not offset by the savings from the recovered CO_2. Hence this case study illustrating a possible CCS retrofit was deemed uneconomic, and not feasible. This conclusion does not apply to all CCS retrofits on existing plant as each should be valued on their own merits, so the economic results seen case study 1 may not apply to all situations.

Case study 2 was a new plant (assumed in the Southland region and emitting 4 million tonnes of CO_2 per year) already containing CO_2 separation processes, so had much simpler plant modification requirements including: compression, transportation 100km and storage in an undeveloped reservoir. The resulting economics for case study 2 was more positive reflecting this reduced scope and assumed amenable sequestration requirements. Even at a $969 million NZ (over the 30 year lifetime, which includes contingency and disestablishment costs) the project supported a $25/tonne carbon cost.

Other gaps, barriers and opportunities highlighted by these case studies and the study investigations are summarised in the sections that follow.

1.1.4 Capture Technologies

The three retrofit technologies suited for carbon capture on the variety of NZ power and process industries include: post-combustion capture, pre-combustion capture and oxy-fuel combustion. A fourth option, that has also been classified as a “capture technology” in some literature, covers industries that already have some form of CO_2 gas separation process. In New Zealand this currently includes Kapuni gas treatment, the hydrogen manufacturing unit (New Zealand Refining Company at Marsden Point), and the Ammonia Urea plant (also at Kapuni).

At this stage, because there is no firm CCS project planned for any existing NZ plant all the capture technologies are possible but dependent on:

- CO_2 Point Source(s)
- Processes Present, and
- Timeframe for Implementation.

In terms of selecting a particular capture technology (assuming a CCS project is feasible and viable), the most important point is the timeframe for implementation. Future CCS facilities will have more technology options to evaluate than any developed in the say the next 5 years, as some technologies are more mature than others e.g. post-combustion CO_2 capture.

1.1.5 Carbon Transport

The preferred carbon transport mechanism is via underground pipelines for CCS. Trucking has not been considered as a viable alternative because of the large volumes required to be transported. New Zealand has existing onshore and offshore high pressure pipelines but only in the North Island. These existing high pressure gas lines are already utilised for electricity generation and feedstock and/or fuel gas supply to industrial process and utility plants. It is unlikely these pipelines will become available for CCS in the future (even if the required legislative changes are made).

If pipeline availability was not an issue (and these could be adequately isolated from the main gas networks) reusing these pipelines for a future CCS facility would also require additional compression stages. The design and operating pressures of these existing so-called “high pressure” gas pipelines is well below expected CCS injection pressures (up to 300barg in Taranaki) so these pipelines would not be valid for CCS service (the current operating pressure of the Maui pipeline is 42-48barg).

The additional compression stages would enable the transport of the captured CO_2, then provide injection at the carbon storage site. Alternatively if the pipelines were fully rated for CCS, only one compressor station may be required for both carbon transport and injection.

1.1.6 Carbon Storage

A suitable underground storage site for CO_2 is driven by geology and from the CCS project perspective this is the area that has the greatest technical uncertainty and associated risk. The key geological factors include:

1) Cap-rock integrity providing a suitable seal,

2) Permeability and porosity determining injectivity and capacity, and

3) Location (onshore is cheaper to develop than offshore).

Furthermore, the only method to confirm a potential reservoir is suitable for Carbon Storage is through exploration and testing. This is an expensive but unavoidable step and moreover does not come with guarantees of commercial success.

The process of CCS can be considered as closely aligned to the Oil and Gas industry (concerned with the extraction of hydrocarbons from sub-surface reservoirs). The CCS practitioners can and do use the same expertise to inject CO_2 into reservoirs. For instance, methane gas has been stored underground for decades and some relative risks have already been addressed or proven e.g. natural seismicity and faults are present in almost every hydrocarbon field in use.

NZ Options for CO_2 Storage

The types of potential geologic storage formations for storing CO_2 in NZ include depleted oil or gas fields, Enhanced Oil and Gas Recovery and Enhanced Coal Bed Methane (ECBM). The study initially reviewed all these options but concluded for New Zealand the best opportunities for future CCS would involve either depleted oil or gas fields. Hence the two case studies reflected these options.

1.1.7 Legal/Legislative Influences

New Zealand has not yet enacted a complete legislated framework specifically governing the capture, transport and storage of CO_2. Instead, the study focus has been to review the existing legislative frameworks which may be applicable to CCS activities In New Zealand. Overall, it was found the existing legal frameworks are either not applicable to CCS activities or address only limited aspects of the CCS project cycle. Table 1.3 illustrates the level of support the current New Zealand legislation and regulations has for CCS developments.

Table 1.3 Overview of the Suitability of Existing NZ Legislation to CCS

Current NZ Statutes	Exploration for CO_2 Site	Capture of CO_2	Transport of CO_2	Injection of CO_2	Closure, Storage -long term
Crown Minerals Act 1991	O			O	O
CM Petroleum Regs 2007				O	O
Continental Shelf Act 1964	O			O	O
Foreshore & Seabed Act 2004 *(NZ territorial waters)*	O			O	
Resource Management Act 1991		Y	Y	Y	X
RMA Amendment 2009		Y	Y	Y	Y
Building Act 2004 *(Construction of buildings)*		Y		Y	
Gas Act 1992/Gas Regulations 1993 *(Fuel gas transport)*			O		
HSE Pipeline Regulations 1999 *(Pipeline construction)*			Y		
Submarine Cables & Pipelines Protection Act 1996			Y		

Current NZ Statutes	Exploration for CO_2 Site	Capture of CO_2	Transport of CO_2	Injection of CO_2	Closure, Storage -long term
HSNO Act 1996/ERMA *(Transport by rail/road)*			O		
HS(Compressed Gases) Reg 2004 *(Transport by rail/road)*			X		
Climate Change Response Act 2008 *(CCS Projects)**	O	O			

Key:

Impacts Act/Reg = Y **Gaps** In Act/Reg = O **Barriers** In Act/Reg = X

**Note: There is a gap in the Climate Change Act (as it is currently written) that does not include CCS projects as a specified "removal" activity under the ETS, nor state when CCS projects will be included as such.*

The legislated gaps or potential barriers against CCS developments that were identified in the Resource Management Act (RMA) are around injection of CO_2 into geological structures, and the long-term monitoring of and liability for sequestered CO_2. In particular:

- The RMA imposes a duty on "every person" to avoid, remedy or mitigate any adverse effects on the environment (regardless of consent conditions), CO_2 is classed as a contaminant in this Act[i]
- Current consent durations are limited to 35 years, and
- Any previously stored CO_2 leakage (outside of a current valid resource consent) is likely to be liable for discharging a contaminant and subject to imprisonment or fines.

Storage of CO_2 would likely change the physical, chemical or biological condition of the receiving water or land via a variety of mechanisms (the least would be increased sub-surface pressure). The gaps and barriers for CCS injection and long-term storage would need to be addressed before a potential CCS project could be sanctioned. This however, does not imply that the RMA is the most suitable Act to do this as separate legislation may be more appropriate.

1.1.8 Environmental Impacts

Environmentally all significant factors could be addressed through the RMA with respect to a future CCS development (assuming the CO_2 contaminant and longevity issues raised in the section above are addressed). Under the RMA an assessment of environmental effects, a report that demonstrates minimising or eliminating effects of a development or activity on the environment is required as part of the consenting process. In this respect, the RMA was identified as the likely foundation Act for any future CCS Projects and under this Act there are a number of different processing options that could be considered.

The regional and district plans in each region will determine whether the activities will require resource consent. There is no national consistency in terms of how regional district plans assess and classify activities, and as a result CCS may be treated more simply or favourably depending on region or district where it is located. There is also no precedent set for CCS activities in New Zealand and as a result the approach taken by local Government in assessing such an application may be more cautious and time consuming than if there had already had been significant NZ experience and/or an established national framework for CCS activities.

Overall, sound site selection based on: 1) available sub-surface information, development of monitoring and verification program (along with appropriate mitigation to stop or control any releases); and 2) development of the regulatory system and framework to include CCS activities; will ensure all the Environmental, Health & Safety (EHS) concerns associated with CCS can be properly mitigated.

1.1.9 Social Impacts

The Consortium investigated the potential social issues and stakeholder concerns around CCS developments in New Zealand. The results confirmed that there may be a number of social perceptions and concerns that may adversely impact the future development of CCS in New Zealand. These include:

- The low levels of knowledge regarding CCS, its application and relative costs and benefits to the community,
- Lack of certainty regarding the viability of CCS in New Zealand, e.g. seismicity issues and leakage
- Distrust in the current government and industry engagement activities, and
- Opposition to technologies associated with coal mining and the burning of coal.

Early and transparent government and public engagement with a range of stakeholders (e.g. non-government organisations (NGOs) and industry) is critical to ensuring the success of a CCS projects in New Zealand.

1.1.10 Next Stages & Follow-up

As a result of this New Zealand CCS study (and given the barriers and shortfalls in the current New Zealand legislation and regulations will be addressed) several opportunities are deserving of further attention and investigation. These are:

- Develop a structured stakeholder education process early and implement before CCS projects become further advanced (beyond the current concept stages).
- Gather and assess exploration data for the preferred or most promising, future CCS sites through a collaborative approach with government and industry representatives. These should include NZ oil and gas industries representatives.
- Review of area zoning for future CCS storage permits (i.e. these are larger than the current oil and gas permit areas and interplay needs to taken into consideration) and resolve the key legal issues associated with CCS.
- Investigate Industry sector specific opportunities for CCS (e.g. propose joint ventures with each industry) to confirm existing NZ opportunities for CCS feasibility and viability.
- Develop a framework to assist local governments better assess CCS proposals and applications (e.g. environmental consent/permit).
- Gather information that is lacking with respect to the environmental impacts of future CCS project development, e.g. better understanding of subsurface effects (saline or ground waters), monitoring of the storage aspects (during operations and post-operations).
- Consider revising the NZ pipeline regulations (and Acts) to allow provision for transport of CO_2.

2. ABBREVIATIONS & ACRONYMS

AGR	acid gas removal
ASU	air separation unit
barg	bar gauge, unit of pressure (similar to atmosphere)
BCA	Building Consents Authority (NZ)
CaO	calcium oxide (cement process)
CCGT	combined cycle gas turbine (power)
CCS	carbon capture and storage, carbon capture and sequestration
CSA	Continental Shelf Act (NZ)
CMA	Crown Minerals Act (NZ)
CMPR	Crown Minerals Petroleum Regulations (NZ)
CSG	coal seam gas
CTF	coal to fertiliser (process)
CTL	coal to liquids (process)
DEA	dethanolamine
DGA	digycolamine
DIPA	di-isopropanolamine
DOE	Department of Energy (USA)
DRI	directly reduced iron
ECBM	enhanced coal bed methane
EGR	enhanced gas recovery
EHS	Environmental, Health & Safety
EOR	enhanced oil recovery
EPA	Environmental Protection Authority (NZ)
ERMA	Environmental Risk Management Authority (NZ)
ESA	electric swing adsorption
ESP	electrostatic precipitator
ETS	emissions trading scheme (NZ)
FID	final investment decision
FGD	flue gas desulphurisation
FTR	fired tube reforming (process)
FPSO	Floating, production, storage and offloading (vessel/ship)

GNS	Geological Nuclear Sciences (government research)
H_2	Hydrogen (gas)
HRSG	heat recovery steam generator
HSCGR	Hazardous Substances Compressed Gas Regulations (NZ)
HSEPR	Health & Safety in Employment Pipeline Regulations (NZ)
HSNO	Hazardous Substances and Noxious Organisms Act (NZ)
IEA	International Energy Association (USA)
IPCC	Intergovernmental Panel for Climate Change
GHG	Greenhouse Gas
IGCC	Integrated gasification combined cycle
KOBM	Kockner Oxygen Blown Machutte (furnace)
km	kilometre
kT/y	kilotonne/year
lb/MMscf	Pound per Million standard cubic feet (imperial unit of concentration similar to ppmv)
LTRDG	Land Transport Rule, Dangerous Goods (NZ)
MDEA	methyldiethanolamine
MEA	monoethanolamine
MED	Ministry of Economic Development (NZ)
MEFOS	Metallurgical Research Institute (USA)
MMT/y	Million Metric Tonnes per year
MPa	megapascals
MW	megawatts
N_2	Nitrogen (gas)
NG	natural gas
NGCC	natural gas combined cycle
NGO	Non-government organisation
NZ	New Zealand
NZU	NZ units of CO_2 (NZ ETS)
O^{2-}	Oxygen ion
O_2	Oxygen (gas)
PC	pulverized coal
PCC	post-combustion capture

POX	Phophorous Oxides (gases)
ppm(v)	parts per million (volume)
PSA	pressure swing adsorption
psia	pounds per square inch, unit of pressure
RMA	Resource Management Act (NZ)
SCR	selective catalytic reduction
Sink	carbon storage
TEG	triethylene glycol (process)
TSA	temperature swing adsorption
UCG	underground coal gasification (process)
ULCOS	ultra low CO_2 steel making
VSA	vacuum swing adsorption
v/v	volume per volume (unit of measure)
WGS	water-gas-shift (process)

3. STUDY OVERVIEW

This study on the impacts of commercial scale Carbon Capture and Storage in New Zealand was commissioned and funded by the NZCCS Partnership (through FRST, Foundation of Research, Science and Technology) comprising members from interested government departments and private companies) specifically to address the following question:

> *"If New Zealand were to deploy a commercial scale Carbon Capture and Storage Facility, what technical commercial, regulatory, legal, and social considerations would need to be addressed and resolved?"*

Transfield Worley (New Zealand) led a global consortium to investigate the issues surrounding commercial scale Carbon Capture and Storage (CCS) in New Zealand. The consortium members included: Schlumberger (Carbon Storage), WorleyParsons Reading (Carbon Capture), Baker & McKenzie (Legal & Legislation), Montgomery Watson Harza, MWH (Environmental), and CSIRO (Social/Stakeholder).

The intent of the study was to complete a broad based report that covered industry and government requirements. It allowed for collaboration among interested stakeholders. Furthermore, the collaboration provided sufficient detail and knowledge to determine what it will take for New Zealand (NZ) to follow global CCS developments and be assumed that NZ be in a position to undertake a CCS development when and if required.

3.1 Study Objectives

Specifically, the goals of the study are:

- Confirm broader impacts of CCS implementation and commercial scale facilities in NZ, including Technical, Commercial, Legal (and legislative), Environmental and Social;
- Determine the barriers to any potential commercial scale deployment of CCS in New Zealand;
- Identify the gaps in knowledge and/or capability for CCS Implementation, particularly in a New Zealand context; and
- Identify the potential opportunities and possible benefits for CCS within New Zealand.

3.2 Study Intent

The objective of this report is to capture the findings for commercial scale CCS, illustrated by the case studies. The intended audience for this final report are the members of the Consortium companies and the NZCCS Partnership.

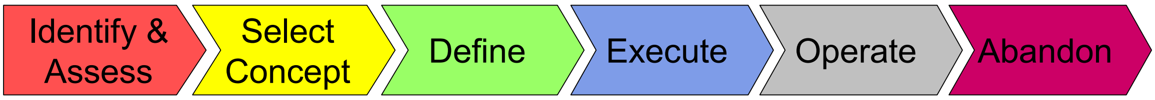
This final report (highlighting the opportunities and risks associated with CCS development in NZ) will be used by the NZ Government and Consortia Parties as a basis for decision making about future commercial scale CCS. This report may eventually end up in the public domain as supporting material to inform the public debate and further study around CCS in New Zealand. However, it has not been commissioned for this purpose and is not presented as such.

3.3 Study Methodology

Any commercial development of CCS in New Zealand is in the early project stages. While there are some prospective projects published in the media these are primarily exploratory in nature. Broadly speaking, commercial developments come with several investment periods:

- Preliminary “speculative” exploration or Identify & Assess phase(s) aimed at finding and assessing a site and sources sufficient to justify later investment, and
- A final “defined” design or FEED phase (Front-End Engineering Design) phase aimed at confirming project scope and actual expected project costs to +/-10%, requiring approval from an appropriate level (typically Board of Directors).

A generic project development process is shown below for a typical staged, gated capital project. Each phase is associated with an increasing level of capital exposure and ended by a decision gate which depending on Technical, Commercial, Economic and Regulatory confidence will yield a STOP, REVIEW or GO decision. At the time of writing this report there were no known projects being progressed into the Define/FEED phase in New Zealand.



The approach then, for this study of commercialisation of CCS within New Zealand was:

- To further the “Identify & Assess” work already completed by numerous parties,
- Leverage off the work already completed by the Transfield Worley (TW) lead Consortium Partners, and provide multi-disciplined international and national experience to the framework for the next steps for NZ CCS commercial scale plant.

To achieve this, the study was divided into three phases.

3.3.1 Phase 1: CCS Review & Data Collation

Phase 1 involved identification and evaluation of potential New Zealand carbon sources and sinks (storage). A preliminary review highlighting any gaps, barriers or opportunities was also completed in this phase covering:

- current Legal/Legislative (Baker & McKenzie),
- Stakeholder/Social perceptions (CSIRO),
- Environmental planning(Montgomery Watson Harza, MWH), and
- Local and Technical implications (TW and WorleyParsons, WP).

Phase 1 drew heavily on the consortium member’s existing networks, clients, various databases, and studies to ensure all the relevant areas applicable to CCS development in New Zealand were covered.

The key deliverable from this phase of the work was a Preliminary Report summarising the potential impact of implementation of a CCS facility in New Zealand, if such a development were to be undertaken in the immediate future. Specifically this report included an overview of the NZ opportunities for CCS noting:

- Major industries and greenhouse gas (GHG) emitters,
- Carbon capture technologies,
- Carbon transport, potential reservoirs or storage options, as well as
- The initial environmental, social and legislative implications.

3.3.2 Phase 2: NZ Selection Criteria

Following Phase 1, two generic CCS case studies best illustrating potential New Zealand CCS opportunities were defined and reviewed during the face to face meeting with the NZCCS Partnership in Wellington on 31 March 2010. The selection criteria of the case studies was developed prior to this meeting then discussed and actual case studies confirmed.

The fundamental decision making behind the case studies was to select two generic examples that could illustrate the impacts, gaps and opportunities in New Zealand. Furthermore, these still had to be neutral enough so as not to include nor exclude any of the existing or future operators that may be interested in investing in such a technology.

3.3.3 Phase 3: Development of Case Studies

The final phase took the two case studies and developed the concepts to best illustrate potential, future carbon capture, transport, and storage developments in New Zealand. This study phase includes technical evaluation as well as economic estimates. It should be noted the overall goal of the study was still to highlight the broader impacts of any CCS development in New Zealand through the case studies, not confirm whether these particular case studies are commercially feasible.

4. WHAT IS CCS?

Carbon Capture and Sequestration or CCS refers to a set of technologies used for the capture, transport and geological sequestration or storage of greenhouse gases (GHGs), specifically carbon dioxide gas, CO_2. These capture, transport, and storage (via injection) technologies are already used in commercial applications in the NZ Oil and Gas industries, and includes downstream process plants. The difference is the application to CCS.

To implement CCS, a large point source of CO_2 is required e.g. from a fossil fuel fired power station or other process industry. Moreover the source must be relatively concentrated so CO_2 emissions are easily captured. These sources are the most likely to be commercially viable.

CCS is generally seen as a technology that forms one of a portfolio of options for reducing GHG emissions and could be applied to existing or new developments in New Zealand with large single source CO_2 emissions. It is limited in its application in that it is one potential solution for reducing emissions from large point sources (e.g. industries) and does not capture all the CO_2 emitted (typically sources state around 80%) . Other emission reducing solutions for industry may include improving plant performance (process tuning and optimisation) or upgrading to more efficient technologies.

4.1 Carbon Capture

Carbon Capture refers to the capture of CO_2 gases (from industrial emissions e.g. fossil fuel fired power stations, boilers or process plants). The capture technologies cannot be applied to all GHG emissions, so any methane or other GHG gases coming from the same point sources will not be captured and stored. These capture processes are varied and are categorised on suitability to the industrial process or type of plant.

- Post-combustion – involves removal of CO_2 using a solvent from the combustion flue gases e.g. combined cycle gas power stations, or pulverised coal plants.
- Pre-Combustion – where the primary fuel in the process is converted to syn-gas (by reacting with air, steam, and air to form a mixture of carbon monoxide and hydrogen) before being converted to CO_2 and separated from the hydrogen.
- Oxyfuel Combustion – in this process the primary fuel is combusted in oxygen (instead of air) and produces a flue containing water and a higher concentration of CO_2. The flue gases are then cooled to remove the water vapour, however, this process is suited only to those plants who have a supply of oxygen.
- Industrial Processes – these include CO_2 stripping or separation technologies in the normal process (without modification) e.g. natural gas processing, steel, cement or ammonia productions.

These capture processes essentially ensure the captured CO_2 is dry, purified (~99%) and compressed to high pressures to become a supercritical fluid[1], suitable for efficient injection at the storage site.

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[1] Supercritical CO_2 is where the temperature and pressure are at a point where it can exist as both a gas and liquid simultaneously (Burkitt et al. 2010)

4.2 Carbon Transport

Carbon transport is the method used to transfer the supercritical CO_2 fluid between the capture and storage locations. Ideally these two locations are as close as possible to each other to minimise capital costs and transfer is normally via an underground pipeline.

The CO_2 is maintained in supercritical state as it is the most effective means of transporting large quantities of CO_2 in a relatively small volume.

4.3 Carbon Storage

Carbon storage is the final act of safely sequestering or storing the CO_2 into suitable geological formations, through injection at supercritical conditions. The requirement for supercritical properties ensures the CO_2 injection process is completed most efficiently.

A good underground storage site for CO_2 is driven purely by geology and from the CCS project perspective this is the area that has the greatest technical uncertainty and associated risk/cost. The key geological factors when determining a suitable storage site for CO_2 include:

1) Cap-rock integrity providing a suitable seal;

2) Permeability and porosity determining injectivity and capacity, and

3) Location (onshore is cheaper to develop than offshore).

It should also be noted, the only method to confirm that a potential reservoir is suitable for carbon storage is through exploration and testing. Exploration and testing is an expensive but unavoidable step and does not come with any guarantees of commercial success.

4.4 Carbon Capture Ready

Carbon Capture Ready (CCR) is a term also frequently used in discussions concerning CCS. The term is used to describe a plant or process that is “ready” for the capture, transport and storage of its CO_2 emissions. The terms “capture ready”, “transport ready” and “storage ready” have also been used and in some cases international definitions have been proposed to distinguish from CCR.

The concept of CCR is subject to significant conjecture. Some proponents of CCR suggest that this is the first step of an existing or proposed process plant towards eventually being developed to become a fully integrated CCS project, if it is feasible. Critics however, argue that CCR is a means used by some stakeholders of abdicating commitment to reducing emissions via CCS. Given the many levels on which CCR could be interpreted, three levels of stringency were developed in order to give policy makers and regulators the flexibility to adapt the proposed definition to their particular jurisdiction (Burke and Henderson 2010):

- Level 1 has the lowest cost and time expenditures for compliance by project developers and allows the greatest flexibility,
- Level 2 increases requirements through a greater level of design development for the capture facility; selection of transport corridors; and enhanced modelling of storage location, including desktop study of injectivity, capacity, and integrity; and
- Level 3 identifies specific capture technologies to be retrofitted, requires acquisition of transport rights of way, establishes planning requirements, and requires geological exploration.

For the purposes of this study, CCR was not considered. The study analysis was conducted only on potential CCS projects only.

5. APPLICATIONS IN NEW ZEALAND?

New Zealand has a number of large single point sources of CO_2 that could potentially support CCS in the future. As stated, it is not the intent of this study to illustrate how this could be achieved for a particular plant. Rather, this study seeks to highlight what the general impacts would be if interested parties were to invest in CCS as a technology to assist reducing CO_2 emissions from an operating plant(s).

An overview of the current and potential future industrial carbon emissions and existing infrastructure in New Zealand is provided in the following sections, specifically focusing on those most likely to be suitable for future CCS facilities. As stated above, this section is only to provide a general overview of the type and the location of New Zealand's major CO_2 emissions, and to identify any infrastructure that may complement CCS now or in the future. This is purely for information and does not mean any of these industries or infrastructure are available or being considered for use in a CCS technology now or in the future[2].

5.1 New Zealand Overview

Overall, the majority of the CO_2 emissions from the major New Zealand carbon emitting industries are low when compared to internationally accepted "rules-of-thumb" thresholds for commercial applications of CCS[3].

While only a handful of New Zealand's (NZ) existing power and process industries exceed this, caution is required when applying thresholds as true CCS feasibility and viability will determined on a number of factors. This decision depends not only on the emission levels, but also the type of process being retrofitted, the concentration of CO_2, amongst other factors e.g. operating savings through NZ Emissions Trading Scheme (ETS), reductions in carbon emitted. For instance, there are also a few process industries that do not meet the threshold levels but are complementary to a retrofitted CCS facility because CO_2 separation steps are already an integral part of the processes.

The Ministry for Economic Development (MED) collates confidential air emission data from the major industrial CO_2 emitters in New Zealand. Several major process industries make up this list and cover a range of industry sectors including Oil & Gas (including upstream and downstream/petrochemical hydrocarbons industries), Energy & Power, Minerals & Mining (including steel, concrete and aluminium industries), and Food and Beverage industries.

Figure 5.1 provides a summary of the MED data and illustrates the approximate geographical locations of the major CO_2 emitting industries and groups these companies into approximate provincial or regional locations. Highlighted (in bold) are those companies whose CO_2 emissions exceed approximately half the "rule-of-thumb" threshold discussed above.

The most significant existing point sources of CO_2 emissions are mainly clustered in New Zealand's North Island. An overview of these major point sources follows in Figure 5.1.

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[2] Only publicly available data has been used, no private operating data has been made available from private operators or explorers to discuss further with respect to carbon storage opportunities in this study.

[3] 1 million metric tonnes per annum of CO_2 discharged was quoted as the rule of thumb for commercial applications of CCS but since this studies inception this rule of thumb has been revised early 2010 (under the G8 criteria) to now take into account non-coal applications as well as coal. The study was concluded using the original rule of thumb as this was loosely applied.

Figure 5.1: Overview NZ Major Process Industries

A: NORTHLAND
Marsden Point Refinery
Golden Bay Cement
Ngawha Geothermal Power Station (25MW)

B: AUCKLAND
BHP Glenbrook Steel Mill
Contact Otahuhu Power Station
Pacific Steel Mill

C: GREATER HAMILTON AREA
Genesis Huntly Power Station (1000MW)
Contact Cogen Te Rapa
Evonig Degussa Peroxide Plant
CHH Kinleith Pulp & Paper
Fonterra Dairy Cogen, Te Awamutu
McDonald's Lime Kilns & Quarry, Otorohanga
Perry Lime Kiln Quarry, Te Kuiti

D: ROTORUA
MRP Geothermal Power Stations & Cogen
(247MW, 175MW)
CHH Tasman Pulp & Paper

E: TAUPO
Contact Ohaaki-Broadlands Geothermal Power
Station (60MW)
Contact Wairakei Geothermal Power Station
(140MW)
Other minor geothermal stations

F: NEW PLYMOUTH
Methanex Methanol Plants
New Plymouth Power Station

G: SOUTH TARANAKI
Vector Kapuni Gas Treatment Plant
Ballance – Ammonia-Urea Plant
Fonterra Whareroa Cogen, Hawera
Contact CCGT Plant, Stratford (377MW)

H: HAWKES BAY
Webster's Hydrated Lime Coy.

I: WESTPORT
Holcim Cement

J: OAMARU
Taylor's Lime

K: INVERCARGILL
Rio Tinto Aluminium Smelter

CO_2 point sources shown in bold are around 0.5 million tonnes per year or greater.

3 major point sources are:
- Marsden Point Refinery
- Huntly Power Station
- Glenbrook Steel Mill

There are future CCS opportunities in New Zealand that include industrial processes which already separate the CO_2. These could potentially be retrofitted with relatively less equipment and therefore more cost effectively. These so-called "low hanging fruit" for potential CCS facilities include the: Refinery Hydrogen Manufacturing Unit, Kapuni Gas Treatment and the Kapuni Ammonia-Urea Plants and are closer to the G8 revised point source levels for CO_2 emissions.

Finally, the simpler the emissions, the simpler it is to retrofit carbon capture, so processes with fewer emission sources are obviously preferential over others that are more complicated. Of the major CO_2 emitters, Table 5.2 provides an overview of New Zealand's major emitters and brief details on the process plant which could potentially assist future CCS feasibility and viability.

Table 5.2: Industrial CO_2 Emitters Potentially Suitable for CCS

Location & Industry	Existing CO_2 Separation?	Fewer Stacks/ Vents?	CO_2 above 1MMT/y?
Marsden Point Oil Refinery	Y	N	Y
Glenbrook Steel Mill	N	N	Y
Golden Bay Cement Mill	N	N	Y
Huntly Power Station	N	Y	Y
Motunui Methanol Plants	N	Y	Y
Stratford Power Station (incl Peaker Plant)	N	Y	Y
Tiwai Point Aluminium Smelter [4]	N	Y	Y
Kapuni Urea Plant	Y	Y	N
Kapuni Gas Treatment Plant	Y	Y	N

Table 5.2 also implies that suitable carbon storage is identified close-by (in all examples) and full production (maximum emissions) from these industries is likely to continue for the foreseeable future. These assumptions will need to be confirmed if any further study work around CCS were to continue for these existing industries.

In Attachment 1 (Carbon Capture Technologies), the full report by WorleyParsons, Reading contains a thorough review of the capture technologies available and the applicability to NZ major emitters. Table 5.2 (above) only summarises some of this information at a high level.

5.2 Existing NZ Infrastructure

5.2.1 For Carbon Transport

The preferred carbon transport mechanism is via underground pipelines for CCS. This is based on several reasons:

- Underground pipework has a cheaper installation costs (than above ground),
- Underground pipework is more aesthetically acceptable to the public and stakeholders,
- There is a New Zealand precedent set for this type of installation (e.g. Taranaki and North Island),

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[4] *The Tiwai Point Aluminium Smelter (the only major source in the South Island) has been discounted technically. Although the total amount of CO_2 emissions is high enough to be considered for CCS, the fact these are very dilute (compared to the overall emissions) confirms this existing process would not support any retrofitted capture system. Refer Attachment 1.*

- The earth provides a natural insulation against fluctuating environmental temperatures (especially over long distances), and
- There is a natural buffer zone from the public.

Trucking of CO_2 was not a viable alternative to the installation of a pipeline as the likely scale and volume required would not be more cost effective. This would also have a greater environmental impact and potentially more complicated legislative problems to resolve (with respect to transportation of a contaminant). Therefore, this option has not been progressed any further in this study.

New Zealand has various gas and liquid pipeline networks particularly in and around the province of Taranaki where the majority of New Zealand Oil and Gas reserves have been developed. There are no high pressure pipelines in the South Island. Refer to Figures 5.3 and 5.4 for an illustration of this pipework infrastructure.

Note: The legend for both Figures 5.3 and 5.4 is located on Figure 5.4 (the following page).

Underground Pipelines (Onshore)

There are two main high pressure gas pipelines in the North Island: the Maui pipeline and a similar length Kapuni pipeline both running from Taranaki to Waikato/South Auckland.[5]

Other smaller pipelines run around the North Island supplying gas to Wellington, Central North Island and the East Coast. There are also numerous liquid pipelines that generally operate at even lower pressures than the gas pipelines.

All of these pipelines are currently utilised for oil and gas transport, gas supply to process plants or power stations, and currently play an integral part of New Zealand’s energy infrastructure. Further, the design requirements for the transport of CO_2 may not be satisfied by existing pipelines, not existing regulations. For instance, the Petroleum Regulations or Gas Act does not allow for pipeline transport of CO_2, only natural gas (fuel gas) (Beatty and Wong 2010).

Sub-sea Pipelines (Offshore)

There are several pipelines running from onshore to offshore including those linking to: Maui A and B, Pohokura (offshore Waitara/Motunui), and Kupe reservoirs. These pipelines carry gas and liquids from chemicals/power to the various platforms. Similar to the high pressure gas pipelines onshore, these pipelines are also unlikely to be rated for the very high injection pressures required with CCS.

Similarly, these pipelines connecting from operating platform facilities would not be available for current or future CCS activities, at least until the fields are considered commercially depleted and the operators are undertaking abandonment activities. At the time of writing this report there was no indication on when any of these assets may become available, if at all.

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[5] *“High” pressure is generally classified as pressure greater than 60barg (Sinnot, 1992) and these pipelines could be rated with maximum design pressures up to around 70barg. Operating pressures are usually much lower (42-48barg entry pressure in Taranaki (Anonymous_g, 2010) and these pipelines transport treated, reticulated gas for major process and power industry users.*

Figure 5.3: Overview - North Island Infrastructure

Source: Ministry for Economic Development, 2010

Figure 5.4: Overview - South Island Infrastructure

Source: Ministry for Economic Development, 2010

5.2.2 For Carbon Storage

The types of opportunities for storing CO_2 in New Zealand include:

- Depleted oil or gas fields,
- Enhanced oil or gas recovery (EOR/EGR), and
- Enhanced Coal Bed Methane (ECBM).

Depleted Onshore Oil or Gas Fields

Carbon storage is possible for utilising depleted reservoirs, filling the voids vacated by the hydrocarbons with pressurised supercritical CO_2. These reservoirs operate in the same principle as a very large underground storage tank but with two key points:

- The storage sites are not huge caverns but “solid rock” that act like a sponge, and
- CO_2 is not a gas at reservoir depth, but acts like a dense liquid.

New Zealand does have onshore underground storage of treated natural gas, e.g. the Ahuroa Gas Storage Project. This reservoir has been receiving reticulation quality natural gas (to the NZ standard for reticulated fuel gas, NZS5442) in Taranaki since 2009.

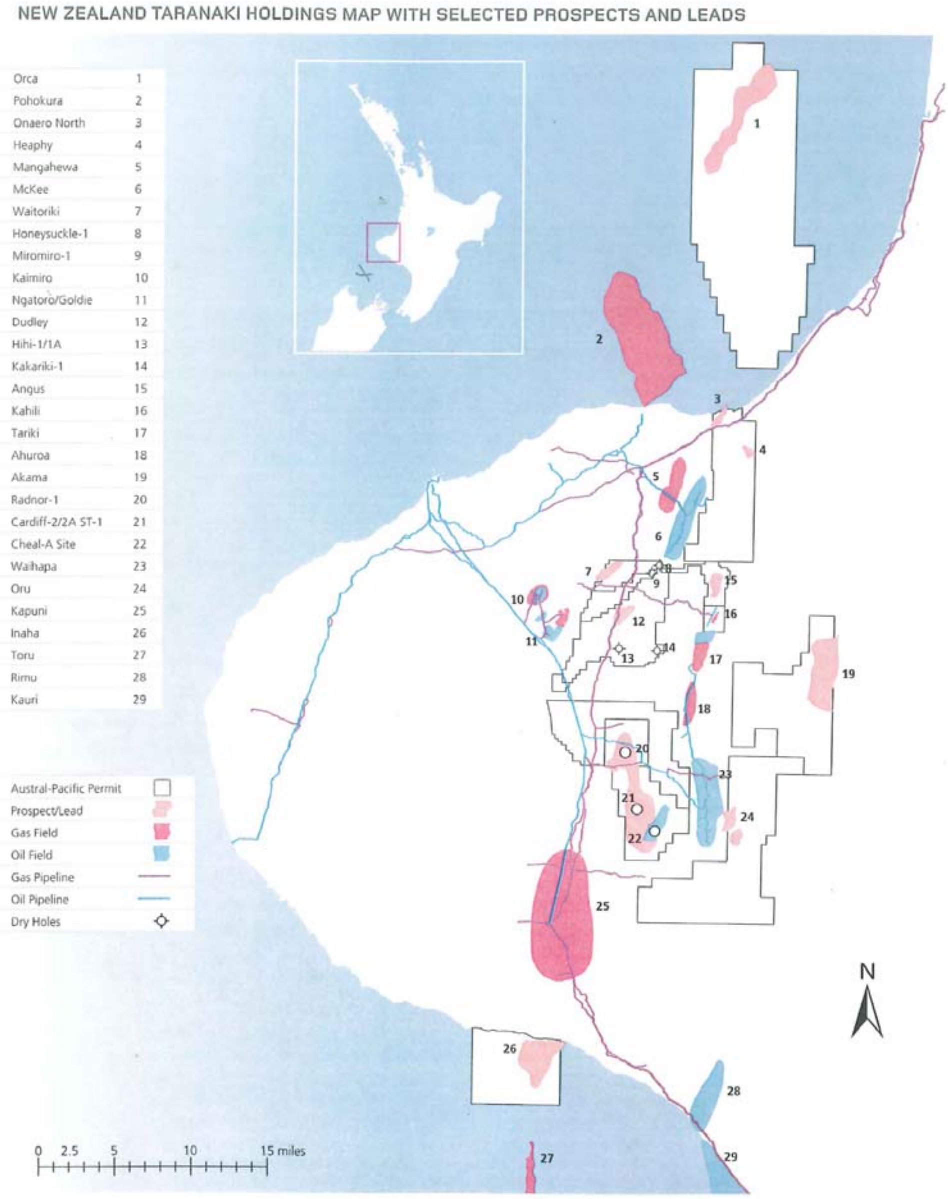
New Zealand has numerous developed, tested or partially developed oil and gas reservoirs, mainly in the Taranaki region (see Figure 5.5) that could be suitable for future CCS facilities, e.g. Tahora, Ngaere, Kahili, Kapuni and Maui. There are also two other commercially developed reserves (i.e. Tui and Maari) whose processing facilities occur on platforms with short operating lives (i.e. <15 years) or Floating Production, Storage and Offloading vessels (FPSO), so therefore are not connected directly to shore. Moreover, given none of these reservoirs are officially classified as depleted (even considering the length of operation for some) there is little likelihood these will be available for CCS as the injection and storage of CO_2 may even be detrimental to current or proposed operations.

Caution should also be taken with nominating a particular “depleted” field. This is because although there is more data on these reservoirs (as opposed to undeveloped or partially developed fields) this does not reduce the risks associated with injecting and storing CO_2. There are other concerns which will be addressed in later sections of this report, including legacy equipment not suited to the new CCS service, potential resource conflict, and simultaneous operations of injection with hydrocarbon production may be technically feasible but may adversely affect operational and financial viability.

An upside for use of depleted, NZ onshore and offshore fields (assuming further oil and gas exploration is no longer economical or viable) is some of these existing fields and facilities may be used for future CCS facilities. The positive is the reduction in abandonment costs of the process facilities (which are significant, especially offshore often by an order of magnitude) that will be saved by the operating company.

For example, there may be a possibility of reusing some of these process facilities and associated infrastructure for future CCS operations and post-operations. This would have to be confirmed through engineering and design to the latest codes and standards.

Figure 5.5: Onshore Reservoirs - Prospects & Leads



Source: Austral Pacific Energy, 2004

A potential upside for utilising a depleted offshore reservoir over a depleted onshore one is New Zealand has larger reservoirs offshore, hence greater storage volumes are possible. The economics will still have to be completed to determine if this is the case, should an offshore reservoir become available for CCS.

Undeveloped Reservoirs

Previous work through GNS (Geological Nuclear Sciences Ltd) and CO2CRC survey studies on major basins around New Zealand have focussed on capacity estimations and seal horizons. Other factors which would need to be considered before these areas can be confirmed as potential areas for carbon storage are injectivity and location.

EOR/EGR

Enhanced oil or gas recovery (EOR and EGR respectively) using CO_2 has been identified as a potential option for CCS in New Zealand. It needs to be noted that while this is possible, this not the same process as CO_2 storage and would be production driven with some CCS as a secondary benefit. Hence, this is not an ideal option for CCS in NZ. Table 5.6 summarises some of the differences between CO_2 storage and CO_2 EOR or CO_2 EGR that would need to be considered if these options were progressed.

Table 5.6: CO_2 EOR/EGR Versus CCS

	Enhanced Oil/Gas Recovery	Storage
1	CO_2 rate depends on Production Strategy (which may change over lifetime of activity e.g decrease)	CO_2 Injection Rate determined by source
2	CO_2 Recycled (recovered from reservoir gas)	CO_2 Stored
3	Legislated under petroleum industry	New CO_2 Regime required
4	No monitoring	Long-term monitoring
5	Revenue from Hydrocarbon	Revenue from price of Carbon
6	Low public awareness (outside of industry)	High public awareness

Note: Attachment 3 of this report provides a full report from Schlumberger discussing the issues around storage options in New Zealand.

ECBM

This stands for the “enhanced recovery of coal seam gas” through injecting CO_2 into the coal. Given that coal has a higher sorption capacity for CO_2 (compared to methane) it preferentially absorbs the injected CO_2 and desorbs the methane. However, the lower the rank coal the higher the ratio of CO_2 to obtain a unit of methane. Higher rank coal is more attractive for CO_2 storage applications. New Zealand generally has lower rank coals available, no seal rock, only thin seams of coal and overlaid with potable acquifers. This means the potential for safely storing CO_2 using this formation is limited in New Zealand. Refer to Figure 5.3 and 5.4 for approximate locations of these coal fields.

5.3 Future New Zealand

Several major projects have been announced or are underway in New Zealand that will have an impact on the countries overall carbon emissions. These include:

- Stratford Peaker Project (2 by 100MW CCGTs) currently being constructed for Contact Energy in eastern Taranaki. The location of this project is adjacent to the existing Stratford Power Plant.
- Solid Energy along with its partner Ravensdown has announced investigations into Lignite Conversion processes producing urea fertilisers in the Southland region. These investigations are feasibility studies and it is likely there will be some time (years) before a full-scale commercial development is sanctioned.
- Producing liquid fuels from Southland lignites is being investigated by Solid Energy.
- Coal Seam Gas (CSG) exploration work has been carried out by L&M Energy, Comet Ridge, and Solid Energy. While no company has developed a commercial CSG field, prospects appear positive and exploration continues for both. There is also the unanswered question of what the gases will be used for.
- Holcim Cement has also stated plans that it may build another Cement Plant on the South Island’s east Coast (near Oamaru).
- The summer of 2009/2010 has also been extremely busy with onshore and offshore drilling programmes in the Taranaki based petroleum sector. Depending on the resulting production, there may be some expansions in this region.

NZ Emissions Trading

The year, 2010 brings the start of a new emissions trading scheme (ETS) in New Zealand: each tonne of CO_2 is assigned a value of $NZ25/tonne ($12.5/tonne for participants other than forestry) and needs to be added to operating costs and/or passed on to downstream customers This may be the turning point for some companies to start looking at alternative ways to eliminate or reduce their carbon emissions.

Private Industry CCS Policies

Some New Zealand operating companies have CCS policies but it was outside the study scope to source and review these publicly, if available publicly. For instance Solid Energy represented in the NZCSS Partnership has publicly been very supportive of CCS and states that taking full responsibility for greenhouse gas emissions is a key consideration in all its developments.

6. CASE STUDIES

Two case studies were developed during Phase 2 of this study. It was deemed important by the NZCCS Partnership and the TW-lead consortium that these case studies be sufficiently generic to illustrate future issues for the whole of New Zealand and not just a particular or select industry. With this in mind the six selection criteria were listed, based on the objectives of this study and the results from the Phase 1 review work. These criteria were confirmed with the NZCCS Partnership members during the Wellington meeting on 31 March 2010.

The final selection criteria agreed to consider:

- Industry sector selection;
- Process technology and age of the plant; and
- Location or region.

The stakeholder and environmental and legal/legislative implications were reviewed against what had been completed in the Phase 1 review work and updated to suit.

6.1 Case 1: Taranaki - Retrofit Plant

This case was loosely based on what a CCS facility may be made up of in a region like Taranaki, with existing multiple major CO_2 emitters but also within relatively close proximity to potential future carbon sinks e.g. depleted reservoirs.

Table 6.1: Assumptions for Case Study 1

CRITERIA	DESCRIPTION
Industry	1 Million tonnes per year, assumed existing Gas-Fired Power Plant (natural gas combined cycle, NGCC) Addition of 300kT/y from gas processing or ammonia CO_2 emissions (with existing process CO_2 treatment).
Technology	Existing Plant(s): 1) power station retrofit and minor modification of gas processing or ammonia CO_2 emissions (with process CO_2 treatment). Injection wellsite conditioning including compression and heating systems.
Location	Taranaki, North Island (assumed storage at Kahili site), potential to use existing easements. 30km via 12” underground pipeline from power station to injection site. 30km tie-in via 6” underground pipeline to second upstream plant.
Social/Community	Low Population, High-medium cultural significance, Significant heavy industry (e.g. Oil and Gas)
Environmental	Low environmental impact e.g. existing industry & pipeline easements.
Legislative (assumed)	Current New Zealand Legislation

The case study is designed to capture not just one point source but also demonstrate the likely commercial implications if multiple users were feeding the same carbon sink. The major assumption with this case study is the "additional" plant requires very minimal process changes to supply CO_2 emitted at pressure i.e. negligible cost.

6.2 Case 2: Southland - New Plant

Case 2 was loosely based on what a CCS facility may be made up of in the region of Southland, with one new large major CO_2 emitting or processing facility and little or no existing infrastructure e.g. easements or developed reservoirs.

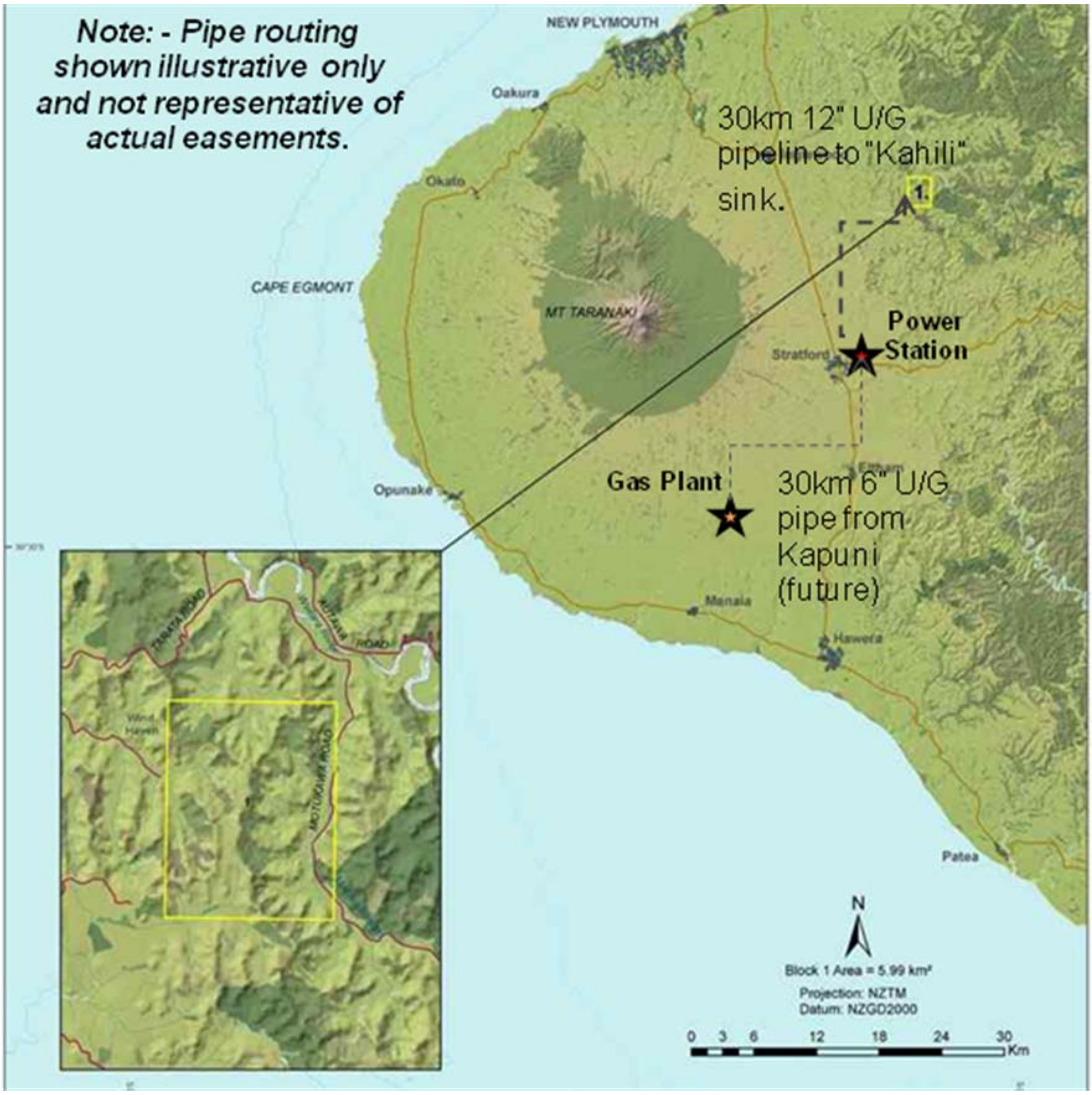
Table 6.2: Assumptions for Case Study 2

CRITERIA	DESCRIPTION
Industry	4 Million tonnes per year from assumed future lignite conversion process(es).
Technology	New processing plant(s) (note: - case study estimates based on lignite to fertiliser process)
Location	Southland, South Island 100km 18" underground pipeline to storage site in Winton basin (assumed suitable sub-surface formations available).
Social/Community	Low Population, Medium-Low cultural significance, Less heavy industry
Environmental	Higher environmental impact e.g. no existing infrastructure e.g. no existing pipeline easements.
Legislative (assumed)	Current New Zealand Legislation

6.3 Case Study Illustration

Illustrations of what these case studies could be made up of are shown in Figures 6.3 and 6.4 below.[6]

Figure 6.3: Taranaki - Case Study 1



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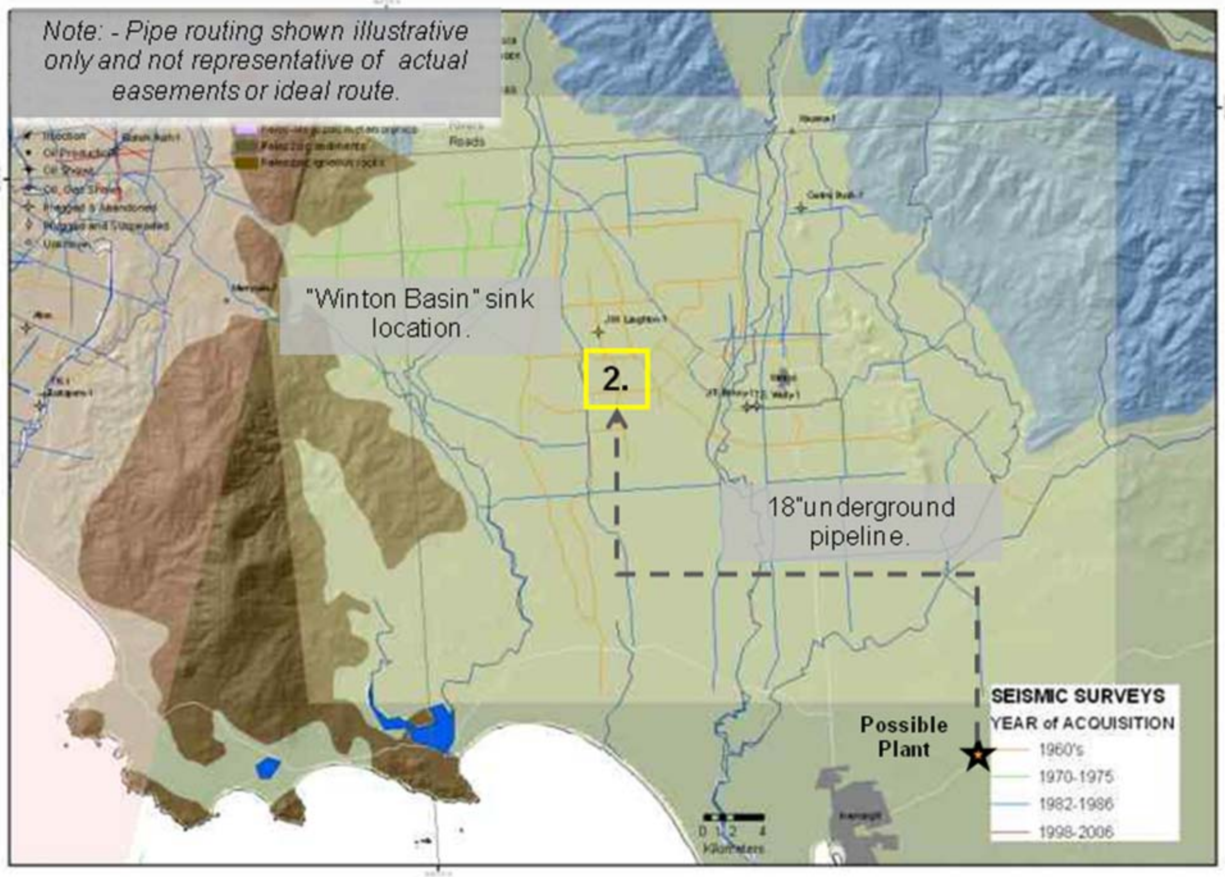
[6] *These illustrations (Figures 6.3 and 6.4) are for pictorial information only to assist understanding of the Case studies presented and do not reflect any future CCS developments current or proposed for the future.*

Figure 6.4: Southland – Case Study 2



7. STUDY FINDINGS

In this section the broader impacts of commercial scale CCS in New Zealand are identified. This is based on the two case studies selected and the specific findings relating to carbon capture, transport and storage. In addition, the case studies considered the commercial, environmental, legal/legislative and social/stakeholder impacts associated with deploying a commercial scale CCS facility. From this discussion the gaps, barriers and opportunities were developed. These are contained in Section 8.

7.1 NZ Carbon Capture [7]

Major Point Sources

As mentioned in section 5.3, most of the existing point sources for CO_2 capture in New Zealand are in the North Island and include power stations i.e. near Huntly, Auckland and Stratford and numerous process plants in Taranaki, and Northland, (see earlier Figure 5.2). The largest South Island point source, the Aluminium Smelter, near Bluff, was discounted technically because the low concentration of the stack emissions renders any current capture technology unviable.

Power Stations

Major carbon emitting power stations in New Zealand are mainly NGCC, the example technology set for Case Study 1. The most viable option for near-term retrofitting of a facility to these existing units is post-combustion capture technology, as this is the most commercially proven technology for this type of process plant.

The obvious advantage for this type of CCS retrofit is the reduction in CO_2 emissions from the combustions gases discharged via the flue stack(s) and post-combustion capture technologies have been applied commercially in similar applications but not necessarily to the same scale.

However, retrofitting of an existing NGCC power station comes with the following disadvantages:

- New major capital equipment is required including: absorber and regenerator, dehydration and compression equipment, as well as associated utilities;
- Low pressure steam is diverted (from the low pressure steam turbine) to the solvent regeneration, reducing a) the efficiency of the steam cycle and b) the net amount of electricity generated from the plant.

For instance in case study 1, a “Stratford” sized NGCC power station (emitting up to 1 million tonnes per annum of CO_2) could be retrofitted with such equipment at the cost of around NZ$318million (+/-40%). This value excludes the cost of installing pipelines, associated block valve stations to the carbon storage area, carbon storage costs, and any associated commissioning and contingency costs.

Reductions in the power station generation efficiency are shown by the increasing auxiliary loads and increased fuel gas consumption (see Table 7.1) and also by the reductions in the electricity generated by the lowering of Net Power (MWe) (also shown in Table 7.1). These changes in net power output and generation efficiency equate to increased operating costs as well as decreased net power available for sales.

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[7] Refer also to Attachments 1 and 2 for further details around the capture processes and development of the two cases, by WorleyParsons, Reading.

Table 7.1: Power Station Performance - Pre & Post Capture [8]

	Load Existing	Load After	Load Change	NZ$/day	% Change
Fuel Gas Increase	2390 GJ/h	3019 GJ/h	629GJ/h	-$90,760	26%
Net Power Lost	369.48MW	356.99MW	12.5MW	-$65,950	3%
			Sub-total (losses)	***-$156,500***	
ETS (CO_2)	142T/h	39T/h	-103T/h	$61,800	72%
			Total (Difference)	***-$94,700***	

Clearly, case study 1 that illustrates retrofitting an existing NGCC power station with CCS is unlikely to be economically feasible because of the very high capital outlay and unfavourable economics (due to increased operating costs) under the current carbon prices. Furthermore, breakeven costs resulting from any ETS savings to offset the operating losses would not occur until the price of carbon reaches above NZ$63/tonne.

For a power station the size of Huntly the size of the capture equipment would be much larger than any current commercial application demonstrated in case study 1 (well over 4 times). As a result; the capital cost is also likely to be higher (although not four times the cost). The Huntly power station has several fuel sources (coal and gas) and is made up of a number of generating plants, so there will be a number of different capture technologies required to support CO_2 capture from this site (increasing the CAPEX further). While a more complex power station like Huntly was not completed in a case study it should be noted that this power station cannot be treated as a direct scale up from case study 1.

Process Industries

New Zealand has two types of process industries that are potentially suitable for retrofitting of CCS:

- The so-called “low hanging fruit” which have some existing CO_2 separation and treatment; and
- Those that have large emissions.

The first group of industrial processes (such as Kapuni natural gas processing, Kapuni urea plant and Marsden Point Refinery hydrogen production) currently have pre-combustion CO_2 separation steps as an integral requirement of the process. As a result, CO_2 drying and compression equipment is already present within the facilities. Retrofitting of a CCS facility to these processes is advantageous in that:

- It is much simpler and cheaper as the capture equipment already exists,
- The CO_2 capture technologies have already been demonstrated on an industrial scale in these applications, and
- It involves only assessment and possible modification/upgrade of the existing equipment for adequacy to meet the carbon transport or pipeline specification.

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[8] Note: - The changes in operating costs and based on assumed unit rates and include - fuel gas = $6NZ/GJ, net power (sales) = 22c/kWh, ETS = $NZ25/$CO_2$tonne, and are modelled on a later model power station with net efficiency (LHV) reducing from 55.7% to 42.6%. In reality, older power stations (e.g. existing New Zealand models) would be less efficient again.

Case study 1 was also expanded to include manifolding of point sources. This is an option where there are several industries with significant CO_2 emissions but not enough to justify solo investment into a carbon sink(s). For the purposes of case study 1, it was assumed this “manifolded” technology was similar to that for the Kapuni gas treatment or urea plants, and for the cost estimating the additional plant emissions did not require any further modification so the waste CO_2 could be directly fed into a new CCS Pipeline (see details in Transport section, to follow). [9]

The second type of industrial process is more complex and requires consideration of the individual process stages (and resulting emissions) as well as identification of suitable capture technologies. While the total CO_2 emissions are reported for each of these process sites, it may not be possible to capture all of the CO_2 emitted, so any future CCS facility may only collect some of the process emissions. Retrofitting of these existing process facilities is similar to the retrofit of a power station and is likely to come with the following disadvantages:

- New major capital equipment is required as well as associated utilities;
- Complex venting and flaring systems may require separate capture technologies and/or equipment increasing capital expenditure;
- It may not be economical to capture all of the CO_2 emissions, which may further reduce any economic returns (i.e. reduction on ETS prices);
- While the capture technologies have been developed, these have not been demonstrated on a commercial scale.

The priority for New Zealand’s existing process and power industry operators would be to focus on attaining confidence in the monitoring and accuracy of their current operating costs. From there an operator can accurately better determine whether investing in CCS is relevant at this time. This approach is, of course, dependent on the impact of the NZ ETS on each particular operating facility.

New Industry

There are future opportunities for new process industries to include a capture system into their process. This would result in these proposed projects avoiding an expensive retrofit in the future and ensuring minimal impacts on the environment (with respect to CO_2 emissions) into the atmosphere.

Case study 2 illustrates an example of how this might work, focusing on a future lignite processing facility in the Southland region. Obviously this is a much simpler approach as the costs of the CO_2 collection is included in any initial capital investment and is not additional capital (justified independently to the main plant). Further costs would therefore be minimal and include only the pipelines and any additional equipment to ensure the CO_2 can be transported and is supercritical when injecting. The costs of carbon capture for this case study are estimated at $NZ136million +/- 40% (excluding any transport pipework or block valve stations, carbon storage costs, and associated commissioning and contingency costs).

Refer to Table 7.7 in Section 7.4 for a full break down of the capital expenditure for both case studies.

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[9] *The assumption that neither an existing urea plant nor gas treatment plant would need significant modification is an optimistic one. Each process plant would need to have a detailed engineering review completed before it could be determined if this was indeed the case. Significant additional costs (i.e. >$NZ1,000,000) could be added to Table 7.1, above if additional compression was required in these circumstances.*

Table 7.2: New Processing Facility [10]

	Load Existing	Load Change	$NZ/day	% Change
Electricity Increase	0MW	22.5MW	-$43,100	n.a.
		Sub-total (losses)	***-$43,100***	
ETS (CO_2)	456T/h	-456T/h	$273,970	100%
		Total (Difference)	***$230,770***	

The economics on this investment are obviously more positive as it recovers lost operating costs (see Table 7.2, above). It should be noted that the scale of this case study surpasses any current international CCS projects e.g. the Gorgon project in Western Australia includes a CCS facility capturing 3.5 to 4 million tonnes of CO_2.

7.2 NZ Carbon Transport

As mentioned in Section 5, New Zealand has existing onshore and offshore high pressure gas pipelines that could potentially be used for CCS. These are only located in the North Island and are already fully utilised for electricity generation, feedstock and/or fuel gas supply to industrial process and utility plants. It is not envisaged these pipelines will become available or accessible for CCS.

However, if the status of these existing pipelines did change, and could be adequately isolated from the main gas networks, then reusing these pipelines for a future CCS facility would require additional compression systems (adding further cost to any CCS development). The design of these existing so-called “high pressure” gas pipelines is well below expected CCS injection pressures (up to an estimated 300barg). Consequently, these pipelines have insufficient wall thickness to ever operate significantly above current conditions. As an example, the current operating pressure of the Maui pipeline is 42-48barg (Anonymous_g 2010).

The additional compression stages would be required to transport the captured CO_2, then with another compression stage to meet the injection pressure requirements at the carbon storage wellsite. Alternatively if the pipelines were fully rated for CCS, only one compressor station may be required for both carbon transport and injection (e.g. case study 2 in this report).

Other factors of these existing gas pipelines, which may further reduce the operating pressures or pipeline suitability for CCS, include: length of service, condition, specification or metallurgy. Given the timescale involved for further investigations of this magnitude and the likelihood of these becoming available, for both case studies it was assumed any carbon transport would be provided by new pipelines. That said, case study 1 does demonstrate the impacts of staged compression (similar to the case if existing pipelines were to be used) and includes a two stage compression process: [11]

- 1.4 barg to ~190barg at the point source (allowing for a 10barg pressure drop between the point source and injection sites,
- 180 barg to ~240-290barg at the injection wellsite.

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[10] The changes in operating costs and based on assumed unit rates and include - net power (high user) = 8c/kWh, ETS = $NZ25/$CO_2$tonne,

[11] The injection pressure into the case study 1 field (assumed to be Kahili, in the Taranaki region) is also much higher than those expected in other regions e.g. Southland’s Winton Basin (carbon storage basis for case study 2). [Schlumberger]

The reason behind this staged approach to compression for case study 1 was based around the restrictions already in Australia (these differ from high pressure gas pipeline operation) and limit CO_2 pipeline pressures to 160barg (e.g. Otway). The slight increase in pipeline pressure (shown in case study 1) does not necessarily mean an increase in pipe specification to meet the higher pressure, so the Australian carbon transport pipeline restrictions may provide an extra level of design protection.

If New Zealand were to adopt a similar approach to Australia, with pipeline pressure restrictions it is recommended to review the design and operations of the carbon transport as a whole system, avoiding potentially unnecessary limitation of pipeline operating and design conditions. , In comparison, the oil and gas industry has no such limitations, and transports more volatile fluids than $CO_{2,}$ some at higher pressures through plant and pipelines.

While there is the possibility of using intermediate compressor stations to transport any captured CO_2 at lower pressures to the injection wellsite, potentially utilising New Zealand's existing high pressure gas pipelines, this is a more expensive approach to CCS because of the likely increased number of compressor stations required (more than the two given in case study 1). It also includes additional risks; confirming existing pipelines condition and ensuring current pipelines codes are met for the new service e.g. current pipeline codes and standards.

Case study 2 is a simpler design and has been completed on the basis that the expected injection pressures (at the injection site) can be delivered from the point source location (some 100km distance). This approach comes with the following advantages:

- Reduced infrastructure (e.g. compression) at the injection site or along the pipeline route
- Reduced utilities costs (e.g. electricity) and
- Reduced environmental & social impacts (note: - most of the carbon transport system will be below ground level, so apart from the initial installation, there is less impact by reducing above ground infrastructure).

Table 7.3 summarises the capital costs for the carbon transport of the two case studies[12]. For the overall costs summaries, see Table 7.7 in section 7.4.

Table 7.3: Pipeline Capital Costs (Carbon Transport)

Case Study	Description	Installed Costs ($NZ)
1: Taranaki	30km 12" underground CS pipe (Schedule 80)	$31.99 million
	30km 6" underground CS pipe (Schedule 80)	$17.84 million
	Total CAPEX – Case 1	**$49.83 million**
1: Taranaki	Operating Costs (Electricity at wellsites & plant)	*increase*
2: Southland	100km 18" underground CS pipe (Schedule 80)	$184.00 million
	Total – Case 2	**$184.00 million**
2: Southland	Operating Costs (at the point source plant)	*minimal increase*

Perhaps, the biggest argument against utilising existing gas infrastructure pipelines to transport CO_2 is that these pipelines are integral to New Zealand's current domestic gas and electricity supply to the

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[12] These capital costs are high level (+/-40%) and include allowances for the required block valve stations (as per New Zealand pipeline specifications) and also construction. These costs differ from section 7.4 (that follows) in that they do not include contingency which is typically 20% for this level of estimate.

Auckland, Waikato and other North Island regions. These power stations and reticulated gas supplies would need to be replaced with alternative technologies before the existing gas pipelines could be utilised in any form. Other major gas users around the North Island would also need alternative fuel or electricity supply.

7.3 NZ Carbon Storage [13]

Storage Options

There are four factors that need to be addressed when assessing carbon storage sites:

- Capacity – the amount of CO_2 that can safely be stored;
- Injectivity – the ease with which the CO_2 can be injected;
- Containment – the ability to store CO_2 safely and permanently; and
- Other External Factors – e.g. environment, infrastructure, regulation, and public opinion.

Storage sites evolve over time and there are different mechanisms apparent that “hold” any liquid or gaseous formations. For instance, oil and gas fields demonstrate storage durations of millions of years even in sensitive, seismic zones. Further, there are no technical or geological reasons to indicate that CO_2 cannot be safely stored in a similar manner and/or areas.

In New Zealand, storage of CO_2 would be in geological formations e.g. depleted oil or gas fields or deep saline formations. As noted earlier these are not huge caverns but instead “solid rocks’ that have some porosity and therefore behave like a sponge. Enhanced oil and gas recovery does not compliment carbon storage activities (see Table 5.6 for reasons) and the approach for New Zealand case studies was to review existing information and make assumptions on missing information.

Overall, the Taranaki basin, Kahili (case study 1) is deeper so requires higher injection temperatures and pressures than the Winton basin, Southland. Assumptions were made around the potential reservoirs’ pore pressures and injection pressures (to ensure a safe operating margin before rock fracture). Similarly for wellhead temperatures and reservoir temperatures to prevent thermal shock that would also compromise the formation strength. Table 7.4 provides an overview of the formation parameters found/assumed for the respective case studies and further information is documented in Attachment 3 of this report.

A further point to note from case study 1 is the Kahili field is not large enough for the full volume of CO_2 requiring storage over the assumed CCS operating lifetime of 30 years. Access to adjacent permits would be required in this instance (which may not be available) or given the complexity of NZ formation may result in interplay with other non-CCS operations.

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[13] Refer also to Attachment 3 for further details around carbon storage and development of the two case studies by (Ingram 2010).

Table 7.4: Case Study Formations

	Case Study 1	Case Study 2
Wellhead Temperature	116degC	76degC
Wellhead Pressure	242-293barg	153-186barg
Formation Depth	2750m	1750m
Thickness	30m	50m
Porosity	50md	25md
Permeability	0.15v/v (volume/volume)	0.11v/v
Volume CO_2	1.3 million tonnes/year	4 million tonnes/year
Life time (operating)	30 years	30 years
Injector Sites	5	24

The reservoir geology determines the design criteria for the capture and transport systems, so Table 7.4 also shows that case study 1 obviously requires much higher injection pressures and consequently the specification for the above ground infrastructure to support this, than case study 2.

Table 7.5 below shows the associated storage costs with each case study. Capital costs include the costs associated with finding, appraising, and developing exploration storage wells. Operating costs cover the ongoing costs e.g. the consumables (fuel, electricity, water), insurances and maintenance. Clearly, exploration and appraisal drilling for carbon storage is not a cheap process. It also should be noted that the assumptions behind these figures are optimistic with respect to development success, so there are no “lost development funds” built into the costs for these case studies. In reality the success rate may be vastly different to the figures presented here, and could easily double.

Table 7.5: Case Study Costs

	Case Study 1	Case Study 2
CAPEX (nominal 30years)	$AU112 million	$AU392 million
OPEX (nominal 30 years)	$AU113 million	$AU388 million

The next section (section 7.4) includes an overview of all capital and operating costs for the case studies in New Zealand dollars.

Several points were raised in the Global CCS Institute’s Report (McConnell and Matsuda 2009) that is also relevant to the case studies and carbon storage. These are summarised by:

Carbon Storage is the Technical Critical Path

The finding, appraisal and development of a carbon storage site is most likely the technical critical path in any CCS project, given the typical timeframes taken to identify and develop wells e.g. in the oil and gas industry. To reduce the risks (increases to associated costs and project timelines) it is suggested multiple sites need to be appraised, building up a "Portfolio" of storage options, in the event some would not support CCS.

This approach can be completed by industry or involve both industry and the government. The New Zealand government has undertaken some geological mapping work through the CO2CRC and GNS, which is the first stage of data collation for CO_2 storage development. Other governments have developed partnerships or task forces to provide a collaborative and holistic approach to identifying a portfolio of options. This is a possible next step for New Zealand.

Uncertainty around Storage drives entire CCS Projects

Project economics usually require an economic return for development or implementation. In the case of carbon storage the return needs to be greater than the "finding" and development costs so the private sector has an incentive. Currently, there is uncertainty in New Zealand around the price of carbon, the long-term implications of the NZ ETS (and the legal and property rights for CO_2 storage) that any financial incentive to start carbon storage investigations by the private sector is overshadowed. As a result, industry is waiting on government direction to resolve these issues. This only provides further justification for a coordinated approach for targeted carbon storage exploration.

Figure 7.6 (McConnell and Matsuda 2009), illustrates a carbon storage appraisal process that would need to be undertaken to identify transport and storage sites at a particular location. It shows a typical timeframe of 10 years of exploration and development before a carbon storage reservoir becomes operational. Obviously this could potentially be accelerated through various methods.

The first stage of site selection would cover a desktop study on a range of prospective sites using publicly available geological data to ascertain storage fundamentals such as a suitable seal, first pass porosity and permeability data that will allow a portfolio of perhaps 6-8 "plays" to be earmarked as potential sites warranting further investigation. This could take up to 12 months with a full technical team of geologists and reservoir modellers at a cost of approximately $1-2 million, depending on the quality of the data initially available.

From this point, assuming property rights and funding can be accessed, there would likely be new seismic studies done to determine where to drill the wells to test, confirm prospective sites for injection potential and to determine site capacities (bearing in mind that it will be injection rates that will determine the commerciality of a site operation going forward). Fundamentally, however, the geology will drive the storage site selection and the site will drive the commerciality of large scale, integrated CCS projects. In general, "finding" costs can vary from $25 million in the ideal case to $150 million or more depending on the geology. Thus, it is evident that as many as 4-5 years of expenditure may be incurred prior to technical and regulatory uncertainty having been reduced around a potential storage site that would allow FID and full field development plans to be executed.

Applying this to the NZ case studies, the finding costs for the South Island study could well be significantly larger due to the relatively sparse public data already available. There have been few seismic lines shot over the Winton Basin and only 2 wells drilled. Thus, the exploration program would be aimed at covering data gaps on the fundamental geological characteristics, similar to the presence of regional seal prior to any Final Investment Decision (FID) being made on a full CCS project.

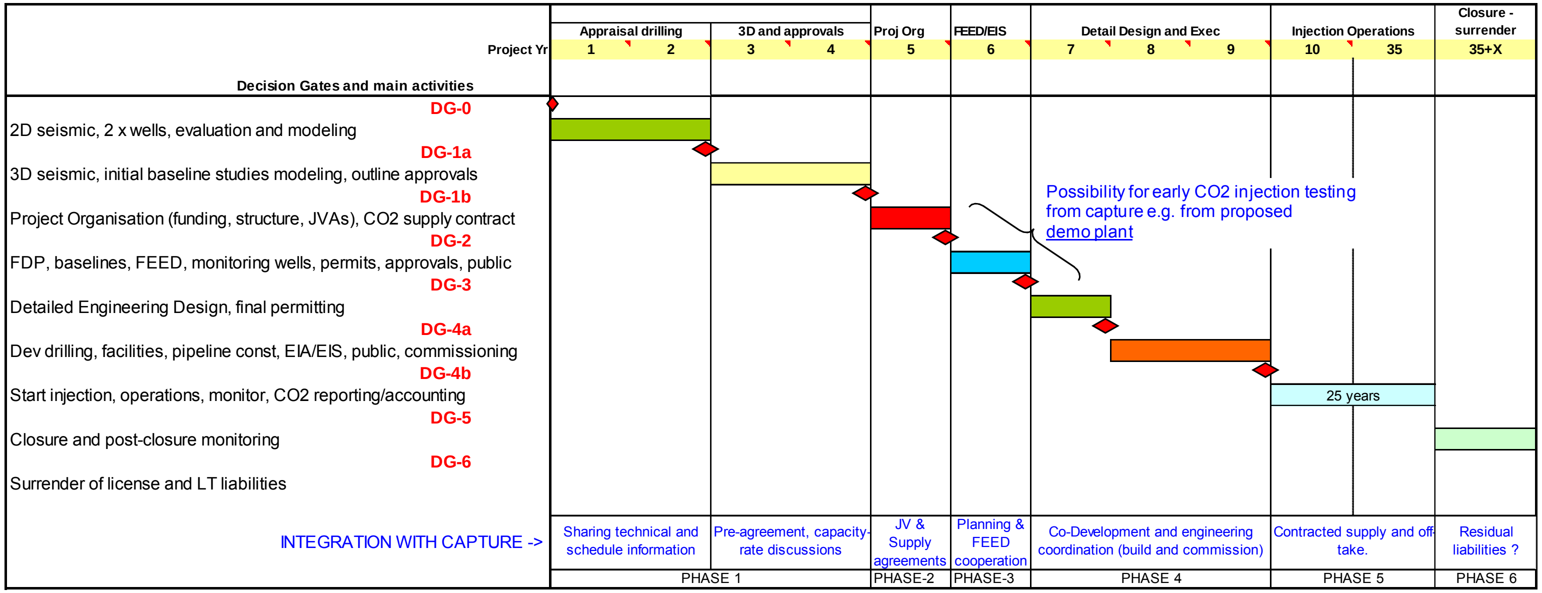
This is would be carried out using a stage-gated approach (refer to that described earlier in Section 3 and also shown in Figure 7.6) and should have a number of gates to proceed through before each tranch of funding is approved.

Therefore, the assumption of plant start up in 2016 is optimistic and would assume that the exploration work in comparatively unexplored regions (like the Winton Basin in case study 2) are entirely successful at proving up and developing a suitable play close to the plant. The ‘finding costs’ are most likely underestimated if anything.

Relatively speaking, New Zealand on the whole would be at decision gate 0, where there is still a fundamental decision on whether CCS projects will be undertaken in the country.

Figure 7.6 Conceptual site(s) exploration & appraisal study schedule

GENERIC TRANSPORT & STORAGE - SCHEDULE FOR DELIVERY



DG-0 : Ready to proceed to Phase 1 ? All Conditions Precedent met (tenements & funding) ?

DG-1a: Ready to progress to 3D & feas ? The evaluation of drilling data supports containment, injectivity and capacity forecasts ?

DG-1b: Ready to progress to Project Organisation, Phase 2. Evaluation of 3D seismic, initial EIA, pipeline feasibility reports support full development project - outline consents in place.

DG-2 : Ready to progress to FEED, FDP & full EIA. Commercial agreements in place (funding, financing, JV and CO2 supply etc).

DG-3 : Ready to progress to Detailed Engineering Design. FDP, pipeline FEED, environmental baselines, public confidence and permits all in place.

DG-4a: Ready for FID ? Detailed Engineering Design complete ready to start execution.

DG-4b: Ready to start Injection Operations ? Commissioning complete, operation plans in place, all permits ready, M&V scheme in place.

DG-5 : Ready to cease injection ? Site license fulfilled, licensed storage capacity met. Approved plan for post-closure monitoring.

DG-6 : Ready to surrender license ? Monitoring and modeling confirms little residual CO2 movement or risk.

Source: GCCSI Synthesis Report, 2009

7.4 Capital & Operating Costs

Table 7.7 below summarises the capital costs of the CCS for the two case studies, assuming a 30 year lifetime CCS project. These estimates are high level estimates (+/-40%) and are based on the assumption that there is a viable sink available and amenable to CCS development.

Table 7.7: Case Study CAPEX [14]

CASE STUDY 1		**$NZ (millions)**
Carbon Capture (via WP &TW)		**$318.09**
MEA CO_2 Removal Package		$198.52
Auxillary Systems	*steam generation & heat integration systems*	$47.03
Compression Package	*includes 2 by 16MW multistage compressors (8)*	$69.62
Wellsite Equipment		$2.92
Carbon Transport (via TW)		**$49.83**
Kapuni to Stratford Pipeline	*30km of 6" Schedule 80 CS Pipeline*	$17.84
Stratford to Kahili Pipeline	*30km of 12" Schedule 80 CS Pipeline*	$31.99
Carbon Storage (via Schlumberger, including contingency)		**$136.59**
5 Vertical Injection Wells (30 year life)		$136.59
Sub-total - Case Study 1 (including $18million commissioning)		**$522.51**
Contingency (20%)		***$40.88***
Total Capital - Case Study 1		**$563.39**
CASE STUDY 2		**$NZ (millions)**
Carbon Capture (via WP &TW)		**$136.16**
Auxillary Systems	*includes utilities & other infrastructure*	$7.66
Compression Package	*includes 2 by 22.5MW multistage compressors (8)*	$128.50
Wellsite Equipment		$ -
Carbon Transport (via TW)		**$184.00**
Morton Mains to Winton Basin Pipeline	*100km of 18" Schedule 80 CS*	$184.00
Carbon Storage (via Schlumberger, including contingency)		**$478.05**
24 Vertical Injection Wells (30 year life)		$478.05
Sub-total - Case Study 2 (including $10million commissioning)		**$808.21**
Contingency (20%)		***$134.41***
Total Capital - Case Study 2		**$942.62**

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[14] Conversion from the storage costs provided (refer attachment 3) to NZ dollars was calculated at $0.82AU/$NZ. The Schlumberger storage costs shown in Tables 7.7 and 7.8 were developed from detailed reservoir modelling, based on assumptions from industry experience. A detailed breakdown of the working behind these costs is not relevant to the objectives of this study.

Table 7.7 illustrates the order of magnitude of the total carbon capture, transport and storage costs for a large CO_2 emitting, existing power station process in NZ (case study 1) and also the likely financial impact on a large, future project that includes CCS (case study 2). To put these figures in more context, Table 7.8 below provides an illustration of potential overall CCS operating costs with such a retrofit (case study 1) or new plant (case study 2).

Table 7.8: Summary of Operating Costs for Case Studies 1 and 2 [15]

	Case Study 1	**Case Study 2**
Capture/Transport	($NZ millions)	($NZ millions)
Operations (1% of CAPEX) assumed annual	$3.86	$3.30
Maintenance (3% of CAPEX) assumed annual	$11.58	$9.90
Total 30 Year Lifetime	**$463.09**	**$396.20**
Storage		
Operations & Maintenance (30 Year Lifetime)	**$137.80**	**$473.17**

7.5 Legal & Legislation

New Zealand has not yet enacted a complete legislation framework governing the capture, transport and storage of CO_2. Instead, the study focus has been to review the existing legislative frameworks which may be applicable to CCS activities In New Zealand. This approach did not change with the development of the case studies. Overall, it was found the existing legal frameworks are either not applicable to CCS activities or address only limited aspects of the CCS project cycle.

This section is taken from a report by Baker & McKenzie, Australia on New Zealand's legal processes and systems with respect to CCS developments (see reference in section 9 (Beatty and Wong 2010)).

NZ Legislation Overview

Table 7.9 below illustrates the level of support the current New Zealand legislation and regulations has for CCS developments. The applicability of each Act or Regulation is indicated by the inclusion or exclusion of a symbol at each step. More importantly the detail on whether each Act or Regulation supports or may impede future CCS development is shown by the type of symbol.

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[15] Conversion from the costs in attachment 3 to NZ dollars was calculated at $0.82AU/$NZ.

Table 7.9 Overview of the Suitability of Existing NZ Legislation to CCS [16]

Current NZ Statutes	Exploration for CO_2 Site	Capture of CO_2	Transport of CO_2	Injection of CO_2	Closure, Storage -long term
Crown Minerals Act 1991	O			O	O
CM Petroleum Regs 2007				O	O
Continental Shelf Act 1964	O			O	O
Foreshore & Seabed Act 2004 *(NZ territorial waters)*	O			O	
Resource Management Act 1991		Y	Y	Y	X
RMA Amendment 2009		Y	Y	Y	Y
Building Act 2004 *(Construction of buildings)*		Y		Y	
Gas Act 1992/Gas Regulations 1993 *(Fuel gas transport)*			O		
HSE Pipeline Regulations 1999 *(Pipeline construction)*			Y		
Submarine Cables & Pipelines Protection Act 1996			Y		
HSNO Act 1996/ERMA *(Transport by rail/road)*			O		
HS(Compressed Gases) Reg 2004 *(Transport by rail/road)*			X		
Climate Change Response Act 2008 *(CCS Projects)**	O	O			

Table 7.9 Key:
Impacts Act/Reg = Y **Gaps** In Act/Reg = O **Barriers** In Act/Reg = X

Resource Management Act

From Table 7.9, the Resource Management Act 1991 (RMA) appears to be the most relevant to future New Zealand CCS activities, potentially regulating multiple stages of the CCS project cycle (from post-exploration covering CCS development and operation). The RMA is a comprehensive environmental code that applies broadly to all the environmental effects of any activity, governing the use, development and management of resources. For NZ CCS projects, the RMA is currently relevant at each of these stages because CO_2 is likely to be classed as a contaminant under the RMA.

An opportunity for a future CCS development may be to utilise the RMA is the Resource Management (Simplifying and Streamlining) Amendment Act 2009. Section 145 of the amended RMA provides that if a project is of national significance, an application for Resource Consent may be lodged with the EPA (Environmental Protection Authority) rather than the relevant council. A CCS project could be classified

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[16] : There's a gap in the Climate Change Act (as it's currently written) that does not include CCS projects as a specified "removal" activity under the ETS, nor state when CCS projects will be included as such.

as having national significance and this amendment may result in a faster, more efficient application process and will provide some certainty around the timeframe taken to process the application.

The gaps or barriers against CCS developments with regard to applying the RMA are around injection of CO_2 into geological structures, and the long-term monitoring of and liability for sequestered CO_2. In particular:

- The RMA imposes a duty on “every person” to avoid, remedy or mitigate any adverse effect on the environment (regardless of consent conditions),
- Current consent durations are limited to 35 years, and
- Any previously stored CO_2 leakage (outside of a current valid resource consent) is likely to be liable for discharging a contaminant and subject to imprisonment or fines.

Storage of CO_2 would likely change the physical, chemical or biological condition of the receiving water or land via a variety of mechanisms (the least would be increased sub-surface pressure). The gaps and barriers for CCS injection and long-term storage under the current RMA framework would need to be remedied before a potential CCS project could be sanctioned in a way that would win public acceptance.

Acts Covering Exploration

New Zealand exploration and mining rights for minerals and resources are governed by the Crown Minerals Act (CMA) and the Continental Shelf Act. These Acts cover land and offshore to within NZ’s territorial waters (12 nautical miles) and from 12 to 200 nautical miles, respectively.

The two Acts relate to the extraction of minerals and petroleum, and in their current form are of limited application to CCS projects, i.e. the injection of CO_2 or any gas or liquid into a reservoir. There are also some property access clarifications required between the CMA and the *Foreshore and Seabed Act 2004*, as to access where the foreshore or seabed is subject to customary right.

Acts Covering Carbon Transport

Following the legal review of New Zealand legislation, there are more barriers against transportation of CO_2 via road or rail (through Hazardous Substances and Noxious Organisms Act (HSNO) and Hazardous Substances Compressed Gases Regulations) to overcome than there are on the gaps in the gas pipelines regulations and acts.

The Gas Act does not currently include CO_2 as a gas because it covers “fuel gases” (methane) only but this Act does govern gas pipeline maintenance and operating activities e.g. inspection, testing, safety etc. This definition gap in the Gas Act would need to be closed before future CCS projects could be furthered.

7.6 Environmental Impacts

Overall, impacts of a future CCS development did not raise major concerns or show-stoppers with respect to environmental planning and application under the RMA. Aside from the concerns (mentioned in section 7.5, above) around some of the details in the RMA e.g. timeframes for projects consenting, there was little that could not be worked through as part of the regular planning processes.

Development of the two case studies confirmed initial concerns regarding different approaches for each region and suggested some possible conservatism (which may translate into additional time to process) for new developments. It could be suggested that as part of the next phase of work some structure is put in place at national government level to assist with processing the application of future CCS developments.

Planning & RMA

The regional and district plans that apply in the area for carbon capture and storage activities will determine whether the activities will require resource consent. There is no national consistency in terms of how NZ regional district plans assess and classify activities, and as a result CCS may be treated more simply or favourably depending on the region or district where it is located. However, there also is no precedent set for CCS activities, even though the technologies that would be employed for carbon capture, transport and storage are already well developed and in commercial applications in NZ. As a result the approach may be more cautious than if there had already had been significant experience with a number of existing operations.

The RMA was identified as a likely foundation Act for any future environmental planning of CCS Projects and it contains a broad definition of the environment: Not only the natural environment but people, amenities and communities. Any application must be accompanied by an Assessment of Environmental Effects (AEE) and under the RMA there are a number of different processing options that could be considered for a CCS project.

The RMA also includes a particular regard for the effects of climate change when exercising functions and powers of the Act. For the time being, this has been understood to relate to consideration of the effects of climate change on activities and not the effects of activities on climate change. This interpretation may change and should be considered for a future CCS project.

Environment, Health & Safety

This section is a summary of the report completed by MWH, New Zealand (see referenced in section 9 for further details on the specifics of the RMA with respect to environmental planning and detailed analysis of district plan implications for the two case studies) (Burkitt, Hunter et al. 2010).

The summary of the major environmental, health & safety (EHS) requirements associated with any future development of a CCS project in New Zealand is listed below:

- Detailed site specific risk assessment of all the EHS aspects of each particular project proposed.
- Detailed surface and sub-surface characterisation must be completed, using well-established geophysical and simulation techniques. This will define those potential CCS storage sites that are protective of groundwater resources, environmentally sensitive parameters and human health and safety.
- Development of measurement, monitoring and verification guidelines needed to track the performance of a CCS activity; from baselining a CCS site through to operation (injection), then during the post operating phase.
- Environmental data must be collected to assess: CO_2 leakage, displacement of formation water from the storage reservoir into aquifers, and other potential leakage towards the surface.
- Operational monitoring will also be essential to control the injection operations and prevent loss of integrity in the cap-rocks and leakage barriers.
- Assessments of the risks associated with specific CO_2 impurities may also be required.

In all, sound site selection will ensure the EHS concerns associated with CCS can be properly mitigated. Site selection should be based on available sub-surface information, development of monitoring and verification program, expansion of the regulatory system to include CCS activities, and appropriate mitigation to stop or control any releases (if these arise). A national guideline for assessing CCS applications (mentioned in previous sections) would also assist future environmental planning –these technologies are not new to NZ, only the application to CCS.

7.7 Social Impacts

Preliminary results from the interview process competed by CSIRO confirmed there may be a number of social perception and social issues that may adversely impact the development of CCS in New Zealand. These include:

- The low levels of knowledge regarding CCS, its application and relative costs and benefits to the community,
- Lack of certainty regarding the viability of CCS in New Zealand, e.g. seismicity issues and leakage
- Distrust in the current government and industry engagement activities, and
- Opposition to technologies associated with coal mining and burning.

Early and transparent public engagement with a range of stakeholders is critical to educating the scope and ensuring the success of a CCS projects in New Zealand.

Refer also to Attachment 4 for further discussion on the New Zealand stakeholder review, conducted by CSIRO, Australia (Ashworth and Paxton 2010).

8. CCS, WHERE TO FROM HERE?

This section provides an overview of the findings and also suggests areas and topics which should be followed up to start the next steps towards commercialisation of CCS in New Zealand.

8.1 CCS Gaps and Potential Barriers

The study on the commercialisation of CCS in NZ has highlighted the following gaps and potential barriers against implementation of such a facility in New Zealand. Table 8.1 provides a summary of these points discussed earlier in this section.

Table 8.1: NZ CCS Commercial Scale Gaps & Potential Barriers

	GAPS OR POTENTIAL BARRIERS
Carbon Capture	Technically viable Capture Technologies are limited to post-combustion (power) and pre-combustion (gas treatment or hydrogen separation processes) for future CCS facilities, and there are limits to the scale of proven commercial developments. No existing South Island industries viable for carbon capture opportunities, all viable existing opportunities are North Island locations. Not all the carbon dioxide emissions will be captured (either through complicated processes emissions or not technically or commercially viable).
Carbon Transport	Existing high pressure pipelines are not currently available for CCS use (already in use for Oil and Gas Industries and downstream customers, national power supply and domestic gas reticulation). Existing pipelines do not meet the likely operating pressures for CCS. No existing pipeline infrastructure in the South Island. Australian CCS Pipeline Regulations manifestly unworkable.
Carbon Storage	Identification of a suitable carbon sink will require further exploration (and significant capital investment) to confirm e.g. recommend a number (portfolio) of potential sink reserves should be investigated, not one or two, due to potentially low success rate. Existing known reservoir data not publicly available to review for suitability for CCS. Block size is insufficient for CCS under current NZ permit areas and not allocated for CCS activities, only oil and gas exploration. NZ territories not likely to support future CCS due to areas already committed for oil and gas and the much larger areas required for future CCS. Use of these existing permits areas for CCS may impact any adjacent oil and gas exploration or production. Lack of experience and resources in New Zealand, for Oil and Gas related industries outside Taranaki.
Legal/Legislation	Current exploration legislation does not specifically mention the injection of fluids into reservoirs. Barriers in the RMA against injection into environment and long-term storage of contaminants, e.g. CO_2. Definition gaps in Gas Act regarding CO_2 transported via pipelines (only covers fuel gases). Climate Change Act does not currently specify CCS as a removal activity.
Environmental	Detailed modelling and measuring of sub-surface characteristics, to mitigate against any potential leakage. Development of sound monitoring and verification plan to adequately baseline, measure injection operations, and completion/post-closure of CCS storage site.
Social	General lack of public knowledge about CCS, its applications and justification. Some negative perceptions about coal, fossil fuel use and CCS “masking” the exploitation.

8.2 CCS Opportunities

Regardless of the gaps and potential barriers already highlighted, there are still opportunities in New Zealand with respect to future commercial development of CCS and Table 8.2 provides a summary of these.

Table 8.2 NZ CCS Commercial Scale Opportunities

	OPPORTUNITIES
Carbon Capture	NZ has 8 high CO_2 emitting or CO_2 separation industries that could potentially support retrofitting of CCS economically. An approach could be made to these industry sectors and complete combined investigations to confirm CCS is feasible, including confirming existing monitoring practices are robust. 4 of these industries (power stations) are similar to those already supported by commercially developed carbon capture technologies and are likely to have greater potential for economic retrofit of CCS.
Carbon Transport	Review of existing pipeline regulations and related gas acts or development of new legislation to allow provision for pipeline transportation of CO_2. This may include future unlocking of existing pipeline infrastructure and making improvements on other countries carbon transport legislation e.g. Australia.
Carbon Storage	Leverage off the NZ Oil and Gas industry experience and resources e.g. exploration, gas reinjection, underground gas storage. Most Oil and Gas reservoir exploration completed in Taranaki, North Island. Ensure storage facility can hold volumes of CO_2 required for field lifetime required e.g. has held oil and gas for thousands of years.
Legal/Legislation	Resource Management (Simplifying and Streamlining) Amendment Act 2009 could assist consenting processes for CCS projects. RMA could have some role throughout CCS operation. Review or develop other legislation specific to CCS Exploration and Post-Operation Phases (including legal ownership). Develop national framework for assessing CCS projects.
Environmental	Careful site selection may work in CCS facility favour as inconsistencies in district and regional planning may mean future CCS consent requirements are more straight-forward in some locations than others. May be some benefit in including CCS in with a proposed Industrial Project (therefore capitalising on the whole benefits of the project and not isolating CCS).
Social	Early stakeholder education and engagement is critical for the success of a future CCS project. There is an opportunity for government and industry to be proactive in the education of key stakeholders and not reactive after a CCS project becomes in the public domain..

8.3 Next Steps - Framework

There are several directions that the next stages of this study work could proceed to. The gaps and potential barriers noted around legislation and regulations specific to development and operation of a CCS facility in New Zealand will be addressed by national government officials.

For example: Further work needs to cover the gaps and barriers in the current New Zealand legislation before CCS projects can proceed. Immediate concerns include: Climate Change Act – not specifying CCS as a removal activity – the RMA lack of framework for long term CO_2 injection and storage; and the lack of definition around defining CO_2 as a gas that could be transported via pipeline. If a suitable CO_2

storage site was located within 12 nautical miles off New Zealand's shore then the next phase of legislative work would need to address the grey area of property ownership between the Crown Minerals Act and the Foreshore and Seabed Act.

Government representatives were directly involved during the course of the study so these CCS opportunities have not been included in this summary going forward.

The following areas have also been identified as opportunities for further work, these are presented in the order of priority, recommended by the consortium as a result of this study:

- **Social and Stakeholder Education and Engagement** – needs to ensure the New Zealand public is fully aware of what CCS is and the reasons for it to help alleviate some of the negative perceptions. This should include a well-structured and public process that covers all interested stakeholders and deals with the topical concerns e.g. "shaky isles", answer to dirty coal emissions as well as more factual information.
- **Gather & Assess Exploration Data for CCS Sinks** – consortium was unable to secure any private data showing actual reservoir properties during the study. The consortium suggests an overarching review is developed by the New Zealand government, then reviewed and communicated by a special committee including government and industry stakeholders to determine the best locations and a "portfolio" of future CCS storage opportunities to reduce CCS project risks and minimise project timelines.
- **Review of Government's Approach to Permitting for future CCS Activities** – this needs to be re-thought and take into account the much larger areas required for CCS (as opposed to the existing permit areas required for Oil and Gas exploration and production). Potential interplay with any existing exploration or production facilities should also be considered if allocating "future" CCS permit areas. This may discount any area which already has significant oil and gas activities e.g. Taranaki, where a number of high carbon emitting process industries are located.

  Note: This may have a positive spin-off and help reduce uncertainty for potential private sector investors through clarifying the governments long term position for CCS development and the ETS, financial risks associated with investment in CCS may be reduced.
- **Further Industry Sector Investigations** – as a follow-up to the technical content in this report, more specific studies could be investigated in collaboration with representatives from these sectors to ensure current emission monitoring practices are robust (e.g. reliable and accurate) and provide a sound picture for justification of future CO_2 reductions. This may include process optimisation or upgrades (to newer technologies). A gated investigation could be carried out including: 1) process investigations (identifying opportunities); 2) development and evaluation of those opportunities (with detailed economic analysis); and 3) justification for CCS retrofit. At any stage the investigations could be concluded. A variation of this could include expansion to new projects and processes not yet developed in New Zealand.
- **Development of National Approach to Assessing future CCS Applications** – as a follow-up to the stakeholder education process, a national framework could be developed to ensure all local authorities are familiar with CCS, its applications, the technologies involved, the existing experience in NZ (leveraging off the Oil and Gas industry) and the role of CCS in NZ emission reductions.

- **Environmental Planning** – The current information is lacking with respect to the environmental impacts of future CCS development and in particular the storage aspect. These are research areas which should be investigated more thoroughly to support mitigation of the EHS concerns associated with CCS. These include: contaminant mobilisation due to injection of CO_2 e.g. displacement of brine, acidification effects of high CO_2 partial pressures, and supercritical CO_2 mobilising organics; development of characterisation tools for baselining and monitoring CCS storage; and impacts of CO_2 injection on the microbial diversity of deep aquifers (this may enhance mineral carbonation and containment of stored CO_2).

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Attachment 1
Carbon Capture Technologies

1. CARBON CAPTURE TECHNOLOGIES

1.1 Introduction

The large CO_2 emission sources in New Zealand, summarized in Figure 1.1, provide a broad range of opportunities for CO_2 capture. This report reviews publicly available information on these sites and provides CO_2 capture technology options for reducing CO_2 emissions from these sites. For the sites where CO_2 capture is not applicable or practical, as in the case of aluminium reduction, other technology options to mitigate CO_2 emissions are discussed. The discussions provided herein are considered to be high level and are provided as background information to illustrate some of the impacts required with a CCS retrofit to an existing industry.

There are three primary technology groups considered for retrofit CO_2 capture of existing plants; post-combustion capture, pre-combustion capture and oxyfuel combustion. A fourth option would be to focus on process technologies that already have some CO_2 separation. The capture technologies applicable to a specific region are dependent on the CO_2 sources, processes present, and the timeframe for implementing CO_2 capture. Additional considerations include the location of storage sites and transportation options.

This remainder of this report is divided into two Parts. Part 1 focuses on the application of CO_2 capture technologies to the specific CO_2 emissions sources in New Zealand and highlights project impacts. Part 2 provides a detailed description of CO_2 capture technologies (post-combustion capture, pre-combustion capture and oxyfuel combustion) and the status of these technologies with regards to their maturity.

Figure 1-1 Summary of large CO_2 emitting facilities with breakdown of sources on site. Multiple values are shown to illustrate variation between data sources.

Site Name	Process	Breakdown of emission sources/process description	Fuel	CO_2 Emissions (kT/yr)
Power Generation				
Huntly	Power	4x250MW boiler/steam turbine	coal/gas	
		400MW NGCC	gas	
		48MW gas turbine	gas	
		Total		4,200[17]
Otahuhu	Power	Otahuhu A 4 simple cycle gas/diesel turbines used for peaking	gas/diesel	
		Otahuhu B NGCC 404 MW	gas	
		Total		1,000[17]
Stratford	Power	Taranaki NGCC 377MW	gas	
		GT peaker power 200 MW (Future)	gas	
		Total		1,000[17]
Industrial Sources				
RioTinto Alcan	Aluminium Smelter	Anode reaction		80% of total emissions
		Anode baking		
		Other combustion processes		
		Total		540[17]

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[17] B. Fiel et al, "New Zealand Carbon Storage Site Assessment: Phase 2," CO_2CRC Report Number RPT09-1579, December 2009.

Site Name	Process	Breakdown of emission sources/process description	Fuel	CO_2 Emissions (kT/yr)
Marsden Point	Refinery	Hydrogen production		200(?)
		Fuel combustion and flaring		910
		Total		910[17]
Golden Bay	Cement	Kiln emissions from limestone calcination		500+[17]
Holcim	Cement	Kiln emissions from limestone calcination		400[17]
GHB Glenbrook/ New Zealand Steel	Steel	Multi hearth furnace		
		Rotary kilns reduction of iron oxides to sponge iron with carbon from coal		
		KOBM Furnace, oxidation of remaining carbon and other impurities		
		Total		1,910[17]
Kapuni/Vector	Natural Gas Processing	Separation of CO_2 from recovered NG		750[17], 800[18]
Methanex Motunui	Methanol	Fuel combustion		1,223(WP Report 1)

PART 1: NEW ZEALAND CAPTURE

1.2 Application of CO_2 Capture to NZ Emissions Sources

No single CO_2 capture technology is applicable to all CO_2 emissions sources. The process that generates the CO_2 has a strong influence on the characteristics (CO_2 concentration, general gas composition, and pressure) of the stream from which the CO_2 must be separated and the requirements for obtaining the specifications for transporting and storing the CO_2. The following subsections address the suitable CO_2 capture technologies for the CO_2 emission related to power generation and other industries.

1.3 Power Generation

New Zealand's fossil fuel fired power generation fleet contains a mixture of coal/natural gas fired boilers, natural gas fired combined cycle units (NGCC), and natural gas fired/diesel simple cycle units. The simple cycle units are typically run for short durations with low annual capacity factors to meet peak demand. This type of unit is not typically considered for carbon capture due to the complexity of operating capture equipment under these conditions and the low annual CO_2 output. Therefore, the discussion regarding the CO_2 capture for power generation is limited to the existing coal/natural gas fired boilers and NGCC units.

1.3.1 Coal/NG Fired Boilers

For existing coal/natural gas fired boilers, the primary CO_2 capture technologies to consider for a retrofit application are:

- post-combustion capture (based on the CO_2 concentration, 12-14% CO_2); and
- oxyfuel combustion.

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[18] R. Funnell, "Overview of New Zealand's CO2 storage options," Proceedings of the International Carbon Capture and Storage Seminar, Monday, 27 April 2009, Wellington, New Zealand available at: http://www.crl.co.nz/publications/Corporate/CCSproceedings.pdf

The retrofit involves adding equipment for separating the CO_2 from the existing flue gas flow, drying the separated gas and compressing the CO_2 for transportation. The addition of the CO_2 capture and CO_2 compression adds to the cost of electricity through the additional equipment, potential reduction in steam cycle efficiency and additional plant auxiliary loads. The decrease in steam cycle efficiency and additional plant auxiliary load reduces the net plant efficiency increasing the amount of fuel required to produce a unit of electricity. Details of post-combustion and oxyfuel combustion technologies are provided in Sections 1.8 and 1.9. The following subsection includes a description of the potential changes to the existing generation facility required to implement these technologies.

Post-Combustion Capture for Existing Boilers

Chemical solvent based scrubbing technologies are considered state-of-the-art for retrofitting existing boilers with post-combustion CO_2 capture. While monoethanolamine (MEA) has been demonstrated commercially, several other potential solvents are being explored to reduce the energy requirements for solvent regeneration and capital costs through smaller equipment size. To implement post-combustion capture with existing boilers requires the following major equipment:

- CO_2 capture equipment (CO_2 absorber and solvent regenerator)
- Flue gas conditioning, including cooling and reduction of SO_2 levels
- CO_2 dehydration equipment
- CO_2 compression equipment
- Balance of plant equipment to provide utilities for the above processes, such as cooling and makeup water, electric power, etc.

In addition to the equipment additions, the facility configuration is typically changed to divert low pressure steam from the low pressure steam turbine to the solvent regeneration. This reduces the efficiency of the steam cycle and the amount of electricity generated. The net generation of the facility is reduced through the auxiliary loads related to:

- Circulation of the capture solvent
- Flue gas pressure boosting to compensate for pressure losses in CO_2 absorber
- Compression of the CO_2

Oxyfuel Combustion Capture for Existing Boilers

To implement oxyfuel combustion capture with existing boilers requires the following major equipment:

- Air separation unit
- Oxyfuel burners for boiler
- Gas recirculation ducting and fans
- SO_2 removal system for recirculated gas stream
- CO_2 purification system
- CO_2 pressurization
- Balance of plant equipment to provide utilities for the above processes, such as cooling and makeup water, electric power, etc

While the steam cycle efficiency is not reduced with oxyfuel combustion capture of CO_2, the net generation of the facility is reduced through the auxiliary loads related to:

- Air separation unit
- Purification and pressurization of the CO_2

1.3.2 NGCC

The three general approaches to capturing CO_2 generated from natural gas power generation applications are post-combustion, pre-combustion and oxycombustion.

In the case of pre-combustion capture, the natural gas fuel can be decarbonised via reforming process. The resulting synthesis gas (syngas) is further processed in a water-gas shift reactor to convert CO to CO_2 and increase H_2 concentration. Subsequently, CO_2 is removed from the shifted syngas stream to produce a hydrogen rich syngas. Firing hydrogen-rich syngas instead of natural gas would require potential significant modification to the combustion turbine.

Oxycombustion uses nearly pure oxygen instead of air for combustion of the fuel, resulting in a flue gas that is mainly water vapour and concentrated CO_2 (more than 60 percent by volume). The water vapour is then removed by cooling, condensation, and compression. In oxycombustion, flue gas is recycled back to the combustor to moderate the high flame temperature that results from combustion in pure oxygen. This process also requires the upstream separation of oxygen from air, with a purity of 95 to 99 percent in most cases. While several advanced concepts of natural gas and oxygen fired combined cycle are being developed, significant research and development is still required.[19] This technology remains unproven in NGCC applications and is only provided for reference.

In summary, while post-combustion, pre-combustion, and oxyfuel combustion technologies have been considered for CO_2 capture from NGCC units[20], post-combustion CO_2 capture is the most viable option for near term retrofits of existing units.

Implementing post-combustion capture with existing NGCC units requires the following major equipment:

- CO_2 capture equipment (CO_2 absorber and solvent regenerator)
- Flue gas cooling
- CO_2 dehydration equipment
- CO_2 compression equipment
- Balance of plant equipment to provide utilities for the above processes, such as cooling and makeup water, electric power, etc

In addition to the equipment, the facility configuration is typically changed to divert low pressure steam from the low pressure steam turbine to the solvent regeneration. This reduces the efficiency of the steam cycle and the amount of electricity generated. The net generation of the facility is reduced through the auxiliary loads related to:

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[19] "IPCC Special Report on Carbon Dioxide Capture and Storage, Intergovernmental Panel on Climate Change," p. 125-126, Cambridge University Press, New York, USA.

[20] H. M. Kvamsdal, O. Maurstad, K. Jordal, O. Bolland," Benchmarking of gas-turbine cycles with CO2 capture," 7th International Conference on Greenhouse Gas Control Technologies, Canada, 5-9 September 2004.

- Circulation of the capture solvent
- Flue gas pressure boosting to compensate for pressure losses in CO_2 absorber
- Compression of the CO_2

1.4 Industrial Sources

New Zealand industrial sites with major CO_2 emissions include natural gas processing, cement production, refinery operations, methanol production, iron/steel production, and primary aluminium production. The following subsections discuss the potential for CO_2 capture and options for CO_2 reduction in these industries.

1.4.1 Natural Gas Processing

The removal of CO_2 from natural gas extracted with a high concentration of CO_2 (similar to the Kapuni Gas Treatment plant) provides an ideal opportunity for carbon capture in that the CO_2 separation step is part of the existing industrial process. The CO_2 separated from natural gas has been used as a CO_2 source for EOR operations at the ExxonMobil Shute Creek[21] facility and to reduce CO_2 emissions at the Sleipner and Snøhvit sites in Norway. At these facilities, pre-combustion type CO_2 capture processes, such as MDEA[22], have been used for the separation of CO_2 from the natural gas stream.

The Kapuni natural gas processing involves the removal of CO_2 from the wellhead gas using a potassium carbonate reagent and is illustrated in Figure 1-1[23]. This process is commonly referred to as the Benfield process and has been applied extensively in industry for CO_2 separation.

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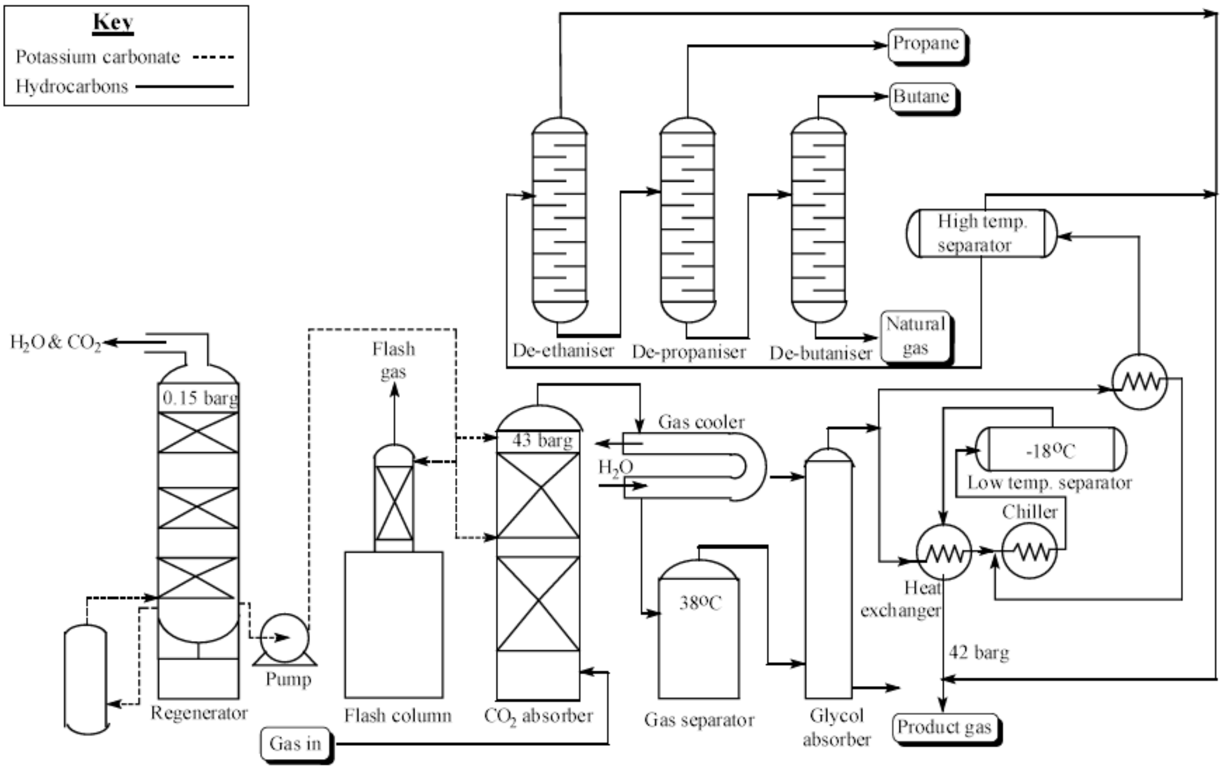
[21] Exxon Mobil – Shute Creek

[22] O. Kaarstad, "The Sleipner Project," IEA Asia Pacific Conference on Zero Emissions Technologies, Gold Coast, Queensland, Australia, February 18th, 2004.

[23] "The Processing of Natural Gas at Kapuni," Chemical Processes in New Zealand available on the New Zealand Institute of Chemistry Website at nzic.org.nz/ChemProcesses/energy/7C.pdf.

Figure 1-1 Block Flow Diagram for a Kapuni/Vector Natural Gas Processing Facility.[23]



This process reduces the CO_2 concentration in the gas from 42.6% to a level acceptable for sales. In the existing process, the CO_2 is dried[23] and a portion of the CO_2 can be used in industrial processes such as methanol production with the remainder vented to the atmosphere.[24] Based on the process description, some level of CO_2 compression equipment is available at the site. If full CO_2 capture was implemented in this type of process, the capacity and capabilities of the existing CO_2 drying and compression equipment would need to be reviewed to determine if the CO_2 specifications for transportation and storage can be met. A review may reveal that additional CO_2 drying and compression equipment is not required, hence the existing plant may support CCS without retrofit.

1.4.2 Cement Production

The CO_2 generated from the production of cement is a result of fuel combustion and decomposition of the limestone to CO_2 and CaO. There are two cement production facilities in New Zealand that emit CO_2 at rates potentially suitable for CO_2 capture – Golden Bay and Holcim.

The capture of this CO_2 from the exhaust of cement kilns is similar to that of coal fired boilers except for the greater CO_2 concentration (14 to 33 vol% dry) in the exhaust stream related to the calcination of limestone. Based on the cement production process, post-combustion and oxyfuel capture technologies have been determined to be most suitable of the mature technologies for CO_2 capture. Pre-combustion capture technologies which reduce the carbon content in the fuel in favour of H_2, are not considered practical due to the safety issues surrounding the use of H_2 as a fuel in the cement process. In addition to these

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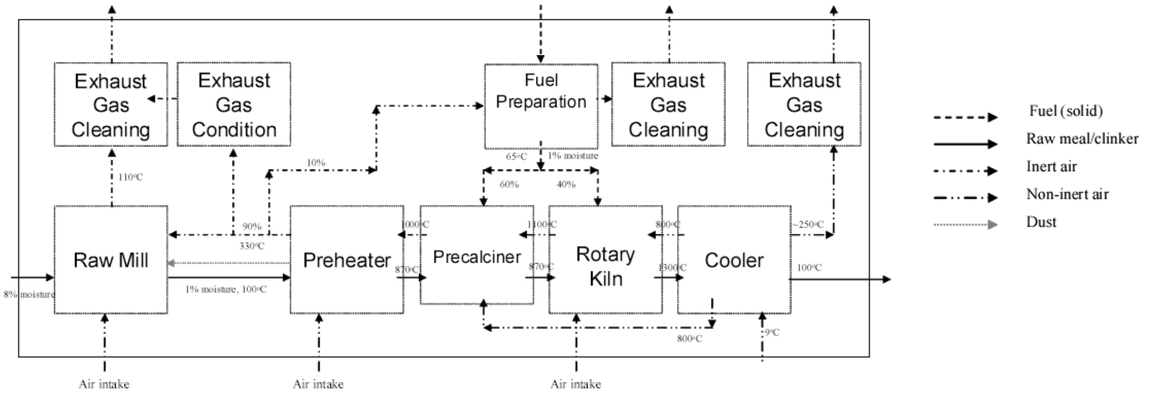
[24] B. Field et al, “New Zealand carbon dioxide storage site assessment: Phase 2”, CO2CRC Report Number RPT09-15879, (2009).

technologies, new technologies including the precalcination of limestone have been proposed[25]. Details regarding post-combustion and oxyfuel combustion processes are provided in Sections 3.7 and 3.8 while further details of applying CO_2 capture to cement production are discussed in the following.

Figure 1-2 provides a basic description of the cement making process. The heat for the process is derived from the combustion of fossil fuels, typically coal, with air. Heat recovery is incorporated in the process to improve efficiency and reduce fuel costs. Not included in the diagram are the cement milling, packing and loading processes.

Figure 1-2 Block Flow Diagram for a Typical Cement Plant without CO_2 Capture.[26]



Post-combustion CO_2 Capture in Cement Plants

As discussed above, the gas composition from the cement kiln is amiable to post-combustion CO_2 capture. A flow diagram illustrating the application of an MEA post-combustion capture system on the non-capture process is presented in Figure 1-3.

Considerations specific to implementing this capture technology to the cement industry include:

- ***SO_2 and NO_2 in the exhaust stream***. SO_2 and NO_2 present in the gas stream, from S in the fuel and feedstocks, can lead to degradation of the amines in the CO_2 capture unit to form heat stable salts. The addition of the wet flue gas desulphurisation (FGD) provides a method of reducing the SO_2 to the desired levels. Further, the wet FGD provides cooling of the gas stream from approximately 110°C to less than 50°C required by the absorption system.
- ***Particulate***. Particulate matter can reduce the efficiency of the amine scrubber system over time. Therefore the addition of an electrostatic precipitator (ESP) is required to achieve acceptable particulate levels.
- ***Steam for Capture Solvent Stripping***. Low pressure steam is required to remove the CO_2 from the capture solvent. Based on the current process and use of recovered heat for preheating, a boiler is required to generate the steam for solvent regeneration. This boiler can be incorporated in a combined heat and power process to also provide steam for power generation to be used on site.

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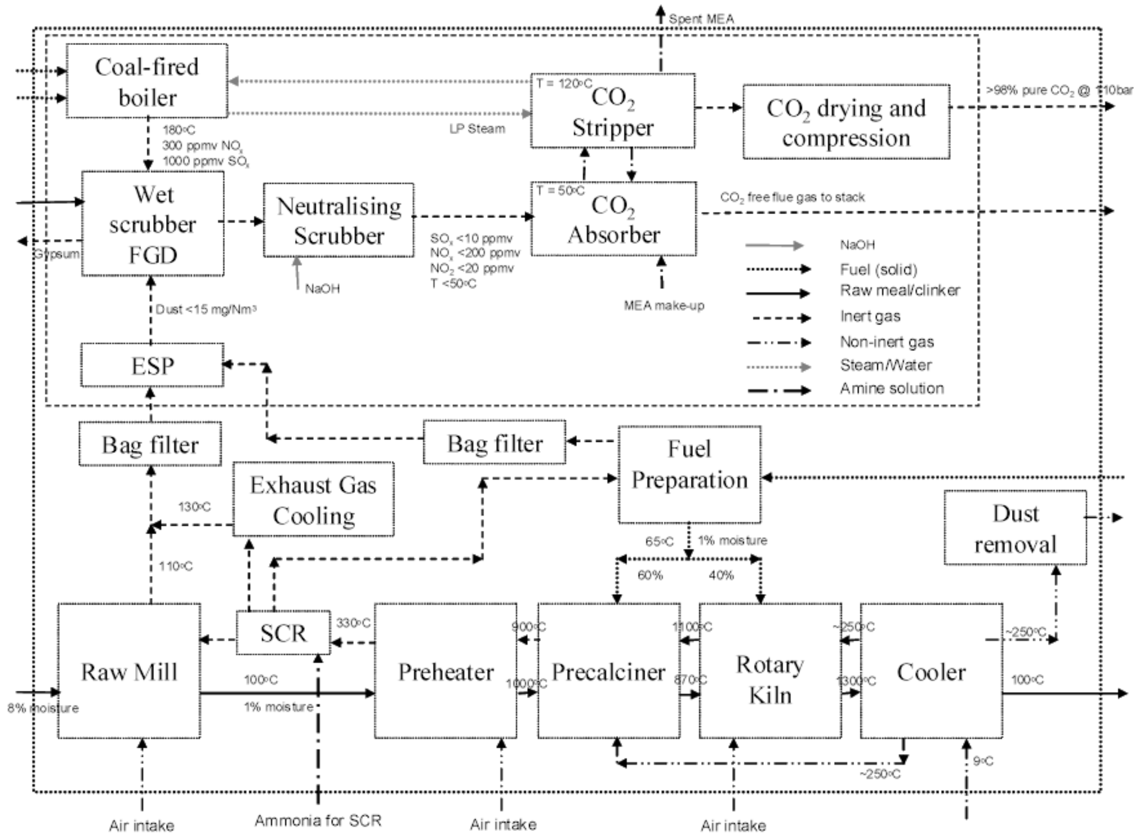
[25] N. Rodriguez, M. Alonso, J.C. Abanades, G. Grasa, R. Murillo, “Analysis of a process to capture the CO2 resulting from the pre-precalcination of the limestone feed to a cement plant,” Energy Procedia Volume 1, Issue 1, February 2009, Pages 141-148, Greenhouse Gas Control Technologies 9, Proceedings of the 9th International Conference on Greenhouse Gas Control Technologies (GHGT-9), 16–20 November 2008, Washington DC, USA.

[26] D.J. Barkera, S.A. Turner, P.A. Napier-Moore, M. Clark, J.E. Davisonc, "CO2 Capture in the Cement Industry," Energy Procedia Vol. 1, No. 1, 87-94, Greenhouse Gas Control Technologies 9, Proceedings of the 9th International Conference on Greenhouse Gas Control Technologies (GHGT-9), 16–20 November 2008, Washington DC, USA , (2009).

Figure 1-3 Block Flow Diagram for a Typical Cement Plant with Post-combustion CO_2 Capture.[26]

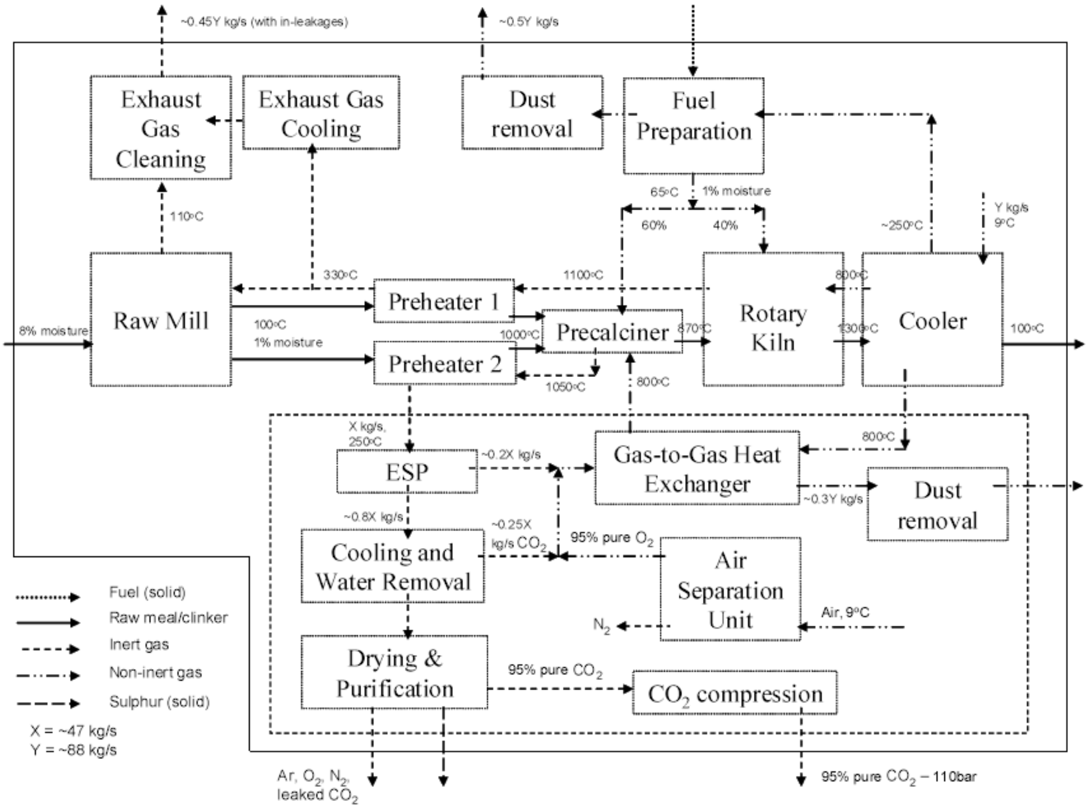


Oxyfuel Combustion CO_2 Capture in Cement Plants

Oxyfuel combustion has been considered as a potential method of reducing CO_2 emissions from cement plants. To date, this work has been limited to conceptual studies. Significant effort, including pilot scale and demonstration testing, is required before commercialisation.

Figure 1-4 provides a block flow diagram illustrating a cement plant with oxyfuel combustion CO_2 capture.

Figure 1-4 Block Flow Diagram for a Typical Cement Plant with Oxyfuel Combustion CO_2 Capture.[26]



Technical issues regarding the specific application of oxyfuel combustion to cement production include:

- ***Wear.*** Higher furnace temperatures combined with the nature of the cement process could potentially lead to higher wear rates of the kiln walls.
- ***Process Chemistry***. The impacts of the change in the kiln atmosphere on the properties of the final product have not been investigated.
- ***Air Dilution***. In existing cement kilns there is significant air in leakage which will dilute the CO_2 with N_2 and O_2. This contamination will lead to an increase need for purification of the CO_2 product.
- ***Energy Requirement of ASU.*** The auxiliary load related to the ASU is large and needs to be considered in the design. Where sufficient power from off-site generation is not available, power generation on site may need to be considered.

1.4.3 Refinery Operations Including H_2 Production

Refinery operations typically produce CO_2 emissions from the production of H_2 to be used in the refining process and process heating. In the production of H_2, the separation of CO_2 from the process gas stream is currently incorporated in the process using pre-combustion type capture technologies. To date, CO_2 is not commonly separated from the emissions related to process heating. For these emission sources, post combustion technologies are most suitable. The following subsections provide further details regarding CO_2 capture to refinery operations.

H_2 Production

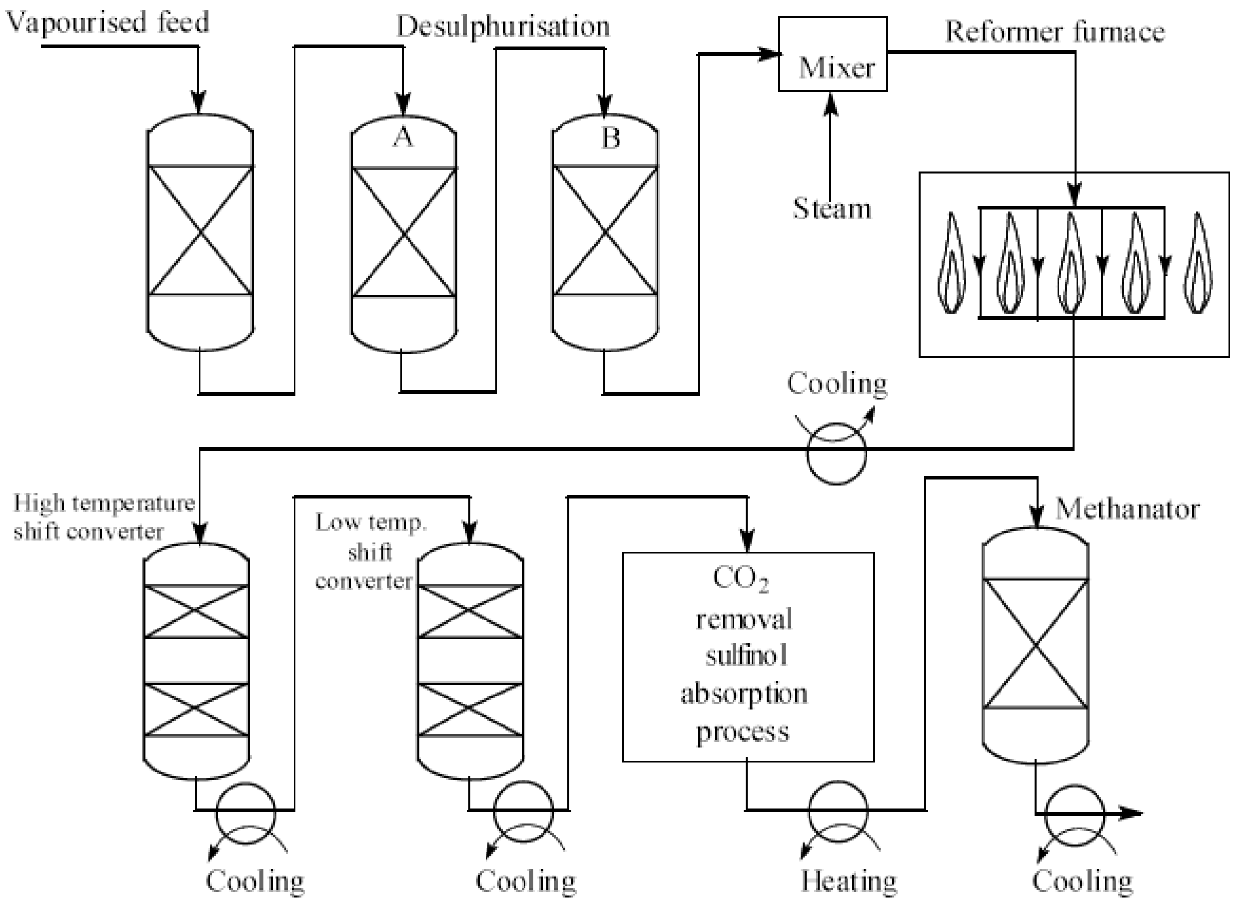
At the Marsden Point Refinery around 231 kT CO_2/yr are generated from the production of H_2. The "Refining Crude Oil" chapter of Chemical Processes in New Zealand provides a description of the H_2 manufacturing process at the Marsden Point Refinery.[27] In this process, hydrocarbons (C_nH_m) are reacted with water (as steam) in a steam reformer over a catalyst to produce an H_2 and CO_2 rich gas stream through the following reactions:

$$C_nH_m + n\,H_2O \rightarrow nCO + ((2n+m)/2)H_2$$

$$CO + H_2O \rightarrow CO_2 + H_2 \qquad \text{(water shift reaction)}$$

A block diagram of the equipment for this process is shown in Figure 1-5. At the Marsden Point refinery, the CO_2 is separated from the gas stream with a regenerable absorption process based on a Sulfinol solvent. The CO_2 captured and separated from the hydrogen manufacturing unit is purified to produce a food grade CO_2 product. In the case of where a portion of the CO_2 would be directed to sequestration, the existing equipment would need to be reviewed to ensure that sufficient compression and drying capacity exists to meet the pipeline specifications.

Figure 1-5 Flow Diagram for Hydrogen Manufacturing Unit at Marsden Point Refinery



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[27] "Refining Crude Oil," Chemical Processes in New Zealand available on the New Zealand Institute of Chemistry Website at http://nzic.org.nz/ChemProcesses/energy/7A.pdf

General Refinery Operations

At refinery sites, there are several smaller CO_2 emission sources related to process heating. While the individual emission sources would be considered small, the total CO_2 emissions from these sources are significant. The compositions of these gas streams are assumed to be typical of hydrocarbon fuel combustion with CO_2 content of 10-14% and at atmospheric pressure. Based on the gas composition, post-combustion capture technologies would be most suitable with near term implementation using an MEA solvent. Challenges to implementing CO_2 capture on this site include the potential of high sulphur content in the flue gas streams related to the fuel and the multiple emission sources and space availability.

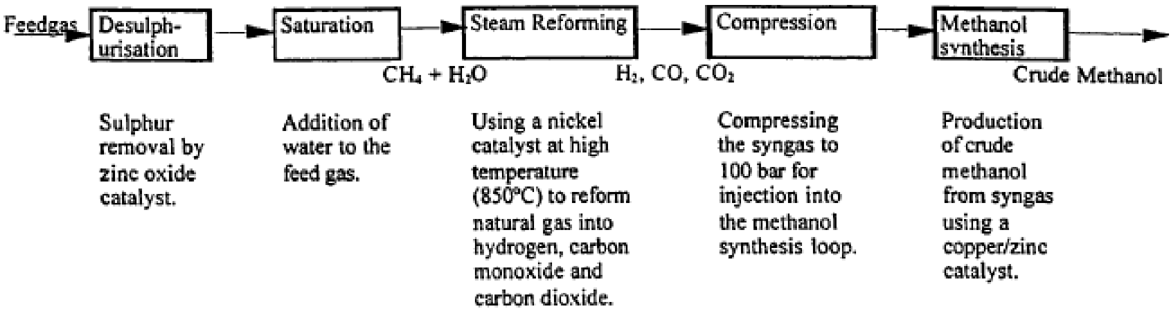
The high sulphur in the flue gas streams can lead to a degradation of the capture solvent leading to a large makeup stream and cost to the project. Therefore, prior to the CO_2 capture, a sulphur removal system is required, typically a caustic scrubbing system which reduces the sulphur content to a few parts per million.

For the distributed emission points on a refinery site, the use of a single CO_2 removal system should be investigated to take advantage of economies of scale and limit the need for multiple processes at the individual emission points. In the case of a single capture unit, the gas streams are ducted from the individual processes to the centralised CO_2 capture unit. After the CO_2 capture using post-combustion technologies, as with other post-combustion processes, the CO_2 is dried and compressed. Similar to the other post-combustion applications discussed, for near term deployment amine based solvent technologies are most likely to be used.

1.4.4 Methanol Production

Methanol production at the Methanex Motunui plant also produces significant CO_2. A flow diagram of the process is provided in 1-6 shows methane and water (as steam) are reacted in a steam reformer to produce a syngas which is compressed and reacted over a catalyst to produce a crude methanol, a combination methanol and water. This crude methanol is then distilled to produce methanol for sales. The methanol production reaction over the catalyst is incomplete leading to H_2 and CO leaving the reactor. After separating the methanol from these gases, a portion of this gas stream is recycled into the reactor for methanol production and the remainder, a purge, is burned in the reformer as fuel.

Figure 1-6 Flow Diagram for Methanol Production at Motunui Facility[28]



The CO_2 emissions from the process are from the heating in the gas reformer and the distillation of the crude methanol. The fuel for these processes is a combination of natural gas and the purge stream from the process containing H_2. For the selection of a capture technology, the gas emitted from the heating

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[28] "The Production of Methanol and Gasoline," Chemical Processes in New Zealand available on the New Zealand Institute of Chemistry Website at http://nzic.org.nz/ChemProcesses/energy/7D.pdf

processes is assumed to have a similar composition to that of a natural gas fired boiler with CO_2 content in the order of 10%. Based on this gas composition, post-combustion capture is suitable for the capture of CO_2 from this gas stream.

Sulphur is a concern to the post-combustion capture options. Based on the diagram above, sulphur removal is currently performed on the fuel entering the system to protect the catalysts used in the chemical process. Therefore, the purge gas stream should have an acceptably low sulphur content for the post-combustion process.

1.4.5 Iron Steel Production

The two major iron and steel processing facilities in New Zealand are the New Zealand Steel Ltd. (BHP) and Pacific Steel Ld. facilities. The Pacific Steel facility uses an electric arc furnace technology to process scrap steel. This process does not have significant CO_2 emissions and therefore is not typically considered an opportunity for CO_2 capture.

The New Zealand Steel Ltd. facility produces steel through the reduction of titanomagnetite sand by using a combination of rotary reduction kilns and a Kockner Oxygen Blown Machutte oxygen steel-making furnace as illustrated in Figure 1-7.[29] This arrangement is different than the more common blast furnace used for the reduction of iron ores in that the iron reduction occurs in rotary kilns by a directly reduced iron (DRI) process to produce iron sponge.

The red arrows in Figure 1-7 indicate emissions from the processes. The exhaust stream from the Multi-hearth furnace contains the coal volatiles from the heating of the coal and is currently fired in the boiler to raise steam for power generation. The exhaust stream from the rotary kiln is generated from the carbon in the coal reacting with the oxygen in the iron ore and air introduced into the kiln. Based on the operating temperatures of this furnace, the gas stream is assumed to be primarily CO and CO_2 with some N_2. Currently, this stream is burned to convert the CO to CO_2 prior to discharge into the atmosphere. The emissions from the remaining units are generated from the reaction of primarily C and S remaining in the slag with O_2 introduced to the melter. Based on a general description of the rotary kiln process[30], the gas compositions primarily contain N_2, CO and CO_2 with using air as the oxidizer. Approximately 75% of the carbon in this stream is as CO_2 and the remainder is CO.

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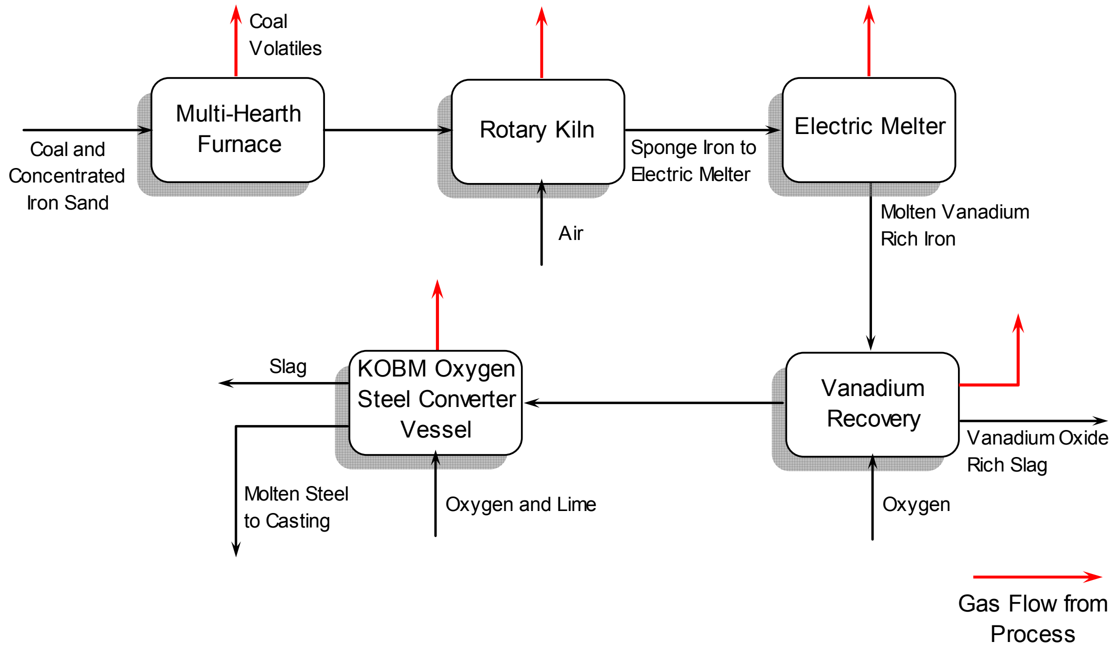
[29] "The Manufacture of Steel," Chemical Processes in New Zealand available on the New Zealand Institute of Chemistry Website at: http://nzic.org.nz/ChemProcesses/metals/8A.pdf

[30] A.E. Morris, A. Deneys, R. Jones, J. Bartlett, W. Smith, S. Howard, "Computer Modeling and Analysis of Processes for the Production and Use of DRI," in Direct Reduced Iron, Technology and Economics of Production and Use, edited by J. Feinman, pp. 173-189 (1999).

Figure 1-7 Block Diagram of Steel Production Process at the BHP NZ Glenbrook Facility.

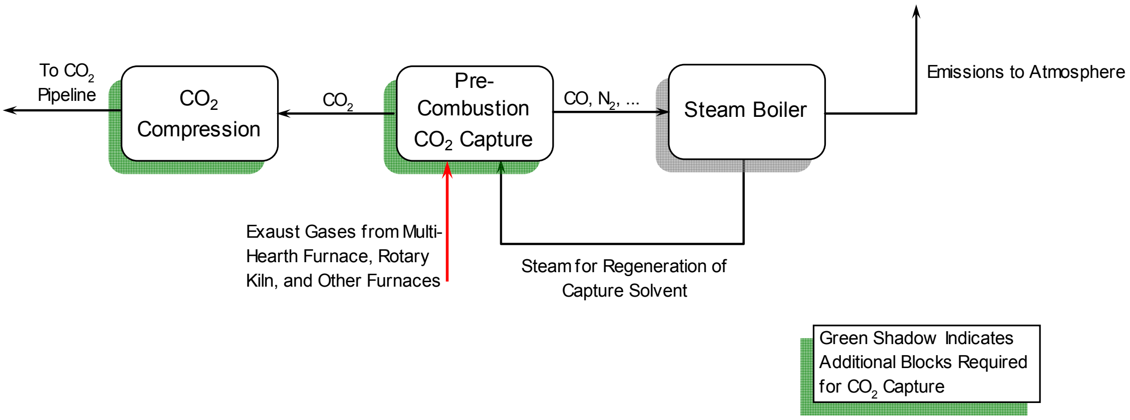


Based on the similarity of gas compositions of these streams to syngas, moderate CO_2 concentrations and low O_2 concentrations, pre-combustion technologies are suitable for a potential carbon capture at this facility. A detailed discussion of pre-combustion capture technologies is provided in Section 1.8. Two options are considered, a moderated CO_2 capture and a high carbon capture option.

Moderate CO_2 Capture Option

In the moderate carbon capture option, the gases are collected and then passed through the CO_2 capture process and then the remaining gas combusted in the existing boiler to raise steam for power generation and regenerating the capture solvent. Assuming 75% of the carbon is CO_2, and a 90% CO_2 capture efficiency, then a 67% reduction in the CO_2 emissions from the facility would be expected.

Figure 1-8 Block Diagram for Moderate CO_2 Capture Option for BHP Glenbrook Steel Process



As illustrated in Figure 1-8, the addition of the capture system would require the addition of CO_2 capture and CO_2 compression equipment. The existing steam boiler could potentially provide steam for the solvent regeneration. The final configuration of this option would require a more detailed assessment of the process existing at the site including:

- Evaluation of the gas composition from the different processes
- Potential of existing boiler to provide sufficient steam to the capture system
- Impact of redirect steam from power generation to solvent regeneration and the availability of replacement power

High CO_2 Capture Case

The high capture case is a modification of DRI processes similar to the moderate capture case, but instead of combusting the CO and H_2 in the boiler, these gases are reintroduced into the rotary kiln where they can react with the iron oxides to form H_2 and CO_2. One of the primary disadvantages of this arrangement is the loss of steam and electric power production. Further assessment of this option should include determining the availability of the electricity from offsite and the amount of CO_2 that is emitted in its generation.

1.4.6 Primary Aluminium Reduction

Aluminium metal is produced through the reduction alumina dissolved in a cryolite bath by electrolysis. The major CO_2 emission sources in this process are:

- Generation of electricity for the electrolysis process
- Oxidation of the carbon electrodes
- Baking of the carbon anodes

At the RioTinto Alcan aluminium reduction facility, the electricity for electrolysis is produced through hydroelectric generation and therefore does not represent an opportunity for CO_2 capture. At the site, the major emission source, representing around 80% of the total CO_2, is the oxidation of the carbon electrodes. Based on the current configuration of collecting the gases above the pots via hoods, the concentration of CO_2 in the duct gas is very low and is not considered or discussed in the literature as a potential stream for CO_2 capture. An option currently being considered for eliminating this CO_2 emission source is referred to as an inert anode technology.[31] In this case, the carbon anode is replaced with an oxygen ion membrane that allow for the oxidation of the O^{2-} ions in the cryolite bath to generate O_2 gas.

1.5 Discussion of CO_2 Capture Options

The selection of sites to pursue CO_2 is strongly based on the capture technologies available to the site, transportation distances, CO_2 volume, and availability of a suitable storage site. This following discussion is limited to the capture options without consideration of transportation and storage. With respect to capture options, aside from capture volume which was taken into account in the selection of potential facilities, the criteria of capture implementation ease and technology maturity were considered.

Industrial processes such as natural gas processing and the hydrogen production currently have CO_2 separation steps included as a requirement of the process. These processes are considered to be "low hanging fruit" in that a significant portion of the equipment is currently in place for CCS and the energy penalties associated with the capture process are accepted by the industry. To produce a CO_2 flow that is suitable for CCS, drying and compression of the CO_2 is required. This equipment exists at the Kapuni gas

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[31] " Inert Anode Roadmap," prepared by the US DOE Energy Efficiency and Renewable Energy, 1998, available at the http://www1.eere.energy.gov/industry/aluminum/pdfs/inertroad.pdf

processing facility and hydrogen production facility at the Marsden Point refinery. To assess the requirements for future CO_2 capture for storage at these sites, an engineering review is required to determine the adequacy of the existing equipment to achieve the pipeline specification (pressure and water content of the CO_2). CO_2 drying and compression to meet pipeline specifications have been previously implemented on an industrial scale and similar applications.

The remaining potential New Zealand capture sites require more extensive equipment additions, primarily a CO_2 separation step, to the existing processes to capture CO_2. Further, the auxiliaries to support the capture process can have a significant cost on the overall process through reducing the overall process efficiency. Therefore, the changes required to implement capture are significant. Implementation of post-combustion CO_2 capture at the NGC power station would be the most beneficial based on the potential volume of CO_2 to capture and the maturity of post-combustion CO_2 capture technologies as applied to power generation.

For the remaining NZ processes, capture technologies have been developed, but the engineering solutions to address the barriers specific to the applications have not been demonstrated or tested on a commercial scale.

PART 2: CAPTURE & COMPRESSION TECHNOLOGIES

1.6 Capture & Compression Technologies

The capture of CO_2 involves the separation of CO_2 and its compression to pressures suitable for transportation in a pipeline to a storage site. Currently there are three primary technology groups consider for the separation of CO_2 from gas streams for CO_2 capture;

- Pre-combustion
- Post-combustion
- Oxyfuel combustion.

The following subsections provide a general background of these technologies along with their applicability. Additionally, a subsection on the compression of CO_2 is included.

1.7 Pre-Combustion Capture

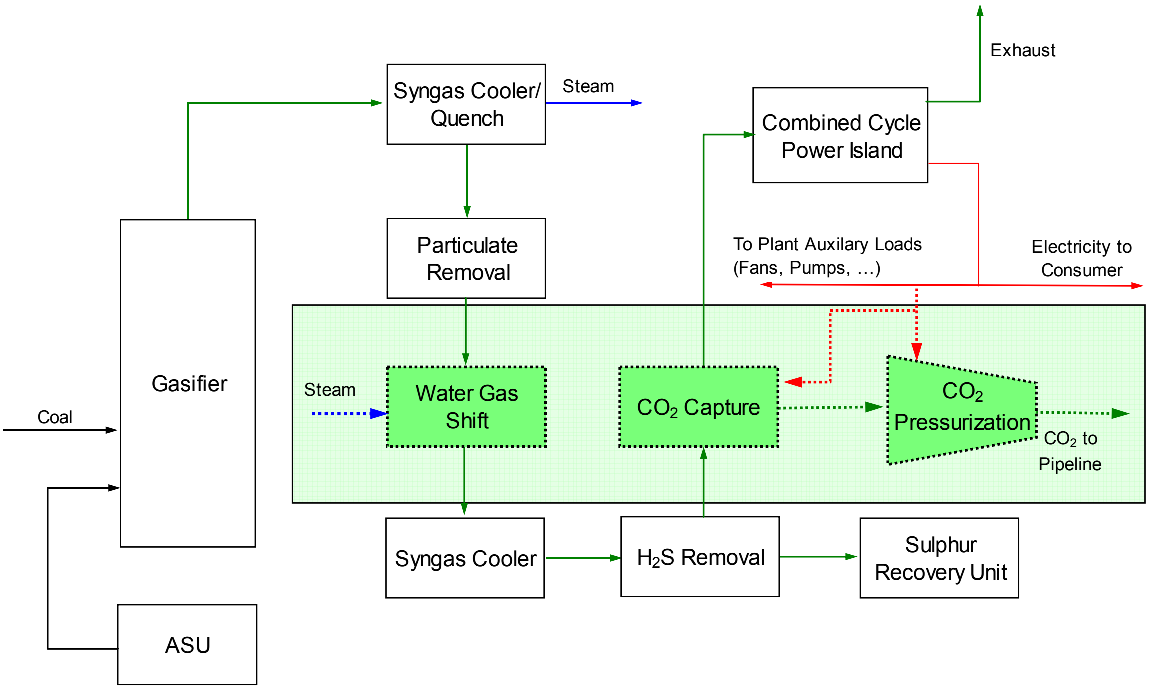
Pre-combustion CO_2 capture relates to gasification plants and NGCC with a H_2 rich syngas fired gas turbine, where solid, liquid or gas carbon containing feedstock is converted into gaseous components by applying heat under pressure and, in some systems, in the presence of steam. In a gasification and reformer reactors, the amount of oxygen available inside the gasifier is controlled so that only a portion of the fuel reacts completely to the products of combustion, namely, water and CO_2. This “partial oxidation” process provides the heat necessary to chemically decompose the fuel and produce syngas, which is composed of hydrogen, carbon monoxide, water vapour, carbon dioxide and minor amounts of other gaseous constituents, such as methane.

For solid and liquid fuels, a gasifier is used to convert the fuel to syngas as illustrated in Figure 1-9.

In the process, oxygen for gasification is generated in the ASU and combined with the solid fuel and water in the gasifier to produce the syngas. Raw syngas exiting the gasifier is cooled and cleaned of particulate before being routed to a series of water-gas shift reactors and raw gas coolers. These components convert carbon monoxide and steam present in the raw gas to CO_2 and hydrogen, thereby segregating the carbon as CO_2 in the high-pressure raw syngas stream, which improves the driving force for various types of separation and capture technologies termed as acid gas removal (AGR) systems. Once concentrated, CO_2 can be removed during the desulphurisation process through use of a double-staged AGR unit. Near-term applications of CO_2 capture from pre-combustion streams will likely involve physical or chemical absorption processes, with the current state-of-the-art being a physical glycol-based solvent called Selexol. Regeneration gas from the AGR plant is fed to a sulphur recovery unit to produce elemental sulphur or other sulphur compounds. Captured CO_2 is dehumidified and compressed to supercritical conditions for pipeline transport.

The hydrogen rich sweet syngas exiting the AGR system is conveyed to a combustion turbine where it serves as fuel for the combustion turbine/HRSG/steam turbine power conversion system. The hot combustion gases are conveyed to the inlet of the turbine section, where they expand through the turbine to produce power to drive the turbine air compressor and electric generator. The turbine exhaust gases are conveyed through a HRSG. Waste heat is recovered from this process and used to raise steam to feed to a steam turbine. The exhaust gas from the combustion turbine and HRSG is released to the atmosphere via a conventional stack.

Figure 1-9 Simplified Block Flow Diagram for Power Generation with Pre-combustion Capture



Source: WorleyParsons

When applied to gaseous feedstock, syngas can be produced by heating a mixture of steam and natural gas to 800-900°C in presence of a catalyst (steam reforming). Another route is to partially oxidise (POX) gaseous fuel. The resulting syngas is further processed in a water-gas shift (WGS) reaction to convert CO to CO_2 and increase the hydrogen concentration. Subsequently, CO_2 is removed from the shifted syngas stream to produce a hydrogen rich fuel. The technologies most relevant for reforming natural gas include fired tubular reforming (FTR), also known as steam-methane reforming (SMR) and auto-thermal reforming (ATR). Processes that are commonly used to capture CO_2 from shifted syngas stream include: acid gas removal systems (AGR), such as chemical absorption, physical absorption, or hybrid chemical/physical absorption processes, and pressure/vacuum swing adsorption systems (PSA or VSA). The latter process is utilised to produce high purity hydrogen (>99.9 vol.%).

Gasification plants used for power generation and equipped with pre-combustion CO_2 capture suffer net efficiency decreases of approximately 6 to 9 percent, depending upon gasification technology utilised as compared to non-capture plants.[32] About 40 to 60 percent of this loss is a result of decrease in power generation by a steam turbine as large amounts of steam are utilised in the water-gas shift reaction instead of generating power. Electric power demand by the CO_2 capture system and compressors accounts for approximately 30 to 40 percent of energy loss.

In general, pre-combustion CO_2 capture technologies are favouring high pressure and low temperature, and are not suitable for working in oxidising atmospheres. Hence, pre-combustion CO_2 capture technologies are not suitable for a retrofit application of a pulverised coal-fired unit. This is further explained in the following subsections.

The separation of the CO_2 from the syngas can be accomplished using the following technologies:

- Chemical Solvent Absorption
- Physical Solvent Absorption
- Hybrid Physical/Chemical Solvent Absorption
- Pressure/Temperature/Electric/Vacuum Swing Adsorption
- Other Processes

Details regarding these technologies are provided in the following subsection.

1.7.1 Chemical Solvent Absorption

In a chemical absorption process the acid gases react to an intermediate liquid solvent species and are removed from the bottom of the absorber column with the rich solvent.

Diethanolamine (DEA) is a secondary amine. Like MEA, it can absorb CO_2. However, it is less reactive than MEA and is highly susceptible to oxygen degradation[33] that precludes DEA utilisation for post-combustion CO_2 capture application.

Methyldiethanolamine (MDEA) is a tertiary amine. In recent years, MDEA has acquired a much larger share of the gas-treating market. Compared with primary and secondary amines, MDEA has superior capabilities for selectively removing H_2S in the presence of CO_2. MDEA is resistant to degradation by organic sulphur compounds and has a low tendency for corrosion. Compared to MEA, it requires a relatively low circulation rate and consumes less energy. Commercially available are several MDEA-based solvents that are formulated for high H_2S selectivity. However, MDEA is not suitable for post combustion applications due to its oxygen-caused degradation[34]. MDEA has been used for H_2S removal in chemical

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[32] Cost and Performance Baseline for Fossil Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity, Final report, DOE/NETL 2007/1281, Revision 1, August 2007

[33] Dupart, M.S., Bacon, T.R. and Edwards, D.J. (all Gas/SPEC Technology Group), "Understanding Corrosion in Alkanolamine Gas Treating Plants", Hydrocarbon Processing, April and May 1993.

[34] "Process Screening Analysis of Alternative Gas Treating and Sulfur Removal for Gasification", prepared by SFA Pacific, Inc. for the US DOE National Energy Technology Laboratory, Revised Final Report, December 2002.

plants and IGCCs. The majority of chemical solvents are organics amine based. However, there are some alternative inorganic solvent systems such as Na/K carbonates.

Benfield Process. The Benfield process [35], also known as the hot carbonate process, uses an inorganic chemical solvent potassium carbonate (K_2CO_3) and catalysts. The process typically works at 70-120°C and 2.2-6.9 MPa. The Benfield process is widely used for purification of H_2 streams, and is not considered a good option for post-combustion CO_2 capture due to low pressure of the flue gas. This process is commercially available. Hot carbonates are well suited for CO_2 removal at moderate to high partial pressures in the feed. While hot carbonate plants have been used for bulk CO_2 removal, their relatively high solvent circulation and heat requirements make them more expensive than other processes.

1.7.2 Physical Solvent Absorption

Physical solvent scrubbing of CO_2 is a well established technology, which is widely utilised to treat both natural and synthesis gas streams. In a physical absorption process the acid gases are physically absorbed into the liquid solvent and are removed from the bottom of the absorber column with the rich solvent. The solubility of individual gas compounds in a physical solvent follows Henry's Law, and favours high pressure and low temperature operation. Physical solvents combine less strongly with CO_2 than chemical solvents. The advantage of such solvents is that CO_2 can be separated from them in the stripper mainly by reducing the pressure, resulting in much lower energy consumption. These solvents are better suited for applications at a higher pressure such as syngas streams in the coal-based IGCC process (typically 2.0 MPa or higher) and the concentrations of CO_2 are about 35 to 40 percent. Hence, the CO_2 partial pressure is much higher than in that in combustion flue gas.

The physical solvents are regenerated by multistage flashing to low pressures. Because the solubility of acid gases increases as the temperature decreases, absorption is generally carried out at lower temperatures, and refrigeration is often required.

Several physical solvents that use anhydrous organic solvents have been commercialised. The following are some commercially available physical solvents that could be used for CO_2 capture in applications, such as IGCC.

- **Rectisol.** The Rectisol process uses chilled methanol as a scrubbing solvent. Typically, the process works at temperatures -10 to -70 ºC and higher than 2.0 MPa. The process is licensed by Linde AG and Lurgi AG.
- **Selexol.** The Selexol process uses dimethylether of polyethylene glycol as the solvent. Typical working conditions are -20 to 40 ºC and 2.06-13.80 MPa.
- **Fluor Process.** The Fluor process uses propylene carbonate as the solvent. The solvent generally works below ambient temperature and at high pressure (3.1-6.9 MPa).
- **Purisol.** The Purisol process uses n-methyl-2-pyrolidone as the solvent. The process condition generally works at temperature of -20 to 40 °C and at high pressure (≥2.0 MPa).

Commercially available physical solvent scrubbing technologies generally require high pressure and low temperature, and hence are considered not preferable options for post-combustion CO_2 capture processes. However, some efforts are being made to develop new solvents that are expected to be suitable for post-combustion CO_2 capture such as ionic liquids.

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[35] http://www.uop.com/objects/99%20Benfield.pdf

1.7.3 Hybrid Physical/Chemical Solvent Absorption

Hybrid solvents combine the high treated gas purity offered by chemical solvents with the flash regeneration and lower energy requirements of physical solvents. Some commercially available scrubbing technologies that use a mixture of physical and chemical solvents are as follows.

- **Sulfinol.** The Sulfinol process is developed by Shell. The solvent is a mixture of diisopropanolamine (DIPA) and Sulfolane (tetrahydrothiophene dioxide). The former provides a chemical solvent and the latter a physical solvent. Meanwhile a modified solvent, known as Sulfinol-M, has been developed that uses MDEA as the chemical solvent. Sulfinol process typically works at a pressure higher than 0.5 MPa and can be used for applications such as IGCC.
- **Flexsorb™ PS.** The Flexsorb PS process is a mixed hindered amine/physical organic solvent version of the Flexsorb process developed by ExxonMobil. It is very stable and resistant to chemical degradation. It was developed to compete with the Sulfinol process. In one Canadian natural gas plant, Sulfinol-D was replaced with Flexsorb PS solvent to reduce the solvent circulation rate and reboiler duty.[36]
- **Ucarsol™ LE.** Ucarsol LE solvents offered by the Dow Chemical Company are used for high-efficiency acid gas removal. Ucarsol LE-701 is for selective H_2S and controlled CO_2 removal, while Ucarsol LE-702 is for complete acid gas removal, meeting low H_2S and CO_2 specifications. These are MDEA-based, physical/chemical hybrid solvents, which offer lower regeneration energy demand, lower hydrocarbon solubility and less degradation than other commonly used hybrid solvents, resulting in the potential for significant operating cost savings. [37]
- **Amisol.** The Amisol process was developed by Lurgi Germany. The process uses a mixture of MEA or DEA with methanol. The process works at ambient temperature and a pressure higher than 1 MPa (145 psia). The process has been applied down stream of a number of oil gasification units, but has not established a wide market.

1.7.4 Pressure/Temperature/Electric/Vacuum Swing Adsorption

Some solid materials with high surface areas, such as zeolites and activated carbon, can adsorb CO_2 and be used to separate CO_2 from gas mixtures by adsorption. The process operates on a repeated cycle with the basic steps being adsorption and regeneration. In the adsorption step, gas is fed to a bed of solids that adsorbs CO_2 and allows the other gases to pass through. When a bed becomes fully loaded with CO_2, the feed gas is switched to another clean adsorption bed and the fully loaded bed is regenerated to remove the CO_2. In pressure swing adsorption (PSA), the adsorbent is regenerated by reducing pressure. In temperature swing adsorption (TSA), the adsorbent is regenerated by raising its temperature, and in electric swing adsorption (ESA) regeneration takes place by passing a low-voltage electric current through the adsorbent.

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[36] Korens, N., Simbeck, D.R. and Wilhelm, D.J., “Process Screening Analysis of Alternative Gas Treating and Sulfur Removal for Gasification”, SFA Pacific, Inc., Dec. 2002.

[37] Dow Product Brochure: UCARSOL LE 701, 702, and 703 Solvents For High Efficiency CO2, H2S, and Mercaptan Removal, The Dow Chemical Company, July 2004.

Recent investigations into adsorption technology have shown that CO_2 recovery is also feasible under vacuum conditions (vacuum swing adsorption, VSA). Though VSA has not yet been commercially tested for CO_2 recovery, it is a promising emerging technology with application in CO_2 separation from blast furnace top gases, while the residual gases are recycled back to the furnace. This concept was recently tested with promising results at Metallurgical Research Institute (MEFOS) experimental facility in Luleå, Sweden within a framework of Ultra Low CO_2 Steel Making (ULCOS) project. [[38]], [[39]]

PSA and TSA have been employed commercially for CO_2 removal from synthesis gas for hydrogen production. ESA is not yet commercially available, but it is said to offer the prospect of lower energy consumption than the other processes. Adsorption is not yet considered attractive for large scale CO_2 removal from combustion flue gas because the capacity and CO_2 selectivity of available adsorbents is low. However, it may be successful in combination with another capture technology. Some development efforts for new sorbents are being taken to develop adsorbents that can operate at higher temperatures in the presence of steam with increased capacity and improved selectivity eg, dry regenerable carbonate sorbent.

1.7.5 Other Technologies

Some other technologies are being developed, which do not fit in the categories mentioned above. Enzymatic CO_2 capture process, developed by Carbonzyme Inc., uses an enzyme catalysed carbonic anhydrase-based liquid membrane biomimetic reactor. It is claimed that the technology is applicable to treating a large number of different flue gas streams eg, flue gases generated by combusting fuels such as natural gas, oil or various ranks of coal. The process operates at moderate temperature and pressure. It has the ability to separate CO_2 from other gases while using modest energy and employing no hazardous chemicals. However, the technology is still at early development stage.

1.8 Post-Combustion Capture

Post-combustion (PCC) capture technologies separate CO_2 from combustion (fully oxidised) flue gases. PCC is primarily applicable to conventional coal-fired power generation including PC (subcritical and supercritical) and fluidised-bed combustors, but may also be applied to gas-fired generation using combustion turbines. The combustion flue gases are low pressure streams (the ambient atmospheric pressure) with CO_2 concentrations typically ranging from about 4 percent by volume for NGCC plants up to about 14 percent by volume for coal fired boilers. For cement kiln applications, the CO_2 concentration can be as high as 30%. CO_2 capture from such flue gases presents design challenges, often requiring flue gas pre-conditioning to reduce its temperature and remove contaminants such as particulates, nitrogen oxides and sulfur oxides. Post combustion streams typically contain 3 to 6 percent by volume of oxygen. Most of the PCC technologies are suitable for a retrofit application to a coal fired power unit.

Based on the method of CO_2 removal, the following technologies can potentially be used for the PCC application:

- Absorption by regenerable solvent
- Adsorption on a solid bed
- Cryogenic separation

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[38] Air Liquide Press Release, "A world first in steel production to preserve the environment", April 8, 2008.

[39] G. Danloy et. al., "ULCOS - Pilot testing of the Low-CO2 Blast Furnace process at the experimental BF in Luleå", La Revue de Métallurgie Paris, N°1 (January 2009), pp. 1-8.

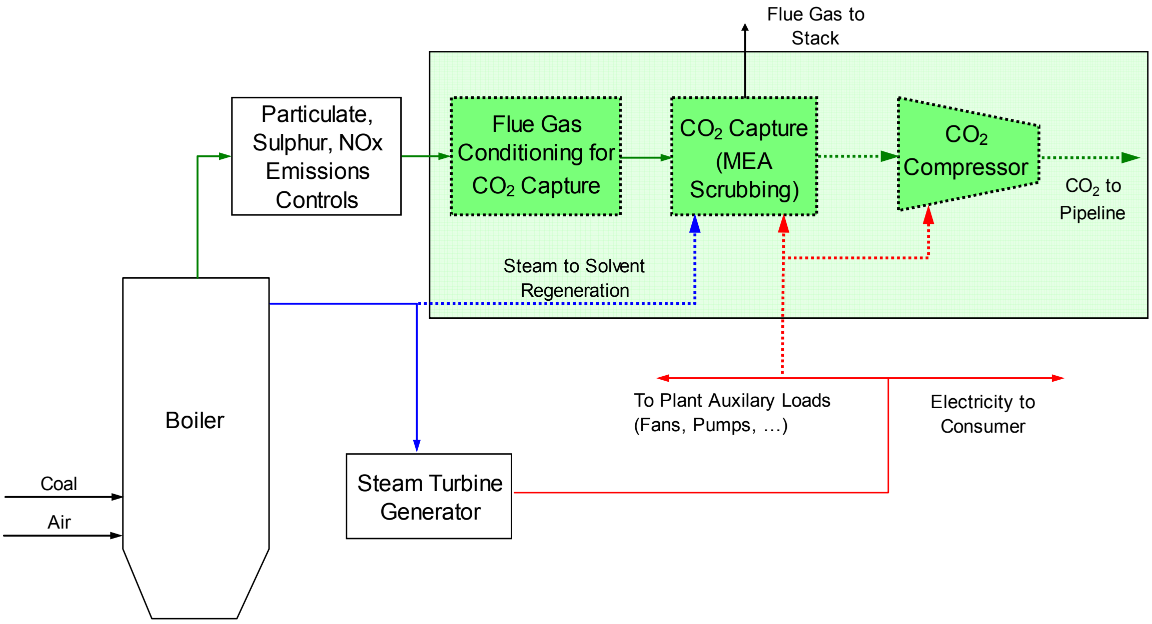
- Membrane separation

However, near-term applications of CO_2 capture from post-combustion streams will likely involve chemical absorption processes, with the current state-of-the-art being MEA based solvents. MEA scrubbing is currently the only commercially available technology that has been demonstrated for CO_2 capture from coal-fired boilers flue gas.

In a typical coal-fired power generation system, as illustrated in Figure 1-10, fuel is burned with air in a boiler to produce steam, and the steam drives a turbine to generate electricity. The boiler exhaust, or flue gas, consists mostly of nitrogen, water vapour, CO_2 and oxygen. The flue gas downstream of particulate removal and flue gas desulphurisation systems is quenched and polished to reduce concentration of impurities to levels suitable for CO_2 scrubbing in MEA system. Typically, scrubbers with dilute caustic solution are specified for this application. In the scrubber, the nitrogen oxides and sulphur dioxide in the flue gas react with the caustic solution to form soluble salts. These salts are removed by taking a purge stream from the caustic recirculation loop.

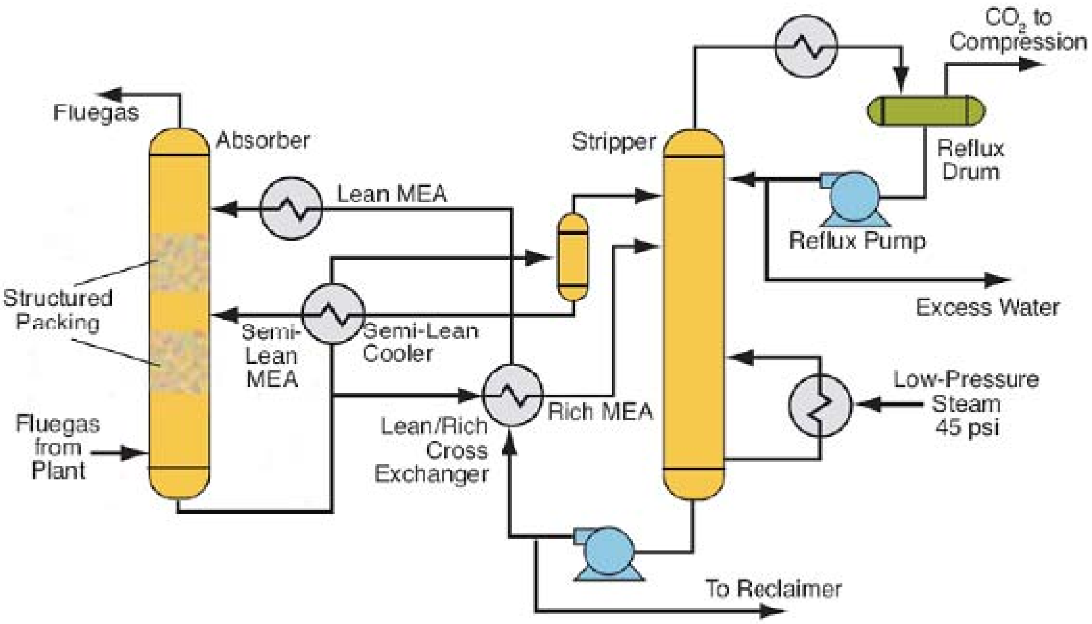
The flue gas from the caustic scrubber is further cooled in the flue gas cooler to remove additional water and scrubbed in the MEA absorber. The solvent MEA, a primary amine, reacts with CO_2 at around 40°C and ambient to intermediate pressure, which is suitable for post-combustion flue gas. The process consists of an absorber and regenerator, as shown in Figure 1-11, which are connected by a circulation of the MEA solution. In the absorber the lean MEA solution contacts with the flue gas stream to remove CO_2 by absorption/ reaction. The CO_2 rich solution is heated in the regenerator to reverse the reactions and strip the CO_2 gas. The CO_2 lean solution leaves the regenerator. It is cooled and recirculated back to the absorber. A large amount of low-pressure steam is extracted from a steam turbine for the MEA solvent regeneration and reclaim. Cleaned flue gas is transported to a stack. Captured CO_2 is dehumidified and compressed to supercritical conditions for pipeline transport.

Figure 1-10 Simplified Block Flow Diagram for Power Generation with PCC



Source: WorleyParsons

Figure 1-11 Amine-Based Chemical Scrubbing



Source: Ciferno et al. 2009 [40]

Plant output losses from the addition of CO_2 capture and the related compression system represent a relative net efficiency decrease for the plant of approximately 11 to 12 percent [32, 41], almost a third of the plant's net output. Roughly 70 percent of this loss is due to steam extraction from the plant's generating turbine. This steam is used for the solvent regeneration, a process that breaks the bonding of CO_2 to the amine solution and to produce the CO_2 stream for compression. Additionally, approximately 20 percent is lost by the electricity used to drive the compressors. Finally, the electricity used to circulate MEA solvent and drive the flue gas through absorbers accounts for around 10 percent of additional parasitic losses.

The major concerns with MEA and other amine solvents include equipment corrosion in presence of oxygen and other impurities, relatively high solvent degradation rates due to solvent reactions with sulphur dioxide and nitrogen dioxide, and high thermal energy demand for solvent regeneration. These factors generally contribute to large equipment sizes, high solvent consumption and significant energy losses. New or improved solvents with higher CO_2 absorption capacities, faster CO_2 absorption rates, higher degradation resistance, lower corrosiveness and energy use for regeneration are being researched and developed to reduce equipment sizes and capital and operating costs. The following is a summary of MEA based and other solvents considered for chemical solvent absorption of CO_2.

Monoethanolamine (MEA) MEA-based scrubbing process is a commercially available technology. The solvent MEA, a primary amine, reacts with CO_2 at around 40°C and near-to-ambient pressure, which is suitable for post-combustion flue gas. The process consists of an absorber and regenerator, which are connected by a circulation of the MEA solution. In the absorber, the lean MEA solution contacts the flue

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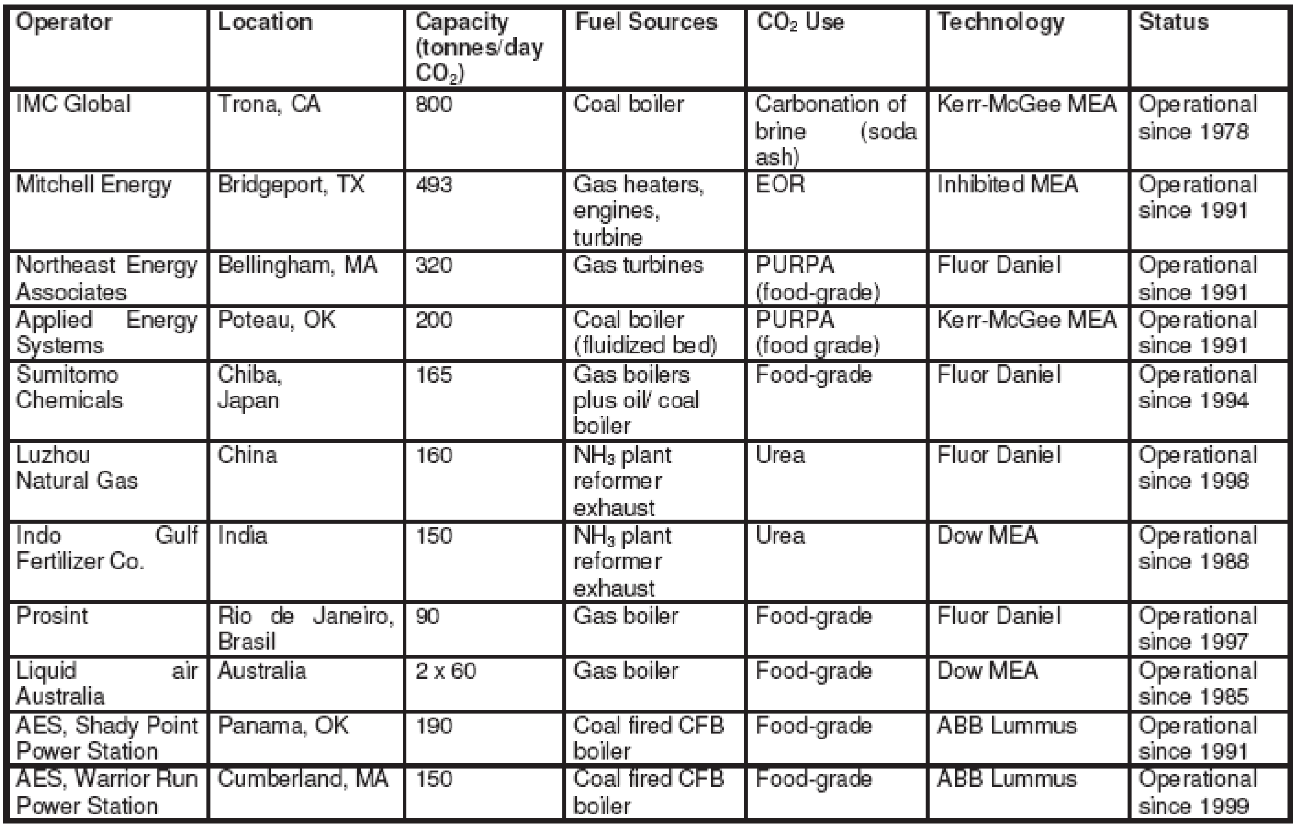
[40] Ciferno, J.P., Fout, T.E., Jones, A.P., Murphy, J.T., 2009: Capturing Carbon from Existing Coal-Fired Power Plants, Chemical Engineering Progress, 105(4), 33-41.

[41] Pulverized Coal Oxycombustion Power Plants, Volume 1: Bituminous Coal to Electricity, Final Report, DOE/NETL 2007/1291, Revision 2, August 2008.

gas stream to remove CO_2 by absorption/reaction. The CO_2-rich solution is heated in the regenerator to reverse the reaction and strip off the CO_2 gas. The CO_2 lean solution then leaves the regenerator. It is cooled and recirculated back to the absorber. Currently, MEA scrubbing technology is a state-of-art option for post-combustion CO_2 capture. Nevertheless, the high heat of reaction with CO_2 and the corrosivity of MEA are drawbacks that have restricted its use. Commercial applications have used formulations of proprietary corrosion inhibitors with MEA, such as the Fluor Econamine FG^{SM} process [42]. A summary of commercial MEA for power plant applications is provided in Figure 1-12.

Table 1-12 Commercial MEA-Based CO_2 Plants[43]



Operator	Location	Capacity (tonnes/day CO_2)	Fuel Sources	CO_2 Use	Technology	Status
IMC Global	Trona, CA	800	Coal boiler	Carbonation of brine (soda ash)	Kerr-McGee MEA	Operational since 1978
Mitchell Energy	Bridgeport, TX	493	Gas heaters, engines, turbine	EOR	Inhibited MEA	Operational since 1991
Northeast Energy Associates	Bellingham, MA	320	Gas turbines	PURPA (food-grade)	Fluor Daniel	Operational since 1991
Applied Energy Systems	Poteau, OK	200	Coal boiler (fluidized bed)	PURPA (food grade)	Kerr-McGee MEA	Operational since 1991
Sumitomo Chemicals	Chiba, Japan	165	Gas boilers plus oil/ coal boiler	Food-grade	Fluor Daniel	Operational since 1994
Luzhou Natural Gas	China	160	NH_3 plant reformer exhaust	Urea	Fluor Daniel	Operational since 1998
Indo Gulf Fertilizer Co.	India	150	NH_3 plant reformer exhaust	Urea	Dow MEA	Operational since 1988
Prosint	Rio de Janeiro, Brasil	90	Gas boiler	Food-grade	Fluor Daniel	Operational since 1997
Liquid air Australia	Australia	2 x 60	Gas boiler	Food-grade	Dow MEA	Operational since 1985
AES, Shady Point Power Station	Panama, OK	190	Coal fired CFB boiler	Food-grade	ABB Lummus	Operational since 1991
AES, Warrior Run Power Station	Cumberland, MA	150	Coal fired CFB boiler	Food-grade	ABB Lummus	Operational since 1999

Digycolamine (DGA®): DGA, another primary amine, is similar to MEA in stability and reactivity, but can be used in much higher concentrations, up to 60-wt%, requiring less energy and circulation, and providing a substantial savings in equipment cost. DGA has a lower vapour pressure and lower inherent corrosivity than MEA. The disadvantages are higher solvent cost and high heat of reaction with CO_2.

KS® series solvents: Kansai Electric Power Company (KEPCO) and Mitsubishi Heavy Industries (MHI) have been developing stearically hindered amines, KS-1, KS-2 and KS-3. Among them, the most commonly known is KS-1. These amines are claimed to have an advantage (as compared to MEA) of a lower circulation rate due to a combination of higher CO_2 loading differential, lower regeneration temperature and lower heat of reaction. KEPCO and MHI reported that the regeneration energy for the KS® series solvents

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[42] Reddy, S., Scherffius, J., Freguia, S. and Roberts, C, "Fluor's Econamine FG PlusSM Technology, An Enhanced Amine-Based CO2 Capture Process", May 2003.

[43] CO2 Capture and Storage, VGB Report on the State of the Art, Published by VGB PowerTech e.V., Essen, 25. August 2004, http://www.vgb.org.

is lower than that of MEA [44]. They are also non-corrosive to carbon steel at 130°C in the presence of oxygen. KS solvent based absorption systems have been utilised on chemical plants for CO_2 separation. The first commercial plant using KS-1 has been in operation since 1999 at Petronas Fertiliser Kedah Sbn Bhd's fertiliser plant in Malaysia [45]. Similar commercial systems are also being used by chemical plants in India. The KS solvent based system for coal-fired power plant application is still in the pilot stage. Hokuriku Electric Power Company has operated a test plant with KS® series solvents treating 50 m^3N/h of flue gas from a coal-fired unit at the Toyama-Shinko power station.

Cansolv: The Cansolv CO_2 Capture System absorbs CO_2 from a feed gas using Cansolv Absorbent DC-101, a patented amine-based regenerable solvent. The recovered CO_2 can be dried, compressed and sequestered without further treatment. The amount of heat added on the regeneration step determines the extent to which the Cansolv absorbent is stripped of CO_2 in the regeneration tower. The regeneration is typically sized to enable bulk removal (90 percent) of the CO_2 in the absorber. However, the process is capable of CO_2 purity to 99.99 percent (dry basis), if required.[46] The Cansolv technology can integrate CO_2 and SO_2 capture in a single absorber, if desired. Cansolv has operated commercial SO_2 capture plants since 2002. It has operated CO_2 pilot plants at several locations, logging over 6,000 hours of operation. The two technologies will come together in an integrated system, in a plant designed to generate 50 tons per day of CO_2, which will start up in 2009.[47]

HTC Purenergy: The HTC Purenergy CO_2 capture process uses a proprietary amine-based HTC solvent to capture CO_2 from industrial flue gases, in particular from fossil fuel power stations. The CO_2 capture efficiency for flue gases from gas-turbine exhaust is claimed to be typically 85 percent. The solvent is tailored to the specific requirements of the customer to reduce the cost of capture. HTC claims that steam consumption is reduced by approximately 50 percent and total solvent losses are by up to 10 times less.[48]

AMP, 2-amino-2-methyl-1-propanol: Using AMP as solvent, results in a substantial reduction in regeneration energy and the overall cost of CO_2 avoided. 37 percent reduction in the avoided cost with a flue gas recycle ratio of 45 percent is achieved using AMP as a solvent compared to 10 percent using MEA solvent.[49]

Chilled Ammonia: The chilled ammonia process for CO_2 capture is being developed by Alstom. It entails scrubbing cooled flue gas with slurry containing dissolved and suspended mix of ammonium carbonate and ammonium bicarbonate in a counter current absorber, similar to ammonia-based SO_2 absorbers. Prior to entering the CO_2 absorber, the flue gas is cooled to approximately 2°C in a direct contact cooler and mechanical chiller, condensing large quantities of water. The chilled flue gas then enters the absorber, where up to 90 percent of the CO_2 is removed. CO_2-rich slurry from the absorber, containing mainly ammonium bicarbonate, is pumped to a high pressure regenerator, where CO_2 is released and separated from other gases. In laboratory tests co-sponsored by Alstom, the Electric Power Research Institute

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[44] Yagi, Y., Mimura, T., Iijima, M., Ishida, K., Yoshiyama, R., Kamijo, T., Yonekawa, T., 2004: "GHGT-7 Improvements of Carbon Dioxide Capture Technology from Flue Gas", presented at the 7th International Conference on Greenhouse Gas Control Technologies, Mitsubishi Heavy Industries, Ltd., http://www.mhi.co.jp/mcec/product/recov_co2/download/pdf/GHGT7_2004%20Improvements.pdf

[45] Kishimoto, S., Hirata, T., Iijima, M., Ohishi, T., Higaki, K., Mitchell, R., 2009: Current Status of MHI's CO2 Recovery Technology and Optimization of CO2 Recovery Plant with a PC Fired Power Plant, Energy Procedia, 1(1), Feb. 2009, 1091-1098, Elsevier Ltd.

[46] Cansolv Technologies Inc. Website: http://www.cansolv.com/en/co2capturedescription.ch2

[47] Shaw, D., "Cansolv CO2 Capture: The Value of Integration", Energy Procedia, Vol 1[1], Feb. 2009, Pages 237-246.

[48] HTC Purenergy Website: http://www.htcenergy.com/co2.html

[49] Mohammad R.M. Abu-Zahraa, Paul H.M. Feronb, Peter J. Jansensc and Earl L.V. Goetheera, "New process concepts for CO2 post-combustion capture process integrated with co-production of hydrogen," April 2009.

(EPRI) and others, the process has demonstrated a potential for capturing more than 90 percent CO_2 at a lower efficiency penalty than other CO_2 capture technologies. The challenges are ammonia volatility and poor kinetics in the absorber. In February 2008 a pilot plant that uses chilled ammonia to capture CO_2 from a 1.7 MW equivalent slip stream of flue gas from a coal-fired boiler was launched by Alstom and EPRI at the We Energies' Pleasant Prairie Power Plant in Wisconsin. A validation plant utilising the chilled ammonia process with CO_2 capture rate of >85% from 20 MWe equivalent flue gas slip stream (54 MWth) has been commissioned in October of 2009 at American Electric Power's (AEP) Mountaineer Plant in West Virginia. [50] The chilled ammonia system currently is not offered commercially; however, AEP indicates that a full scale "project could enter commercial operation as early as 2012."[51]

Aqueous Ammonia: The aqueous ammonia solvent captures CO_2 by reacting ammonia with CO_2 in the flue gas to form ammonium carbonate, and releasing the pure CO_2 stream through the subsequent heating of the ammonium carbonate. Advantages include: (1) low theoretical heat of regeneration; and (2) multi-pollutant control with saleable by-products (ammonium sulphate and ammonium nitrate fertilisers). One technical challenge is degradation of carbonate in the CO_2 absorber leading potentially to ammonia slip in the flue gas. Powerspan's ECO2^{TM} technology has explored this approach at the pilot stage at the First Energy Burger Plant which started operation in October 2008. It processes a 1 MWe equivalent slip stream to capture 20 tonnes per day of CO_2.

1.9 Oxygen Combustion (Oxyfuel Combustion) Capture

Oxygen combustion (oxyfuel combustion) technology facilitates CO_2 capture in two major steps. The first step is accomplished within the oxygen combustion boiler system, in which flue gas with a high CO_2 concentration is produced. The second step includes additional flue gas purification (as required by product CO_2 specification), dehumidification and pressurisation.

The objective of oxygen-fired boiler system is to combust coal in an enriched oxygen environment using oxygen diluted with recycled CO_2. Under these conditions, the primary products of combustion are CO_2 and water. The CO_2 is captured from this exhaust stream by condensing the water. A further flue gas purification step is required that typically employs a low temperature distillation process, in which liquefied CO_2 is separated from the inert gases such as nitrogen and oxygen. The purified CO_2 is then pumped to a supercritical pressure for transportation.

Operation of an oxygen-fired boiler with gas recirculation is essentially the same as an air-fired boiler with the exception that recycled flue gas replaces the primary and secondary air streams. As illustrated in Figure 1-13, the oxygen is injected into primary and secondary streams downstream of the air heater. All oxy-fired system equipment is essentially the same as in an air-fired system except for the gas cooler for condensing water from the gas to be recycled. Since the flue gas is recycled and only high purity oxygen is introduced, the flue gas throughout the system contains a much higher level of CO_2 and very little nitrogen. This increases emissivity, which is essentially offset, in regard to heat transfer, by the change in density and resulting gas velocity.

One other effect is that the concentration of all constituents in the recycled flue gas, if not controlled, will increase as compared to an air-fired unit. This is because the higher the flue gas recycle ratio, the higher the concentration of CO_2, but also other constituents in the flue gas. Hence, for oxygen combustion

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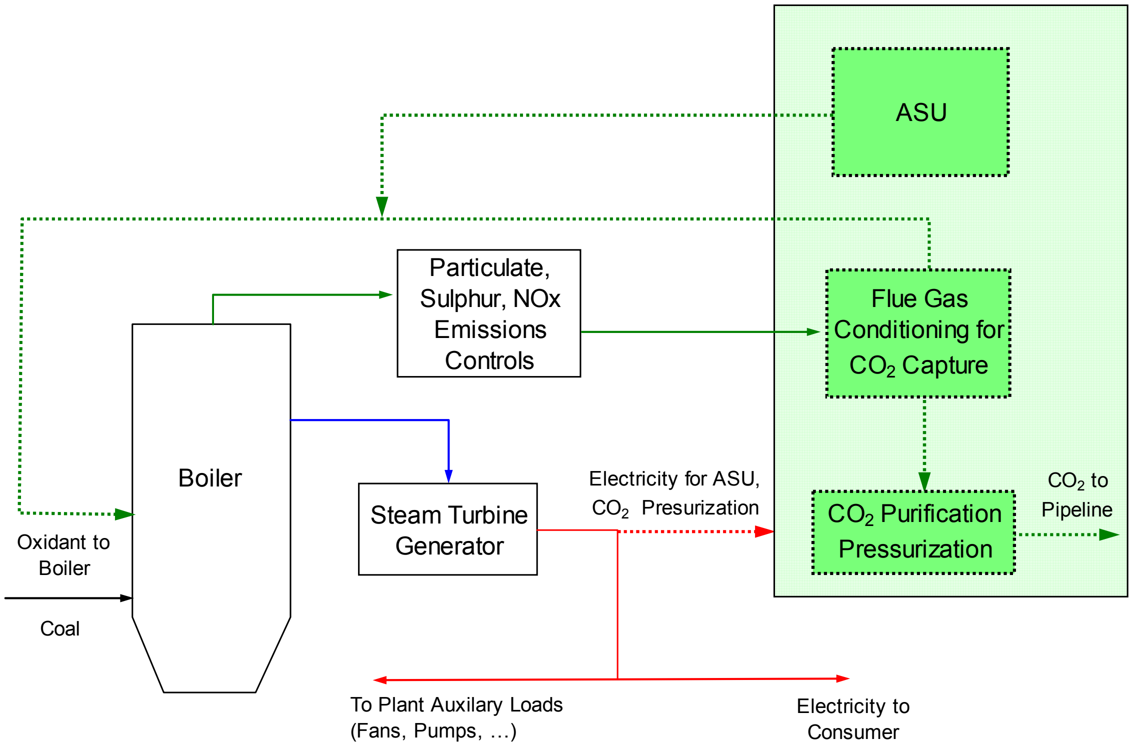
[50] Daniel Duellman, Director of AEP New Generation Engineering, "Update on CO2 capture & Storage Project at AEP's Mountaineer Plant", presented at Air Quality VII Conference on October 26, 2009 in Arlington VA.

[51] AEP Fact Sheet, Alstom's Chilled Ammonia Process for CO2 Capture, 2008: http://www.aep.com/environmental/climatechange/carboncapture/docs/ChilledAmmonia9-22-08.pdf

operation, sulphur dioxide removal efficiency by the flue gas desulphurisation system is governed by the sulphur concentration in the boiler furnace. Similar logic is applicable to the particulate and moisture removal systems, thus allowing increase of CO_2 concentration in the recycled flue gas while maintaining acceptable concentrations of moisture, sulphur compounds and particulates.

Figure 1-13 Simplified Block Flow Diagram for Power Generation with Oxy-combustion Capture



Source: WorleyParsons

Similarly to PCC, net plant efficiency of an oxy-combustion plant is approximately 11 to 12 percent lower as compared to an air blown non-CO_2 capture plant with the same net power output and steam conditions.[41] In the oxy-combustion technology, the decrease in overall plant efficiency is due to the ASU (power consumption). About 65 percent of an oxy-combustion plant net efficiency loss is due to electric power requirements by an ASU. The balance is lost by the electric power required to liquefy CO_2 rich flue gas, purify it to a level comparable to a post-combustion process, and pressurise it to supercritical conditions.

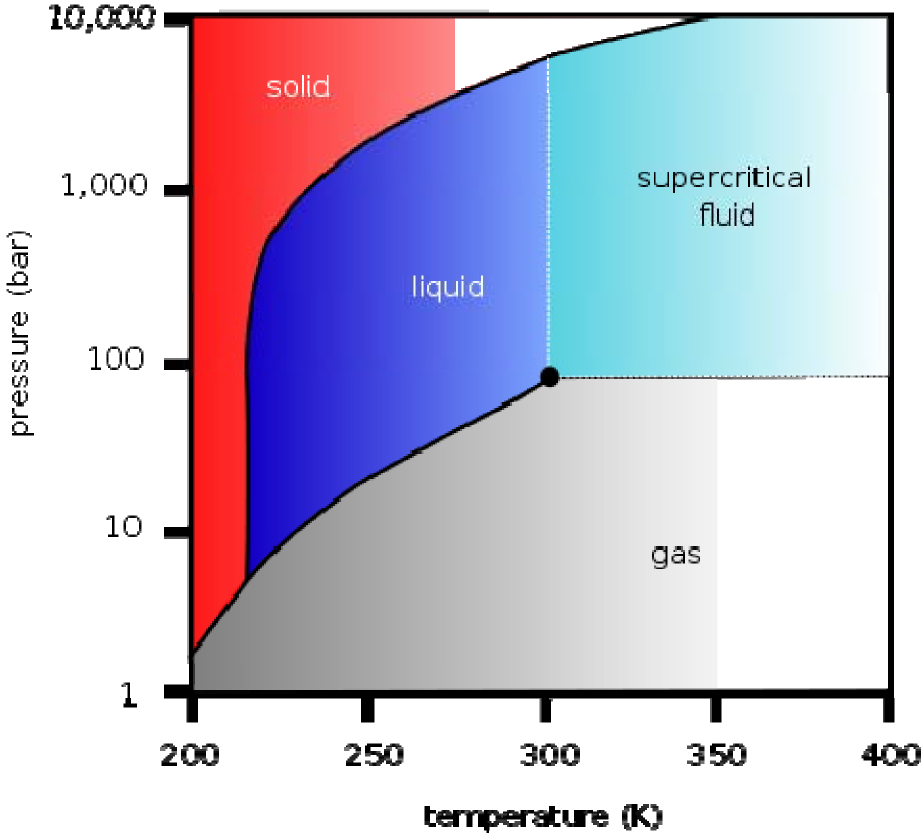
Therefore, all developments that target a decrease in the cost of oxygen will greatly improve the competitiveness of this technology. Such developments include steady improvements of the cryogenic distillation process (leading to a significant cost decrease, even in the past 10 years), as well as investigations of alternative oxygen supply processes such as membranes.

1.10 CO_2 Compression and Dehydration

Prior to pipeline transportation, the CO_2 in the CO_2 removal process must be dried and compressed. CO_2 is conveyed as a liquid or as a dense phase supercritical fluid through increasing the pressure above 7.4 MPa (1073 psi), the critical point pressure. The critical point of CO_2 is 7.38 MPa at 31.1°C (see Figure 1-

14). [52] The typical pipeline operation pressures are in the range of 13.8 – 20.7 MPa (2000-3000 psi) that allows for the CO_2 to be pumped through the pipeline without further compression resulting in energy savings. As the CO_2 travels through the pipeline, the pressure drops. This drop needs to be considered in the initial compression of the CO_2 and recompression stations along the pipeline. Additionally, the impact of elevation changes on the pipeline pressure needs to be taken into account. Dehydration (drying) is required to prevent pipeline corrosion due to the formation of carbonic acid from the CO_2 and water reacting.

Figure 1-14 Phase Diagram for CO_2



Source: U. S. National Institute of Standards and Technology, 2009 [52]

1.10.1 CO_2 Compression

There are two options currently available for the compression of CO_2:

- Compression only
- Compression and Pumping

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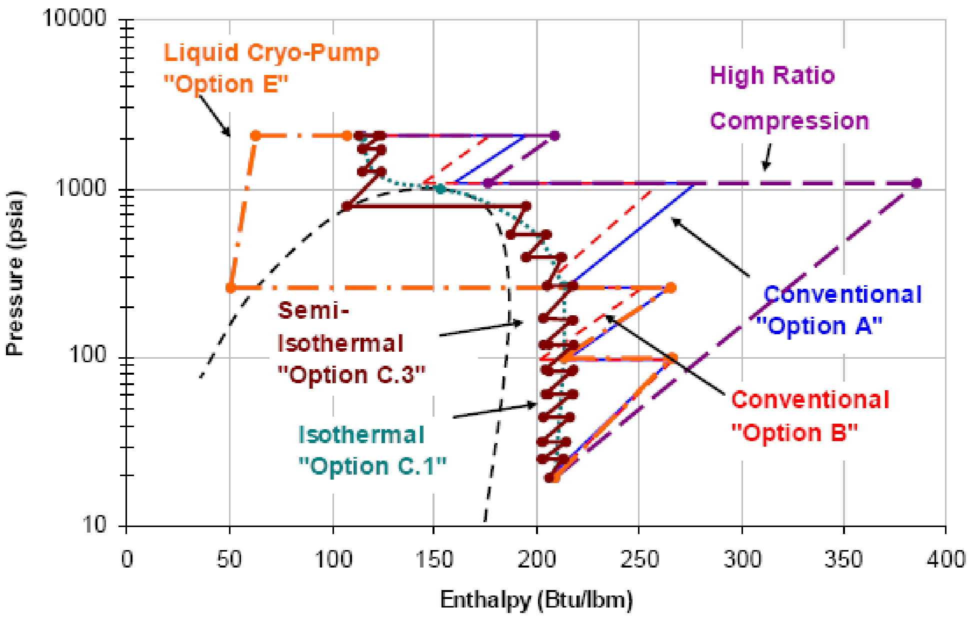
[52] "Phase Change Data for Carbon Dioxide", National Institute of Standards and Technology. http://webbook.nist.gov/cgi/cbook.cgi?ID=C124389&Units=SI&Mask=4#Thermo-Phase

Currently the compression only option is commercial available. The compression and pumping option, considered an advanced compression technology is undergoing development. [53], [54, 55].

Compression Only

In the compression only option, the CO_2 remains as a gas phase throughout the process of achieving the supercritical state. The paths marked "Conventional" and "High Ratio Compression" on the pressure-enthalpy diagram in Figure 1-15 represents compression only processes. Notice that these paths do not pass through the liquid phase region of this diagram as marked by the dashed dome.

Figure 1-15 Comparison of Compression Only and Compression-Pumping Technology Options



Source: Southwest Research Institute; April 2009 [55]

Compressor type selection is dependent on the inlet volumetric flow rate, starting and final pressures, and gas composition. For an amine chemical absorption/regeneration process the starting pressure is approximately 0.18 MPa (26.3 psia) and for Oxy-Fuel CO_2 capture, the starting pressure is approximately 0.10 MPa (15 psia). For IGCC CO_2 capture, depending on the technology chosen, the starting pressure can range from 0.14 to 0.345 MPa (20 to 50 psia).

Three compressor types that may be considered are:

- Reciprocating compressor
- Multi-stage, integrally-geared centrifugal compressor
- Single-shaft, multi-stage centrifugal compressor

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[53] Moore, J.J. Ph.D., "Novel Concepts for the Compression and Transport of Large Volumes of CO2"; Southwest Research Institute; Feb. 2009. http://www.rpsea.org/attachments/contentmanagers/429/SwRI%20CO2%20Compression%20Program-RPSEA2009c%20(2).pdf

[54] Moore, J.J. Ph.D., et. al., "Novel Concepts for the Compression and Transport of Large Volumes of CO2 – Phase II"; Southwest Research Institute; March 2009. http://www.netl.doe.gov/publications/proceedings/09/CO2/pdfs/42650%20Southwest%20Research%20compression%20(Moore)%20mar09.pdf

[55] Moore, J.J. Ph.D., et. al., "Research and Development Needs for Advanced Compression of Large Volumes of Carbon Dioxide"; Southwest Research Institute; April 2009. http://www.nist.gov/eeel/high_megawatt/upload/6_1-Approved-Moore.pdf

Reciprocating compressors are applicable to CO_2 compression. Typically these are more limited in capacity as compared to the centrifugal compressors, such that more trains in parallel may be needed. Due to the nature of their construction and operation, reciprocating compressors generally have lower reliability than centrifugal compressors.

In addition, due to their lubrication, reciprocating compressors have the characteristic of inherent and unavoidable lube oil carryover into the gas. Centrifugal compressors typically have a dry gas seal arrangement and do not have this characteristic. This is of particular concern to a tryethylene glycol (TEG) dehydration system, which is commonly used in this service, due to lube oil causing severe glycol foaming problems and operating upsets in the contactor.

MAN Turbo AG is one of the global suppliers with experience in the area of CO_2 compression to dense phase conditions, having supplied (as Borsig) the compressor at the Great Plains Synfuels Plant for Dakota Gasification Company in Beulah, North Dakota (USA), for the transport of CO_2 to Canada for EOR via the “Weyburn” pipeline. For that application, MAN Turbo supplied three 8-stage integrally-geared compressors.

MAN Turbo claims that, while they are generally interchangeable, the integrally-geared centrifugal compressors have an advantage with relatively high molecular weight gases, such as CO_2, while the in-line centrifugal compressors have an advantage with relatively low molecular weight gases, such as natural gas.

Based on the compressor stage gas inlet temperature, compression configurations can be classified as:

- Isothermal compression with intercoolers after each stage
- Adiabatic compression, with reduced number of intercoolers, or cooling only after final stage that enables compression heat recovery at a relatively high temperature.

In general, isothermal compression requires less compression power, as gas temperature entering each compressor stage is maintained constant and relatively low by the means of interstage cooling. In adiabatic compression gas temperatures could reach 200°C, making adiabatic compression a possible choice for systems that would benefit from compression heat recovery for feedwater preheating, or steam generation.

Compression and Pumping

In the compression and pumping process CO_2 stream is compressed, dehydrated, chilled and then pumped to a required pressure as illustrated by the path marked “Liquid Cryo-Pump-Option E” in Figure 1-15. The compression and pumping system requires energy for low pressure compression, chilling and pumping. Combined compression and pumping processes are reported to require less power as compared to compression only. However, in other publications the compression and pumping option is shown to require more power then compression only, depending on system configuration. The presence of impurities in product CO_2 stream, such as nitrogen will increase the energy requirement for chilling at a given pressure. Thus the compression plus pumping option is typically utilised in conjunction with CO_2 low temperature purification system. The most likely application is the oxyfuel process, which could produce product stream with CO_2 purity less than 90% and containing 2-3% of O_2. Product CO_2 stream needs to be distilled at a low temperature to separate non-condensable gases. CO_2 purification is accomplished in low temperature distiller, in which liquid CO_2 is collected on the bottom of the distiller column and then pumped to a specified pressure.

Dehydration Options

During staged compression of the captured CO_2 product stream, the moisture content is first reduced by cooling the gas below its dew point and knocking out water, and finally by dehydration. The main processes which are typically utilised for gas dehydration use glycol or a solid absorbent (e.g. mole sieve). A typical range of applications for common gas dehydration processes is presented below:

Table 1.16: Range of Applications for Dehydration Processes

Dehydration Process	Final Moisture Content
Mole Sieve	<-260°F Hydrate point; Bone Dry for LNG unit
Tri-Ethylene Glycol (TEG)	-45°F Hydrate Point ~0.5 Lb H2O/10^6 SCF

TEG is the most widely used fluid in dehydration absorption systems, since it offers the best combination of ease of operation and economics. It is the most common dehydration method used for natural gas.

Dehydration by TEG contacting is the standard method of achieving the CO_2 transport and sequestration moisture specification. Although not usually required, TEG dehydration can achieve the near-bone-dry specification of 20 ppm by volume moisture content (1 lb/MMscf), equivalent to a water dew point of -55°C (-67°F). More typically, the moisture specification, as used by Kinder Morgan for EOR, is 633 ppmv (30 lb/MMscf), equivalent to a water dew point of -22°C (-8°F), for reasons of corrosion. [[56]]

Mole sieve has a higher life-cycle-cost than glycol and is usually used when completely dried gas is required, such as low temperature liquefaction utilised for CO_2 compression and pumping.

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[56] Havens, K., “CO2 Transportation and EOR”, Kinder Morgan CO2 Company, Presented at INGAA, Houston, Texas, USA; September 21, 2007. http://www.ingaa.org/File.aspx?id=5546

Attachment 2
Carbon Capture Case Studies

2. CO_2 CAPTURE CASE STUDIES REPORT

2.1 Introduction

The objective of this study is to assess technical feasibility of the following:

- Study Case 1 - Retrofit of an existing natural gas combined cycle (NGCC) unit with CO_2 capture and CO_2 compression/dehydration system sized for 1,000,000 tonnes of CO_2 per annum, and
- Study Case 2 - An addition of a compression/dehydration system sized for 4,000,000 tonnes per annum of CO_2 at a future planned urea production facility.

Two study cases are evaluated and presented in this report. The report displays a summary of results of CO_2 capture technical analysis, establishes study evaluation basis, and provides descriptions of CO_2 capture/compression systems and preliminary major equipment sizing.

2.1.1 Approach

This analysis represents a broad engineering assessment for the study cases that provides conceptual level information to support system planning studies, preliminary cost and economic assessments, and plant site evaluations. The conceptual design engineering presented in this report lays the technical foundation for selecting design concepts and equipment, and defines the key design features, functional systems and structures, system and equipment design constraints, plant performance, and plant costs. This report focuses on developing the preliminary technical information to support project planning and analysis. As the projects evolve, a follow-on detailed design process will be required to facilitate continued feasibility assessment, permitting/licensing, equipment procurement, construction, and operation of the new facility.

2.2 Study Cases

Two design cases were evaluated and are presented in this report. A summary of the design cases is presented in Table 2-1.

Table 2-1 : Summary of Study Cases

Case	Facility	Facility Status	Project Type	Location	CO_2 Captured	CO_2 Captured from Additional Source	CO_2 Pipeline pressure
1	NGCC	Existing	Retrofit	North island	10^6 T/y	3*10^5 T/y (Note)	183 barg
2	Lignite Processing Plant	Future	Addition	South Island	4*10^6 T/y	0 T/y	190 barg

Note: Case study 1 is assumed to include an additional 300,000 tonne per annum capacity for a carbon capture from an upstream fertiliser or gas treatment plant

2.2.1 Case 1 – NGCC Retrofit

The Case 1 design scenario considers the retrofit of an existing natural gas combined cycle (NGCC) plant with a post-combustion CO_2 capture system. The candidate NGCC plant design for this study is assumed to be similar to a Stratford-size Power Station owned by Contact Energy Ltd., and located on New Zealand North Island [57]. The CO_2 capture plant is designed to capture 1,000,000 tonnes of CO_2 per

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[57] Rolf Kehlhofer, Bert Rukes, Frank Hannemann, Franz Stirnimann, "Combined-Cycle Gas Steam Turbine Power Plants", 3rd Edition, PennWell.

annum. This amount corresponds approximately to a fully loaded pre-retrofit Alstom KA-26-1 gas turbine combined cycle unit operating at an annual capacity factor of 80%.

Site Description

The assumed site conditions are based on conditions at the Stratford Power Station and are presented in Table 2-2.

Table 2-2: Site Ambient Conditions

Parameter	Units	Value
Elevation above mean sea level (AMSL)	meter	270
Barometric Pressure	mbar	981
Design Ambient DBT	°C	11.6
Design Ambient Relative Humidity,	%	84
Cooling type		Evaporative Cooling tower

DBT – dry bulb temperature

Natural gas is the main fuel for both the existing NGCC plant (without CO_2 capture) and for the retrofitted case for the NGCC plant with CO_2 capture. The natural gas composition is assumed based on WorleyParsons previous project experience in Australia and presented in Table 2-3.

Table 2-3: Natural Gas Analysis

Component	Chemical Formula	Volume %
Methane	CH_4	87.6344
Propane	C_3H_8	2.7554
n-Butane	C_4H_{10}	0.9079
Pentane	C_5H_{12}	0.2639
Hexane	C_6H_{14}	0.0032
Heptane	C_7H_{16}	0.0211
Carbon Dioxide	CO_2	5.6903
Nitrogen	N_2	2.7239
Total		100.0
Heating value	**LHV**	**HHV**
kJ/kg	41,195	45,591
Btu/scf	902.3	998.6

Plant Configuration

The plant configuration is based on an Alstom KA-26-1 combined cycle design with a nominal gross power rating of 360 MWe. The existing plant configuration specifics are summarised in Table 2-4.

Table 2-4: Candidate Plant Description

Parameter	Description
Plant Configuration	KA 26-1
Arrangement	1x1 Configuration (1 GTG + 1 HRSG + 1 x STG)
Gas Turbine Make & Model	Alstom GT-26
Fuel	• Only natural gas firing • No Dual Fuel considered for the study
Steam Turbine	HP steam 103 bar/ 568°C RH steam 24 bar/ 568°C
Main Condensing by	Evaporative Cooling Tower
Base Load / Cycling Plant	Base Load
Capacity Factor	80%
Duct Firing per HRSG	None

The estimated performance of the Alstom KP-26 gas turbine and exhaust flue gas characteristics are presented in Table 2-5.

Table 2-5: Gas Turbine/HRSG Exhaust Parameters

Parameter	Units	Value
GTG power output	kWe	252
LHV Heat Rate	kJ/kWhr	9848
Exhaust Mass Flow	kg/hr	1,959,500
Exhaust Temperature	°C	647
Back pressure at GT exhaust (with HRSG)	mm of H_2O (gauge)	355.6
Composition	**% Volume**	**% wt**
Ar	0.89	1.25
CO_2	4.68	7.26
H_2O	9.2	5.84
O_2	11.22	12.64
N_2	74.01	73.35

Note: at design ambient dry bulb temperature of 11.6°C.

CO_2 Reduction Target

The Case 1 evaluation will target to achieve a total CO_2 capture of 1,000,000 tonnes per annum. In this study, it is assumed that CO_2 will be separated from the HRSG exhaust using an advanced chemical absorption process based on a monoethanol amine (MEA) solvent (such as the Fluor Econamine FG Plus^{SM}). The HRSG exhaust parameters are listed in Table 2-5: . Captured CO_2 will be conditioned, compressed and then delivered to the transport pipeline at the plant boundary as a supercritical fluid. The assumed pipeline CO_2 specification is presented in Table 2-6.

Table 2-6: Product CO_2 Specification

Parameter	Units	Value
Pressure @ Plant Boundary	barg	183
CO_2, minimum purity	% Volume	99
H_2O, max	ppmv	100

System Description

The block flow diagram of the retrofitted plant is presented in Table 2-7 and heat and mass balance (HMB) is presented in Table 2-8.

An advanced monoethanol amine (MEA) solvent based chemical absorption system is utilised to capture CO_2 from the gas turbine exhaust. The CO_2 capture plant is designed to be independent of the base NGCC plant for steam demand and almost independent for electric power demand (including CO_2 capture and compression processes). The CO_2 compressor is powered by a gas turbine mechanical drive. Heat from the gas turbine drive exhaust is recovered in a once through steam generator (OTSG) to generate steam for the MEA solvent regeneration (Stream 12). The balance of the MEA system steam demand is met by a new auxiliary steam generator (Stream 11). The auxiliary steam generator is a duct burner-fired HRSG installed between the base plant HRSG and the CO_2 capture plant. Process steam condensate from MEA re-boiler (Stream 71) is routed back to the base plant HRSG / steam cycle system. The CO_2 capture and compression plant cooling load is rejected to a new evaporative cooling tower (Streams 40, 41, 76, 77, 96, and 97). Make-up water for the new cooling tower is sourced from the base plant water system. Except for the CO_2 compressor, all other auxiliary loads associated with the CO_2 Capture plant will depend upon use of electric power from the base NGCC plant.

A slip stream of the base plant HRSG exhaust flue gas equivalent to 10^6 tpa of CO_2 (Stream 31) is diverted to the auxiliary steam generator. The balance of the flue gas is transported to a new stack via new bypass flue gas ducts (Stream 30). This configuration should permit the retrofitted unit continuous operation in an intermittent load while supporting grid area regulation. The flue gas in Stream 31 contains approximately 11% O_2, which is sufficient to support combustion in the duct burner of the auxiliary HRSG. The auxiliary steam generator exhaust flue gas (Stream 32) is cooled in a direct contact cooler (DCC) (Stream 50), and its pressure is boosted (Stream 56). The flue gas from the booster fan enters the bottom of the MEA absorber tower where it is contacted counter-currently with lean MEA solvent. The lean MEA solvent enters the top of the column and heats up gradually as CO_2 is absorbed. The solvent, enriched with CO_2, is pre-heated by heat exchange with lean MEA solvent from stripping column and enters near the top of the regenerator column. In the regenerator, through the addition of heat, the absorption reaction is reversed and the CO_2 is released from the CO_2 rich solvent. The re-boiler is where the heat energy from steam is added to the process to heat up the solvent and de-sorb the CO_2. The effluent CO_2 from the regenerator along with water vapour and a limited amount of solvent vapour is cooled by water in the reflux condenser, where most of the water vapour and solvent vapour are condensed. The CO_2 is then separated from the water in the reflux drum and directed to the CO_2 compression section, while recovered water and MEA solvent is sent back to the regenerator. The top sections of both the absorber and regenerator have a wash zone designed to minimize the MEA losses due to mechanical entrainment and evaporation. Approximately 85% of the CO_2 in the MEA feed gas is captured. The treated flue gas (Stream 60) is vented via the plant stack.

The CO_2 recovered from the MEA system (Stream 80) is compressed in a multiple-stage, intercooled compressor and dehydrated to meet the CO_2 pipeline specification. The CO_2 compression and dehydration system is sized to process an additional CO_2 stream imported from a neighboring urea plant (Stream 81). Most of the water in the wet CO_2 stream is knocked out during compression and is removed from intermediate knockout drums. A CO_2 dehydration unit is located downstream from the compressor's fifth stage to meet the water specification in the CO_2 product. The CO_2 stream is dehydrated with triethylene glycol (TEG). Virtually moisture-free supercritical CO_2 stream is then ready for pipeline transportation (Stream 90).

Figure 2-7: Retrofitted Plant Block Flow Diagram (Case 1)

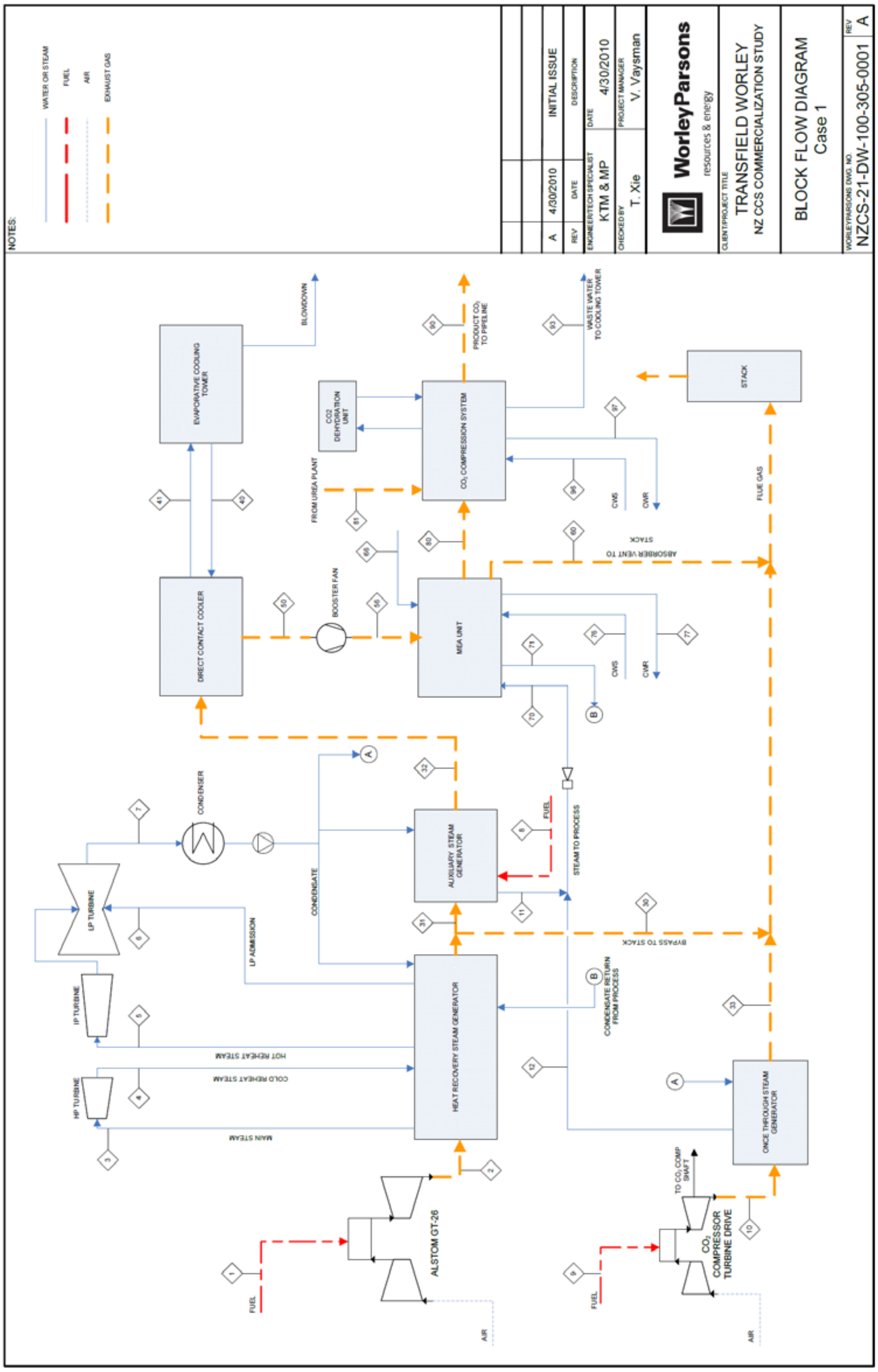

Table 2-8: Retrofitted Plant HMB (Case 1)

TRANSFIELD WORLEY - NZ CCS COMMERCIALIZATION STUDY
Heat and Material Balance - Case 1
STREAM TABLE (SI UNITS)

STREAM		01	02	03	04	05	06	07	08	09	10
DESCRIPTION	Units	GT-26 Fuel Inlet	GT-26 Exhaust Flow	Steam Turbine Main Throttle Inlet	Steam Turbine Cold Reheat (1)	Steam Turbine Hot Reheat	Steam Turbine LP Admission	Steam Turbine Exhaust	Aux Steam Generator Duct Burner Fuel Inlet	CO2 Compressor Driven Turbine Fuel Inlet	CO2 Compressor Driven Turbine Exhaust Flow
CCS Case 1											
Flow	kg/hr	58,016	1,959,521	274,134	274,134	299,998	26,506	326,504	10,634	4,642	92,760
Temperature	°C		647	568	369	568	286	39			379
Pressure	bar			103	27	24	4.8	0.070			
Enthalpy	kJ/kg			3,541	3,168	3,614	3,037	2,500			
STREAM		11	12								
DESCRIPTION	Units	Process Steam from Auxiliary Steam Generator	Process Steam from OTSG								
Flow	kg/hr	181,729	9,998								
Temperature	°C	184	184								
Pressure	bar	5.7	5.7								
Enthalpy	kJ/kg	2,817	2,817								

Note: The zero for the enthalpy function in this table is determined by the ASME/NIST conventions that the entropy and internal energy functions are zero for the saturated liquid at the triple point.

Transfield Worley - New Zealand CCS Commercialization Study

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Heat and Material Balance - Case 1 (SI UNITS)

HRSG-Direct Contact Cooler

NZCS-21-DW-100-305-0001

PFD Stream No.	30		31		32		33		40		41		50		56	
DESCRIPTION	HRSG Exhaust Bypassed to Stack		HRSG Exhaust to Auxiliary Fired HRSG		Auxiliary Steam Generator Exhaust to Direct Contact Cooler		CO2 Compressor Turbine Drive HRSG Exhaust to Stack		Cooling Water from Wet Cooling Tower		Hot Water to Wet Cooling Tower		Cooled Flue Gas Exhaust to Booster Fan		Boosted Flue Gas Exhaust to MEA Unit	
V&L Mixture Components	kgmol/hr	Mol %	kgmol/hr	Mol %	kgmol/hr	Mol %	kgmol/hr	Mol %	kgmol/hr	Mol %	kgmol/hr	Mol %	kgmol/hr	Mol %	kgmol/hr	Mol %
Ar	16	0.88	595	0.88	595	0.87	28	0.85	0	0.00	0	0.00	595	0.94	595	0.94
CO_2	83	4.68	3,148	4.68	3,816	5.61	258	7.79	3	0.00	4	0.00	3,816	6.06	3,816	6.06
H_2O (and ionic species)	168	9.51	6,401	9.51	7,694	11.32	499	15.10	198,921	100.00	203,924	100.00	2,691	4.27	2,691	4.27
N_2	1,302	73.76	49,663	73.76	49,658	73.06	2,365	71.49	1	0.00	1	0.00	49,658	78.87	49,658	78.87
O_2	197	11.17	7,520	11.17	6,201	9.12	158	4.77	0	0.00	0	0.00	6,201	9.85	6,201	9.85
TOTAL	1,765	100.00	67,326	100.00	67,965	100.00	3,308	100.00	198,926	100.00	203,929	100.00	62,961	100.00	62,961	100.00
V&L Mixture Components	kg/hr	Mass %	kg/hr	Mass %	kg/hr	Mass %	kg/hr	Mass %	kg/hr	Mass %	kg/hr	Mass %	kg/hr	Mass %	kg/hr	Mass %
Ar	623	1.24	23,755	1.24	23,755	1.24	1,130	1.22	1	0.00	1	0.00	23,755	1.30	23,755	1.30
CO_2	3,632	7.26	138,561	7.26	167,945	8.75	11,346	12.23	153	0.00	156	0.00	167,941	9.18	167,941	9.18
H_2O (and ionic species)	3,023	6.04	115,313	6.04	138,612	7.22	8,998	9.70	3,583,612	99.99	3,673,755	99.99	48,471	2.65	48,471	2.65
N_2	36,469	72.86	1,391,222	72.86	1,391,106	72.46	66,242	71.41	35	0.00	36	0.00	1,391,101	76.03	1,391,101	76.03
O_2	6,308	12.60	240,623	12.60	198,438	10.34	5,044	5.44	9	0.00	9	0.00	198,438	10.85	198,438	10.85
TOTAL	50,054	100.00	1,909,474	100.00	1,919,857	100.00	92,760	100.00	3,583,810	100.00	3,673,958	100.00	1,829,707	100.00	1,829,707	100.00
V&L Mixture Properties																
Vapor Frac	1.00		1.00		1.00		0.00		0.00		0.00		1.00		1.00	
Temperature, C	130		130		130		127		17		53		29		44	
Pressure, bar	1.0		1.0		1.0		1.0		1.1		2.1		1.0		1.1	
Enthalpy, kJ/kg	-1,639		-1,639		-1,639		-1,640		-15,898		-15,746		-1,172		-1,157	
Density, kg/m3	0.83		0.83		0.83		0.80		998.80		986.46		1.12		1.20	
Molecular Weight	28.25		28.25		28.25		28.04		18.02		18.02		29.06		29.06	

Note: In this table the enthalpy reference point is natural state of the constituent elements in their standard states at 1 atm and 25°C.

Transfield Worley - New Zealand CCS Commercialization Study
Heat and Material Balance - Case 1 (SI UNITS)
MEA Unit
NZCS-21-DW-100-305-0001

5/6/2010

PFD Stream No.	60		66		70		71		76		77		80			
DESCRIPTION	Treated Flue Gas Exhaust to Stack		Makeup Water to MEA Unit		LP Steam from Steam Cycle		LP Steam Condensate to Steam Cycle		CWS to MEA Unit		CWR from MEA Unit		Recovered CO_2 to CO_2 Compression			
V&L Mixture Components	kgmol/hr	Mol %	kgmol/hr	Mol %	kgmol/hr	Mol %	kgmol/hr	Mol %	kgmol/hr	Mol %	kgmol/hr	Mol %	kgmol/hr	Mol %	kgmol/hr	Mol %
Ar	595	0.92	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00		
CO_2	563	0.87	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	3,253	98.09		
H_2O (and ionic species)	7,963	12.25	5,334	100.00	10,842	100.00	10,842	100.00	182,542	100.00	182,542	100.00	62	1.87		
N_2	49,658	76.42	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.03		
O_2	6,201	9.54	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.01		
TOTAL	64,979	100.00	5,334	100.00	10,842	100.00	10,842	100.00	182,542	100.00	182,542	100.00	3,317	100.00		
V&L Mixture Components	kg/hr	Mass %	kg/hr	Mass %	kg/hr	Mass %	kg/hr	Mass %	kg/hr	Mass %	kg/hr	Mass %	kg/hr	Mass %	kg/hr	Mass %
Ar	23,754	1.33	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.00		
CO_2	24,756	1.39	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	143,186	99.20		
H_2O (and ionic species)	143,451	8.05	96,089	100.00	195,325	100.00	195,325	100.00	3,288,549	100.00	3,288,549	100.00	1,116	0.77		
N_2	1,391,074	78.09	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	29	0.02		
O_2	198,430	11.14	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	8	0.01		
TOTAL	1,781,465	100.00	96,089	100.00	195,325	100.00	195,325	100.00	3,288,549	100.00	3,288,549	100.00	144,340	100.00		
V&L Mixture Properties																
Vapor Frac	1.00		0.00		1.00		0.00		0.00		0.00		1.00			
Temperature, C	50		38		159		142		17		28		26			
Pressure, bar	1.0		2.1		4.5		4.1		6.2		4.8		1.8			
Enthalpy, kJ/kg	-1,178		-15,988		-13,204		-15,373		-15,898		-15,851		-3,858			
Density, kg/m3	1.04		981.55		2.33		924.06		999.10		996.43		3.15			
Molecular Weight	27.42		18.02		18.02		18.02		18.02		18.02		43.52			

Note: In this table the enthalpy reference point is natural state of the constituent elements in their standard states at 1 atm and 25°C.

Transfield Worley - New Zealand CCS Commercialization Study
Heat and Material Balance - Case 1 (SI UNITS)
CO_2 Compression & Dehydration
NZCS-21-DW-100-305-0001

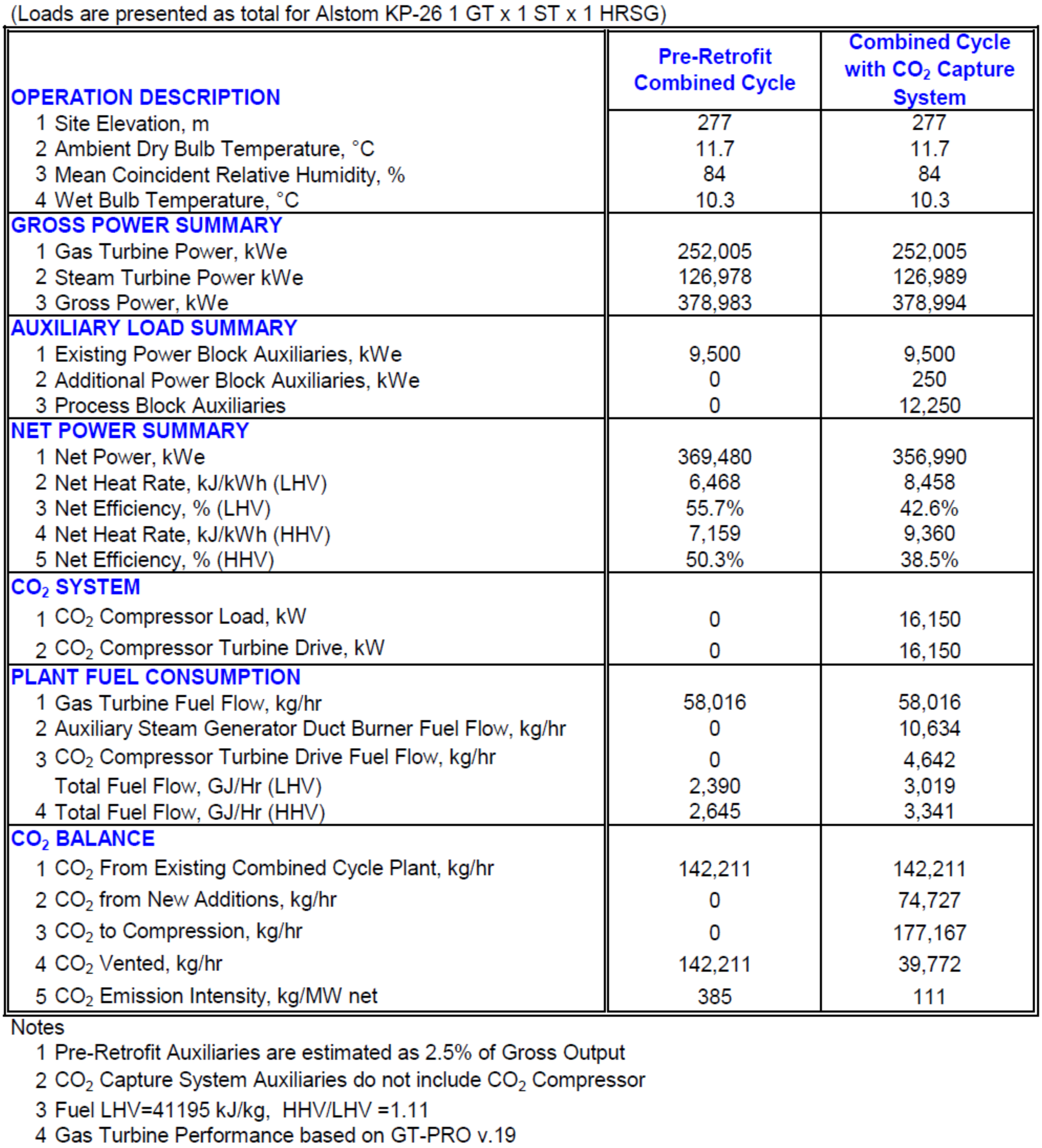
5/6/2010

PFD Stream No.	81		90		93		96		97							
DESCRIPTION	Urea CO_2 to Compression		Product CO_2 to Pipeline		Waste Water to Treatment		CWS to CO_2 Compression Intercooling		CWR from CO_2 Compression Intercooling							
V&L Mixture Components	kgmol/hr	Mol %	kgmol/hr	Mol %	kgmol/hr	Mol %	kgmol/hr	Mol %	kgmol/hr	Mol %	kgmol/hr	Mol %	kgmol/hr	Mol %	kgmol/hr	Mol %
Ar	1	0.10	1	0.02	0	0.00	0	0.00	0	0.00						
CO_2	772	99.09	4,026	99.79	0	0.19	0	0.00	0	0.00						
H_2O (and ionic species)	0	0.00	0	0.01	56	99.81	125,291	100.00	125,291	100.00						
N_2	6	0.81	7	0.18	0	0.00	0	0.00	0	0.00						
O_2	0	0.00	0	0.01	0	0.00	0	0.00	0	0.00						
TOTAL	780	100.00	4,034	100.00	56	100.00	125,291	100.00	125,291	100.00						
V&L Mixture Components	kg/hr	Mass %	kg/hr	Mass %	kg/hr	Mass %	kg/hr	Mass %	kg/hr	Mass %	kg/hr	Mass %	kg/hr	Mass %	kg/hr	Mass %
Ar	32	0.09	33	0.02	0	0.00	0	0.00	0	0.00						
CO_2	33,997	99.39	177,167	99.86	5	0.46	0	0.00	0	0.00						
H_2O (and ionic species)	0	0.00	4	0.00	1,011	99.54	2,257,154	100.00	2,257,154	100.00						
N_2	177	0.52	206	0.12	0	0.00	0	0.00	0	0.00						
O_2	0	0.00	8	0.00	0	0.00	0	0.00	0	0.00						
TOTAL	34,206	100.00	177,418	100.00	1,016	100.00	2,257,154	100.00	2,257,154	100.00						
V&L Mixture Properties																
Vapor Frac	1.00		---		0.00		0.00		0.00							
Temperature, C	15		26		25		17		28							
Pressure, bar	1.4		184.0		3.2		6.2		4.8							
Enthalpy, kJ/kg	-8,888		-9,193		-16,022		-15,898		-15,851							
Density, kg/m3	2.55		---		560.29		999.10		996.43							
Molecular Weight	43.36		43.98		18.06		18.02		18.02							

Note: In this table the enthalpy reference point is natural state of the constituent elements in their standard states at 1 atm and 25°C.

Major impacts on the retrofitted unit performance are summarized in Table 2-9.

Table 2-9: Plant Performance Summary (Case 1)



(Loads are presented as total for Alstom KP-26 1 GT x 1 ST x 1 HRSG)

OPERATION DESCRIPTION	**Pre-Retrofit Combined Cycle**	**Combined Cycle with CO_2 Capture System**
1 Site Elevation, m	277	277
2 Ambient Dry Bulb Temperature, °C	11.7	11.7
3 Mean Coincident Relative Humidity, %	84	84
4 Wet Bulb Temperature, °C	10.3	10.3
GROSS POWER SUMMARY		
1 Gas Turbine Power, kWe	252,005	252,005
2 Steam Turbine Power kWe	126,978	126,989
3 Gross Power, kWe	378,983	378,994
AUXILIARY LOAD SUMMARY		
1 Existing Power Block Auxiliaries, kWe	9,500	9,500
2 Additional Power Block Auxiliaries, kWe	0	250
3 Process Block Auxiliaries	0	12,250
NET POWER SUMMARY		
1 Net Power, kWe	369,480	356,990
2 Net Heat Rate, kJ/kWh (LHV)	6,468	8,458
3 Net Efficiency, % (LHV)	55.7%	42.6%
4 Net Heat Rate, kJ/kWh (HHV)	7,159	9,360
5 Net Efficiency, % (HHV)	50.3%	38.5%
CO_2 SYSTEM		
1 CO_2 Compressor Load, kW	0	16,150
2 CO_2 Compressor Turbine Drive, kW	0	16,150
PLANT FUEL CONSUMPTION		
1 Gas Turbine Fuel Flow, kg/hr	58,016	58,016
2 Auxiliary Steam Generator Duct Burner Fuel Flow, kg/hr	0	10,634
3 CO_2 Compressor Turbine Drive Fuel Flow, kg/hr	0	4,642
Total Fuel Flow, GJ/Hr (LHV)	2,390	3,019
4 Total Fuel Flow, GJ/Hr (HHV)	2,645	3,341
CO_2 BALANCE		
1 CO_2 From Existing Combined Cycle Plant, kg/hr	142,211	142,211
2 CO_2 from New Additions, kg/hr	0	74,727
3 CO_2 to Compression, kg/hr	0	177,167
4 CO_2 Vented, kg/hr	142,211	39,772
5 CO_2 Emission Intensity, kg/MW net	385	111

Notes

1 Pre-Retrofit Auxiliaries are estimated as 2.5% of Gross Output

2 CO_2 Capture System Auxiliaries do not include CO_2 Compressor

3 Fuel LHV=41195 kJ/kg, HHV/LHV =1.11

4 Gas Turbine Performance based on GT-PRO v.19

A list of the new major equipment is presented in Table 2-10.

Table 2-10: Major Equipment List (Case 1)

ITEM	EQUIPMENT SCOPE	QTY	CAPACITY BASIS/DATA	REMARKS
COMBUSTION TURBINE EQUIPMENT AND AUXILIARIES				
	CO_2 COMPRESSOR TURBINE DRIVE	1	**OUTPUT:** 17,400 kW (ISO Rating) **NO_X EMISSIONS:** 85 mg/NM^3 @ 15% O2 (gas).	SIEMENS SGT-500
AUXILIARY STEAM GENERATOR EQUIPMENT AND AUXILIARIES				
	AUXILIARY STEAM GENERATOR	1	**LP:** 182,000 kg/hr, 5.86 bara, 186°C **DUTY:** 485 GJ/hr	One pressure level,
	INLET DUCTWORK AND EXPANSION JOINT	1		Supplied by boiler vendor.
	OUTLET DUCTWORK AND EXPANSION JOINT	1		Supplied by boiler vendor.
	ECONOMIZER BYPASS AND RECIRCULATION SYSTEM	1		Supplied by boiler vendor.
	EXHAUST STACK AND DAMPERS	1		Supplied by boiler vendor.
	EXHAUST STACK SILENCER	1		Supplied by boiler vendor
	CONTINUOUS BLOWDOWN TANK	1		Supplied by boiler vendor.
	BLOWDOWN SUMP DRAIN PUMPS	2		
ONCE THROUGH STEAM GENERATOR				
	ONCE THROUGH STEAM GENERATOR	1	**STEAM FLOW:** 10,450 kg/hr, 5.86 bara, 186°C **DUTY:** 27.5 MMBH	
HEAT CYCLE				
	CONDENSATE BOOSTER PUMPS TO CO_2 COMPRESSOR TURBINE DRIVE HEAT RECOVERY UNIT	1	**FLOW:** 11 m^3/hr **TOTAL HEAD:** 186 m **POWER:**. 10 kW	1 x 100%. Centrifugal, vertical turbine can-type, motor-driven.
	CONDENSATE RETURN BOOSTER PUMP FROM REBOILER TO COMBINED CYCLE	1	**FLOW:** 210 m^3/hr **TOTAL HEAD:** 104 m **POWER:**. 90 kW	1 x 100%. Centrifugal, horizontal can-type, motor-driven.

ITEM	EQUIPMENT SCOPE	QTY	CAPACITY BASIS/DATA	REMARKS
	CONDENSATE BOOSTER PUMP TO AUXILIARY HRSG	1	**FLOW:** 195 m^3/hr **TOTAL HEAD:** 186 m **POWER:** 145 kW	1 x 100%. Centrifugal, vertical turbine can-type, motor-driven.
MEA CO2 REMOVAL SYSTEM				
	DIRECT CONTACT COOLER	1	**FLOW:** 2.3 MMm3/hr @ .97 bara and 130 C **DUTY:** 1.64 MMm^3/hr cooling water	
	FLUE GAS BOOSTER FAN	1	**POWER:** 7700 kW **FLOW:** 1.53 MMm^3/hr Flue Gas	Centrifugal Fan
	MEA CO$_2$ ABSORBER	1	**FLOW:** 1.53MMm^3/hr Flue Gas @ 52 C and 1.09 bara	Packed Column with Inter-Stage Cooler Includes MEA wash section.
	ABSORBER INTERCOOLER	1	**DUTY**: 23.2 GJ/hr **FLOW:** 993 m^3/hr MEA Solution	Includes pump skid
	RICH SOLVENT PUMP	2	**HEAD:** 17 TDH **POWER:** 200 kW **FLOW:** 3,055 m^3/hr solution	1 spare
	LINE-RICH EXCHANGER	1	**DUTY:** 342 GJ/hr	
	FLASH PREHEATER	1	**DUTY:** 131 GJ/hr	
	STRIPPER COLUMN	1	**FLOW:** 1630 m^3/hr solution	Packed Column
	REFLUX CONDENSER	1	**DUTY:** 100 GJ/hr @ 78 F	
	REFLUX DRUM	1	**FLOW:** 45745 m^3/hr CO$_2$ Product (144,341 kg/hr) 26 C and 1.79 bara	Includes pump skid
	THERMOSYPHON REBOILER	1	**DUTY:** 396 GJ/hr	
	SOLVENT RECLAIMER PACKAGE	1		
	LEAN SOLVENT PUMP	2	**HEAD:** 1.5 m TDH **POWER:** 9 kW **FLOW:** 1595 m^3/hr	
	RICH SOLVENT FLASH	1	108 C and 1.93 bara **FLOW:** 1527 m^3/hr solvent recovered	Includes pump skid
	SEMI-LEAN MEA COOLER	1	**DUTY:** 388 GJ/hr **FLOW:** 1527 m^3/hr solvent	
	LEAN SOLVENT COOLER	1	**DUTY:** 30 GJ/hr **FLOW:** 1622 m^3/hr solvent	

ITEM	EQUIPMENT SCOPE	QTY	CAPACITY BASIS/DATA	REMARKS
	MEA MAKE-UP TANK	1		
	MEA STORAGE TANK	1		
MEA COOLING SYSTEM				
	EVAPORATIVE COOLING TOWER	1	**DUTY:** 1041 GJ/hr	
CO2 COMPRESSOR EQUIPMENT AND AUXILIARIES				
	BOOSTER CO_2 COMPRESSOR	1	**DRIVER:** 187 kW **STAGES:** 1 **FLOW:** 34250 kg/hr 13432 m^3/hr **INLET:** 1.4 bara **OUTLET:** 1.85 bara **COOLING:** 0.32 GK/hr	
	MULTI-STAGE CO_2 COMPRESSOR	1	**DRIVER:** 15,970 kW **STAGES:** 8 **FLOW:** 178,583 kg/hr 56,475 m^3/hr **INLET:** 1.78 bara **OUTLET:** 184 bara **COOLING:** 105 GJ/hr	
	TEG GAS DEHYDRATOR	1	**OPERATING PRESSURE:** 60 bara **OUTLET MOISTURE:** 68 kg/MMNM^3	

2.2.2 Case 2 – Lignite Processing Plant Addition

The Case 2 design scenario considers an addition of a CO_2 compression system to a yet to-be-built lignite processing plant. The site is assumed to be located on New Zealand's South Island. The Case 2 evaluation will target a total CO_2 compression of 4,000,000 tonnes per annum and for the purposes of this study, the process as assumed produces urea from lignite. This assumption is purely coincidental to any announcements already made in the media on similar topics by industry representatives.

Site Description

The heat and mass balances have been evaluated at the ISO standard conditions as presented in Table 2-11.

Table 2-11: ISO Conditions

Parameter	Units	Value
Elevation above mean sea level (AMSL)	meter	0
Barometric Pressure	kPa	101.325
Design Ambient DBT	°C	15
Design Ambient Relative Humidity,	%	60
Cooling type		Evaporative Cooling tower

DBT - dry bulb temperature

CO_2 Characteristics

It is assumed that gaseous CO_2 will be delivered to the CO_2 compression system from the lignite to urea plant with characteristics as shown in Table 2-12.

Table 2-12: Urea Plant CO_2 Characteristics.

Parameter	Units	Value
Flow rate	kg/hr	456,621
Pressure	Barg	0.4
Temperature	°C	15
Composition		
Ar	Mol %	0.10
CO_2	Mol %	97.80
H_2O	Mol %	0.10
N_2	Mol %	0.80
O_2	Mol %	1.20

The gaseous CO_2 will be compressed and then delivered to the transport pipeline at the plant boundary as a supercritical fluid. The assumed pipeline CO_2 specification is presented in Table 2-13.

Table 2-13: Urea Plant CO_2 Specification

Parameter	Units	Value
Pressure @ Plant Boundary	barg	190
H_2O, max	ppmv	100

System Description

The process presented on the block flow diagram in Table 2-14 (Heat and Mass Balance Table 2-15) is based on multistage isothermal compression with intercoolers after each stage. Eight compression stages are required to accommodate the pressure ratio of 136 between the feed gas from the lignite processing plant (Stream 81) and the CO_2 pipeline (Stream 90). An isothermal compression process is selected because it requires less compression power, as the gas temperature entering each compressor stage is maintained constant and relatively low by the means of interstage cooling. The heat from the interstage cooling is rejected to a cooling tower. It is estimated that two CO_2 compression trains are needed to satisfy the total flow rate of 4,000,000 tonnes per annum (Table 2-16).

Figure 2-14: Diagram of CO_2 Compression System (Case 2)

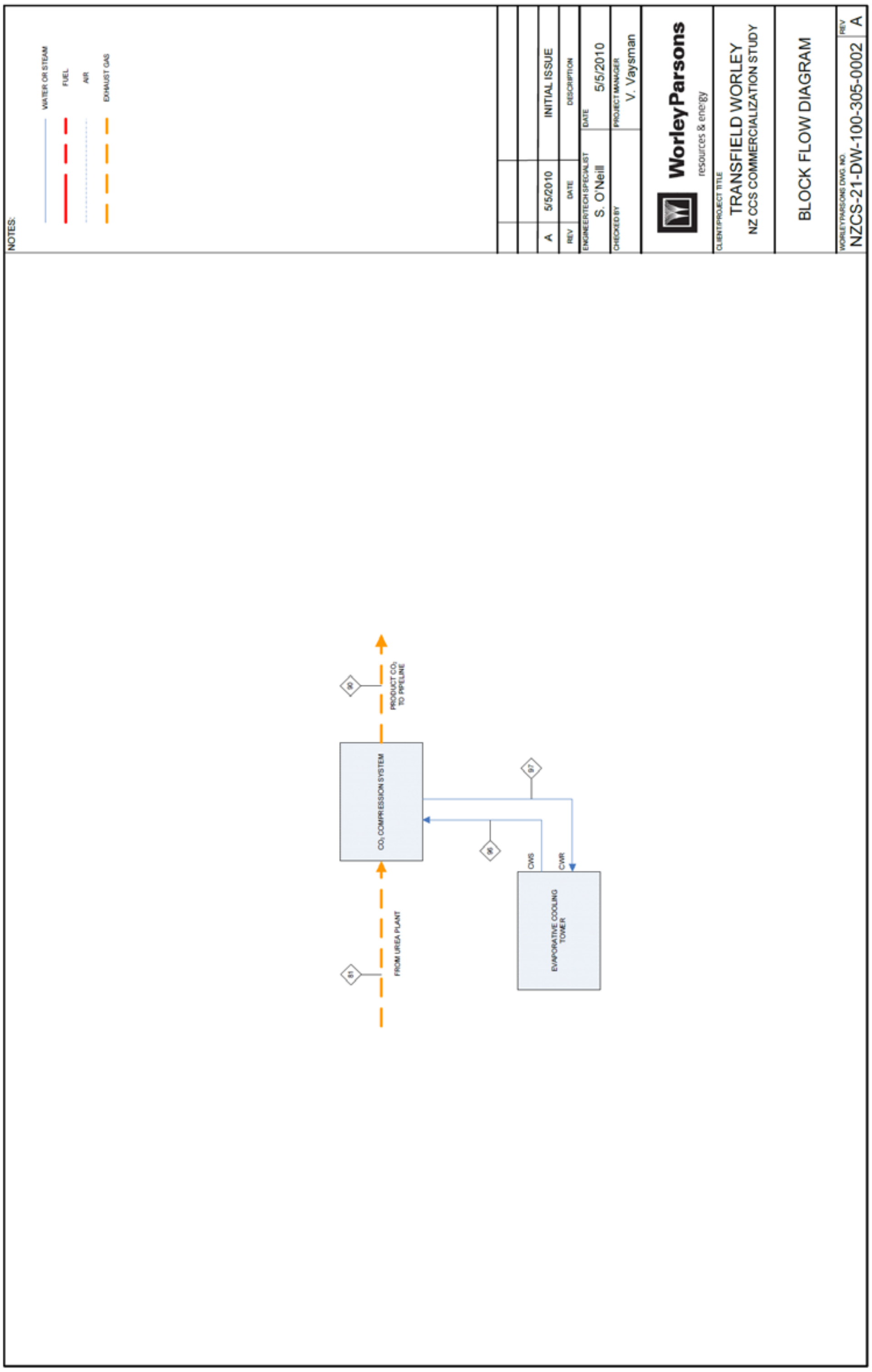


Table 2-15: CO_2 Compression System HMB (Case 2)

Transfield Worley - New Zealand CCS Commercialization Study
Heat and Material Balance (SI UNITS)
CO_2 Compression & Dehydration
NZCS-21-DW-100-305-0002

5/5/2010

PFD Stream No.	81		90		96		97									
DESCRIPTION	Urea CO_2 to Compression		Product CO_2 to Pipeline		CWS to CO_2 Compression Intercooling		CWR from CO_2 Compression Intercooling									
V&L Mixture Components	kgmol/hr	Mol %	kgmol/hr	Mol %	kgmol/hr	Mol %	kgmol/hr	Mol %	kgmol/hr	Mol %	kgmol/hr	Mol %	kgmol/hr	Mol %	kgmol/hr	Mol %
Ar	11	0.10	11	0.10	0	0.00	0	0.00								
CO_2	10,300	97.80	10,300	97.80	0	0.00	0	0.00								
H_2O (and ionic species)	11	0.10	11	0.10	320,018	100.00	320,018	100.00								
N_2	84	0.80	84	0.80	0	0.00	0	0.00								
O_2	126	1.20	126	1.20	0	0.00	0	0.00								
TOTAL	10,531	100.00	10,531	100.00	320,018	100.00	320,018	100.00								
V&L Mixture Components	kg/hr	Mass %	kg/hr	Mass %	kg/hr	Mass %	kg/hr	Mass %	kg/hr	Mass %	kg/hr	Mass %	kg/hr	Mass %	kg/hr	Mass %
Ar	421	0.09	421	0.09	0	0.00	0	0.00								
CO_2	453,291	99.27	453,291	99.27	0	0.00	0	0.00								
H_2O (and ionic species)	295	0.06	295	0.06	5,765,216	100.00	5,765,216	100.00								
N_2	2,360	0.52	2,360	0.52	0	0.00	0	0.00								
O_2	255	0.06	255	0.06	0	0.00	0	0.00								
TOTAL	456,621	100.00	456,621	100.00	5,765,216	100.00	5,765,216	100.00								
V&L Mixture Properties																
Vapor Frac	1.00		---		0.00		0.00									
Temperature, C	15		26		17		28									
Pressure, bar	1.4		191.0		6.2		4.8									
Enthalpy, kJ/kg	-8,888		-9,136		-15,898		-15,851									
Density, kg/m3	2.55		---		999.10		996.43									
Molecular Weight	43.36		43.36		18.02		18.02									

Note: In this table the enthalpy reference point is natural state of the constituent elements in their standard states at 1 atm and 25°C.

Table 2-16: Major Equipment List (Case 2)

ITEM	EQUIPMENT SCOPE	QTY	CAPACITY BASIS/DATA	REMARKS
CO_2 COMPRESSOR EQUIPMENT AND AUXILIARIES				
	MULTI-STAGE CO_2 COMPRESSOR	2	**Driver:** 22,526 kW **Stages:** 8 **Flow:** 228,311 kg/hr 89,553 m^3/hr **Inlet:** 1.4 bara **Outlet:** 191 bara **Cooling:** 268 GJ/hr	
COOLING SYSTEM				
	EVAPORATIVE COOLING TOWER	1	**DUTY:** 268 GJ/hr	

Attachment 3
Carbon Storage

Cautionary Statement

Advice and opinions given by Schlumberger Carbon or Oilfield Services and management may contain forward-looking statements. Forward looking statements do not guarantee performance and are not recommendations for action. Such statements are generally identifiable by the terminology used, such as "plan", "forecast", "expect", "expectation", "assumption", "estimate", "budget", "probability" or other similar wording. Forward-looking statements include but are not limited to references to drilling results, success rates and plans, the form of field developments, seismic activity, costs & margins, CO_2 injection rates and volumes, oil and gas production levels and the sources of growth thereof, results of exploration activities, and dates by which certain areas may be developed or may come on-stream as well as other market and economic assumptions. These forward-looking statements are subject to known and unknown risks and uncertainties and other factors which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Many factors are beyond the control of Schlumberger companies. The forward-looking statements contained in this report or any advice is expressly qualified by this cautionary statement.

Confidentiality

This work has been performed as part of a TW lead consortium under sub-contract to the NZCCS Partnership via FRST New Zealand.

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Approvals

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Verified by	Geoff Ingram
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3. NEW ZEALAND CCS CASE STUDIES – OPTIONS FOR CO_2 STORAGE

3.1 Introduction

Storage of CO_2 is the critical path technology in the CCS value chain. From a project developers perspective if integrated CCS systems are being pursued the cost of storage represents a key uncertainty associated with the "finding" costs to locate and develop a suitable storage site. This is a fundamental issue for decision-makers in considering deployment of commercial scale, integrated CCS projects.

In order to 'de-risk' the storage stage of a CCS project, multiple sites will need to be appraised to locate a suitable CO_2 storage site for a project. A portfolio of geologic storage options on a project or region-wide basis will need to be found and appraised to spread the risk associated with the "finding" cost. For example, the Australian Government has the National Storage Taskforce under the National Low Emissions Coal Council and in the United States, the US Department of Energy is also funding several regional partnerships with the objective of demonstrating several different types of capture operations at a variety of locations that cover major potential geologic storage formations in the United States and Canada. In New Zealand, NZCCS Partnership has undertaken some geological mapping work through the CO2CRC and GNS which is the first stage of data collation for CO_2 storage site selection and characterisation.

Uncertainty Around Storage Drives Entire CCS Project Economics

In a rational economic scenario, there is a cost of acquiring property rights for the exploration and development of geological formations for CO_2 storage that has to be met and the long-term price of CO_2 would be sufficient for private investment into CCS. There is the possibility of a proponent developing a storage site with an economic return that is greater than the payback required for the 'finding' costs. In this circumstance there is an incentive for the private sector to risk these 'finding costs' for profit to be derived later through CO_2 storage.

Due to the current uncertainty around the pricing of CO_2 and/or the lack of certainty around property rights for CO_2 storage, there is little or no incentive for any private companies to risk capital in locating and developing CO_2 storage sites. In the absence of targeted exploration, existing knowledge around potential storage sites tends to be very high level assessments which are derived from broad generalisations of geology in a particular region or are derived from out of date or obsolete publicly available data previously collected for a different purpose.

Many of the early demonstration CCS projects have also sought to use formations near oil and gas fields to store limited quantities of CO_2. In the case of commercial projects such as Sleipner and In-Salah, the field is owned by the same company extracting the oil and gas and the CO_2 is re-injected into either the same formation or one nearby. In these cases the "finding" costs for such projects have already been incurred through the exploration and appraisal of such assets for hydrocarbons. This is not the case with the CCS projects for power generation or other industrial processes which may need to have access to, or undertake themselves, fundamental geological exploration to ascertain potential sites for CO_2 storage that are able to receive large volumes of CO_2 for storage over several decades of plant operation.

Figure 3.1 illustrates an appraisal process that would need to be undertaken to identify transport and storage sites at a particular location. This could benefit from public funding or Public Private Partnership (PPP) funding to help accelerate the deployment of commercial scale integrated CCS projects through sponsoring the upfront "finding" costs for CO_2 storage sites. While the schedule does not necessarily affect the cost of CCS, it indicates that for commercial scale, integrated facilities to be in operation by 2020 the identification and characterisation of sites must be initiated now, if not already underway.

As shown in Figure 3.1, the first stage of site selection covers a desktop study on a range of prospective sites using publicly available geological data to ascertain storage fundamentals such as a suitable seal, first pass porosity and permeability data that allows a portfolio of perhaps 6-8 “plays” to be earmarked as potential sites warranting further investigation. This could take up to 12 months with a full technical team of geologists and reservoir modellers at a cost of approximately $1-2 million, depending on the quality of the data initially available.

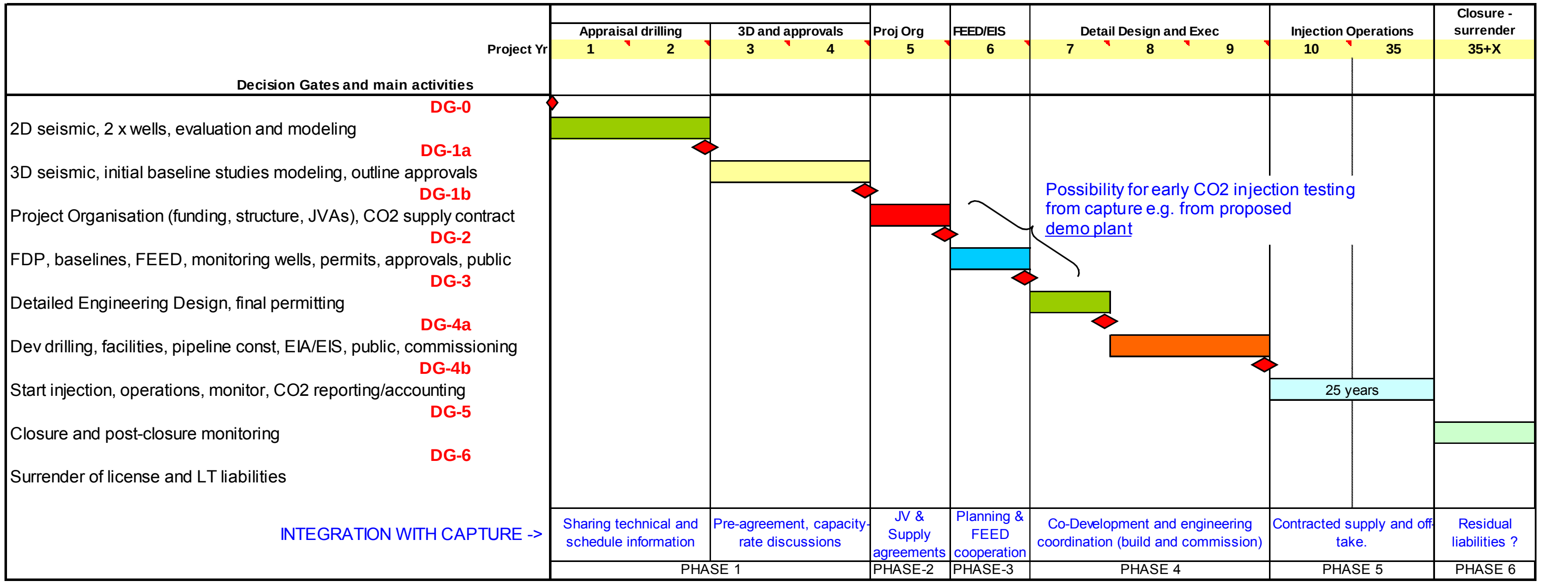
From this point, assuming property rights and funding can be accessed, there would likely be new seismic studies done to determine where to drill the wells to test and confirm prospective sites for injection potential and to determine site capacities (bearing in mind that it will be injection rates that will determine the commerciality of a site operation going forward).

Fundamentally, the geology will drive the storage site selection and the site will drive the commerciality of commercial scale, integrated CCS projects. The “finding” cost can vary from $25 million in the ideal case to $150 million or more depending on the geology. It is evident that as many as 4-5 years of expenditure may be incurred prior to technical and regulatory uncertainty having been reduced around a potential storage site that would allow FID and full field development plans to be executed.

NZCCS could play a role in future emissions reductions in New Zealand if the identification of, and characterisation of suitable storage sites is completed; this is a critical factor in the deployment of CCS in New Zealand. There is a role for Government to encourage some more fundamental exploration of the local geology, particularly in the South Island, to fully delineate the existing uncertainties around the potential of long term secure storage of CO_2. Seismic and exploration wells would be of immense benefit in the South Island. The North Island is relatively better characterised by exploration/production of existing hydrocarbon producing assets.

Figure 3.1 Conceptual site(s) exploration & appraisal study schedule.

GENERIC TRANSPORT & STORAGE - SCHEDULE FOR DELIVERY



DG-0 : Ready to proceed to Phase 1 ? All Conditions Precedent met (tenements & funding) ?

DG-1a: Ready to progress to 3D & feas ? The evaluation of drilling data supports containment, injectivity and capacity forecasts ?

DG-1b: Ready to progress to Project Organisation, Phase 2. Evaluation of 3D seismic, initial EIA, pipeline feasibility reports support full development project - outline consents in place.

DG-2 : Ready to progress to FEED, FDP & full EIA. Commercial agreements in place (funding, financing, JV and CO2 supply etc).

DG-3 : Ready to progress to Detailed Engineering Design. FDP, pipeline FEED, environmental baselines, public confidence and permits all in place.

DG-4a: Ready for FID ? Detailed Engineering Design complete ready to start execution.

DG-4b: Ready to start Injection Operations ? Commissioning complete, operation plans in place, all permits ready, M&V scheme in place.

DG-5 : Ready to cease injection ? Site license fulfilled, licensed storage capacity met. Approved plan for post-closure monitoring.

DG-6 : Ready to surrender license ? Monitoring and modeling confirms little residual CO2 movement or risk.

Source: GCCSI, 2009

3.2 New Zealand NZCCS Partnership Case Studies – Storage

Two case study scenarios were agreed with NZCCS Partnership. This paper outlines the conceptual storage part of the case studies using two specific example locations and data agreed with the NZCCS Partnership. For reference, background information on storage site selection methodologies and the development timelines are shown in Figure 3.1.

In both cases, publicly available data was used to identify and select **a conceptual storage location** that was to serve as the storage reservoir for the case studies. It was also assumed that the exploration and appraisal program that would start in late 2010 to prove up these sites (and others as a potential portfolio of storage options) was successful and that the locations had been shown to have suitable seals and other geological factors that would allow for safe storage of CO_2 over the longer term. **These locations are in no way being recommended as suitable storage sites** and should only be used as a hypothetical case for storage potential in both the North and South Islands. The developmental timeline for the storage site starts at DG2 (Figure 3.1) to allow injection to commence from 2016 onwards. In both studies the 'finding costs' in the site selection and characterization and discounted costs back to 2010 $ using a discount rate of 10%. These may or may not be sufficient to cover real project costs.

Vertical injection wells are used in both cases as the standard. Stimulation by fracturing or deviated well placement that could increase injection rates was not considered. Such well design considerations would be considered after the site characterisation has been completed and the full field development program is being done.

The basis used is the injection well pressure is below the fracture pressure (90% of fracture pressure) which provides the first order constraint on potential storage volumes. CO_2 injection above the fracture pressure could increase well injectivity rates but at the risk of fracturing the cap-rock. An accurate determination of the actual fracture pressure can only be derived from laboratory tests on new core samples from both areas. Another assumption is that sufficient pore space is available over the life of the injection operations.

The Case Study Scenarios are as follows:

3.3 Case Study 1: Existing Carbon Sources (retrofitted)

- North Island location
- Carbon Sources = medium-sized NGCC power station (~ 1000kT/y) + Small gas processing facility with existing CO_2 separation process (loosely based on Ballance Urea process or Vector Gas processing, say 300kT/y)
- Carbon Transport = underground pipelines a) 30km gas plant to power plant, then b) 30km combined gas and power plant emissions to injection wellsite. Note: include provision for future expansion e.g. addition of other CO_2 sources.
- Carbon Sink = Onshore (assume capacity = 15PJeq Natural Gas). Loosely based on Taranaki type location e.g. Stratford Power Station coupled with Ballance Fertiliser/Vector Gas processing and assuming spare onshore reservoir in TAWN, Kahili region.
  (ref http://www.crownminerals.govt.nz/cms/petroleum/blocks-offers/kahili-block-offer)
- Typically the geography in the North Island is very hilly, steep (up to 300m above sea level).

Thus for storage, the pertinent points are 1.3MT/year injection and storage with operations commencing in 2016 for an expected 30 year operation.

The newly released Kahili blocks (http://www.crownminerals.govt.nz/cms/pdf-library/petroleum-blocks-offers-1/kahili-block-offer/searchterm=Kahili) are taken as the 'conceptually proven' storage reservoir. One key reason for this is to avoid any potential fallout that could arise from naming a currently leased block which has an operator in production. It is not the intent of this study to suggest that the sovereign rights of existing asset owners be compromised. (Figure 3.2 shows the location of the site and Figure 3.3 the known seismic lines around the area).

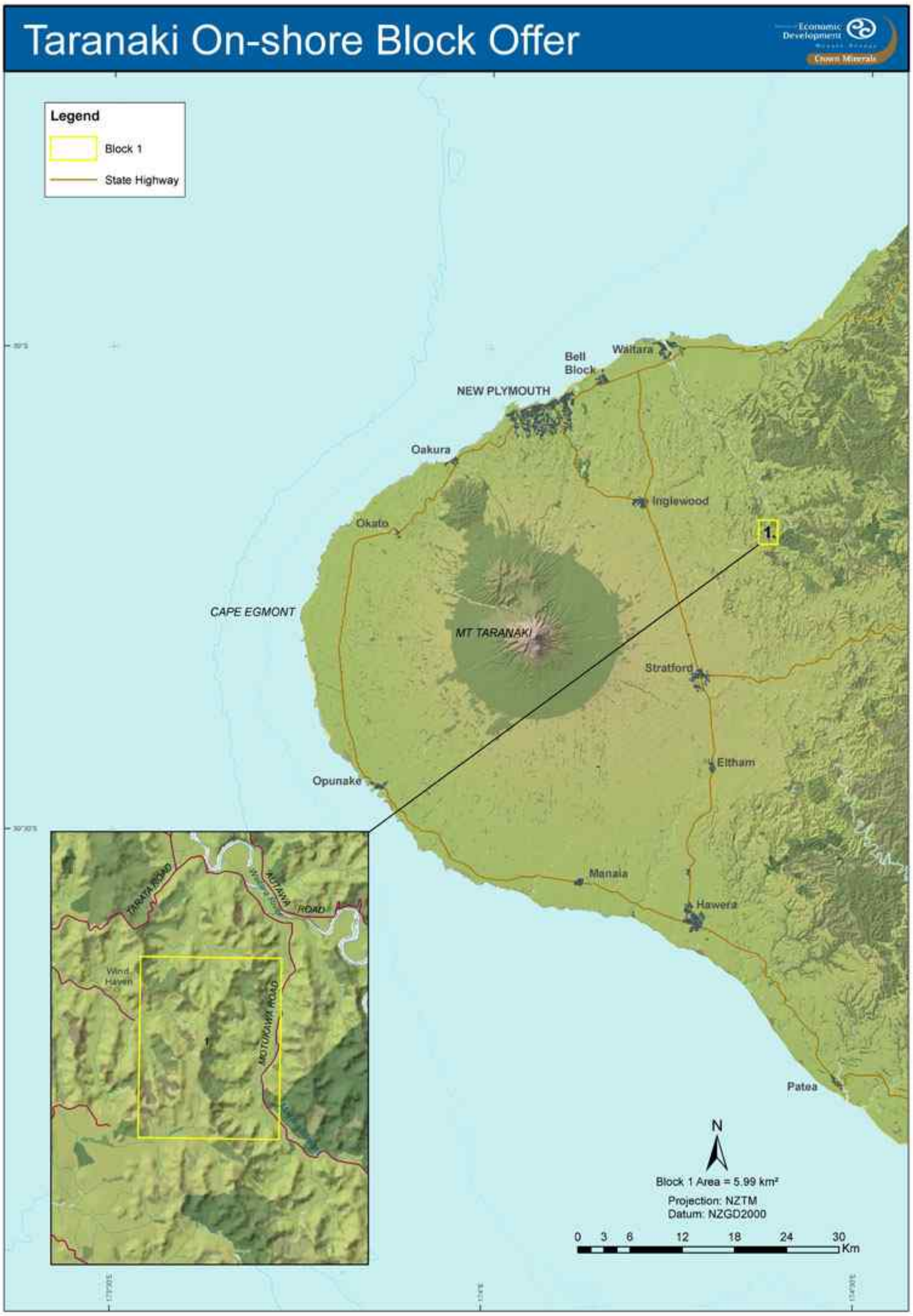


Figure 3.2 Location of Kahili Site, Taranaki

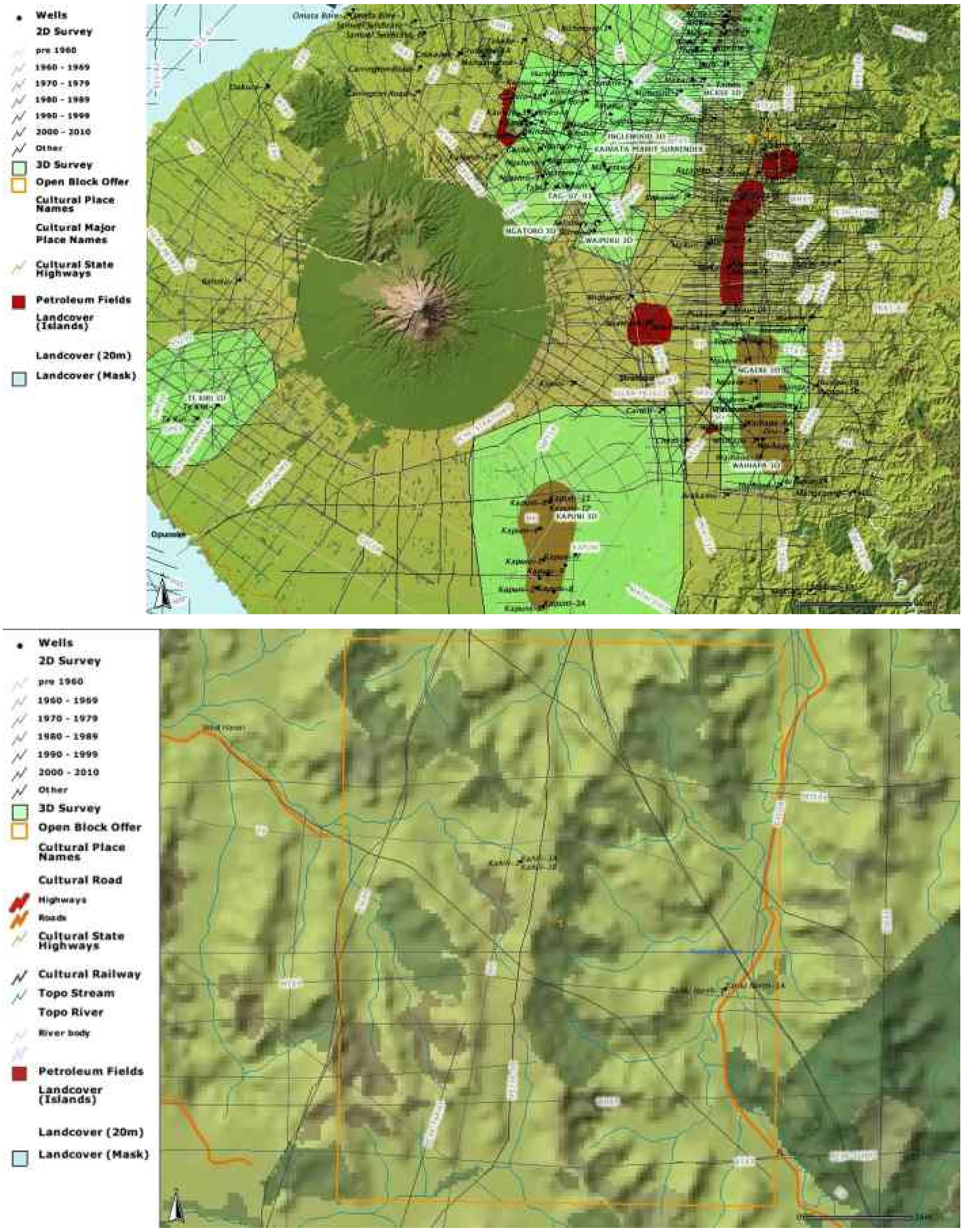


Figure 3.3: Distribution of seismic surveys at Onshore Taranaki (upper map). Orange rectangle marks the Kahili Block (NE area of the map). Close-up of the Onshore Taranaki Kahili Block (orange rectangle, lower map). Source: Crown Minerals, Online Services.

Note that the block offer is small and probably unsuitable for CCS (~6km^2), thus plume migration would necessitate a much wider acreage/tenement being gazetted for CCS storage (contrast with the onshore areas released by the State Government of Victoria Australia (http://new.dpi.vic.gov.au/earth-resources/earth-resources-industries/geological-carbon-storage/2009-victorian-onshore-acreage)).

The fundamental assumption when considering this site was that it had a proven seal. Potential reservoir characteristics that would allow an estimate of the injectivity prior to the economic model were also reviewed. The injectivity estimates drive the well count and hence the ultimate project economics.

Play (potential reservoir and seal):

Proven Tariki Sandstone reservoir (Early Oligocene) deposited in a submarine fan environment (compare PR 2585, 2000 and Higgs et al. 2004). Amalgamed sandstones up to 200m thick, sealed by Late Oligocene Otaraoa Formation and Early Miocene Manganui Mudstone (Taimana Formation) (see Fig. 3.3). There are a number of oil and gas discoveries within the formations including the Kapuni and Maui fields. It was not assumed any depletion etc. of existing fields but rather that the new Kahili field is only available for CO_2 sequestration and that there is no contamination of existing hydrocarbon to concurrent operations either within the Kahili field or elsewhere.

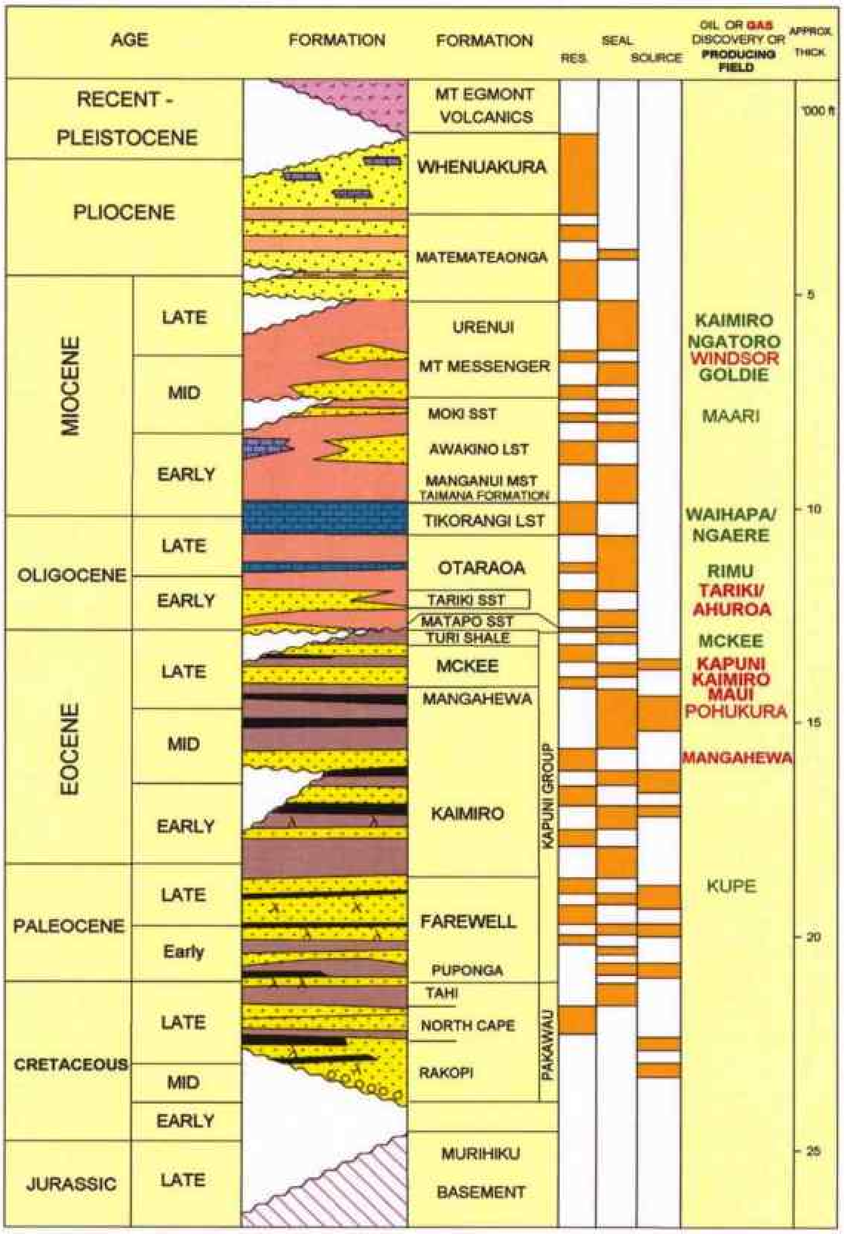


Figure 3.4: Generalized Stratigraphy of the Taranaki Basin (WCR Kahili-1, PR2676, 2002).

Reservoir properties (Reservoir summation Kahili-1 WCR):

There is a sandstone horizon which is 65m thick (gross). 30.3m of the horizon has reservoir quality (net). To define the reservoir different parameters cut offs are used to define net:

- if PHIE(porosity)>0.1(10%) the sandstone is a reservoir
- if SW(water saturation)<0.6(60%) => reservoir
- if Vclay(clay content)<0.3(30%) =>reservoir
- if all these parameters (cut offs) are correct, there is a reservoir rock (net).

Porosity: 15% average, peaks at about 18%

Permeability (K) estimated from offset wells core measurements: 50-100 mD (from WCR Kahili-1A/1B, compare Fig. 3.5)

33000ppm NaCl equiv. formation fluid salinity as a result from log interpretation; 35000ppm NaCl equiv. formation fluid salinity in offset wells (Tariki-1, DST sampling)

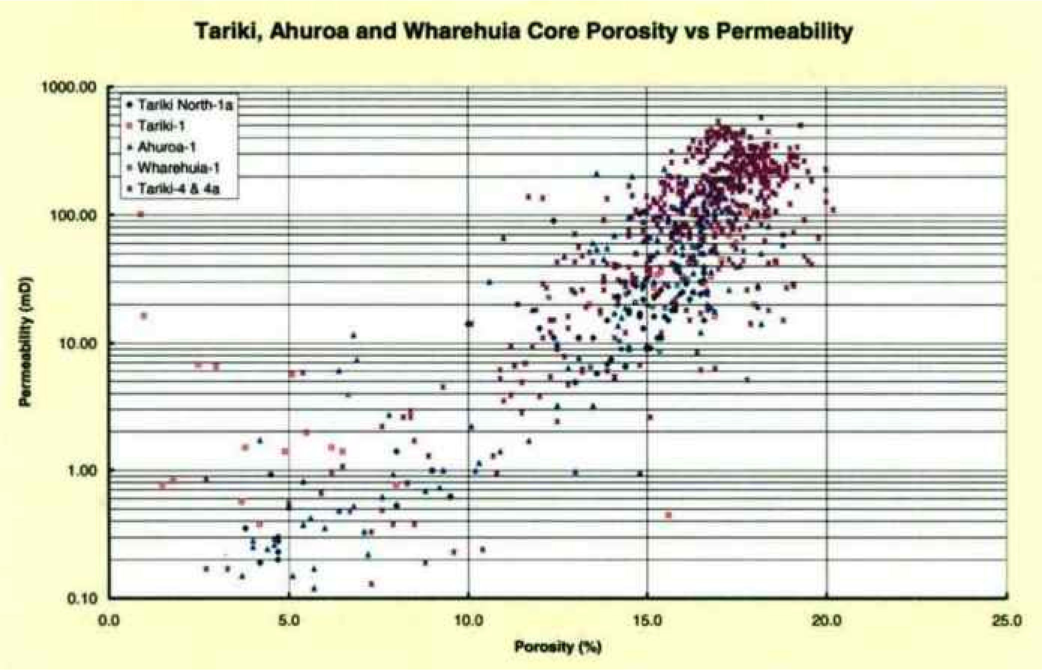


Figure 3.5: Offset Core data porosity vs. permeability plot (WCR Kahili-1A, 1B, PR2900, 2003).

This gives typical reservoir characteristics for the injectivity models and the reservoir assumptions (later listed in Table 1).

Conclusions:

The 2D seismic line interpretation used for the well design of Kahili-1 shows the uncertainties of this technique in structural complex areas (Figs. 3.6 and 3.7). The target horizon was found 285m deeper than prognosed and the well did not drill the crestal position of the anticlinal structure. This target was finally successfully reached by drilling the second side track, shown in Fig. 3.8 (Kahili-1B).

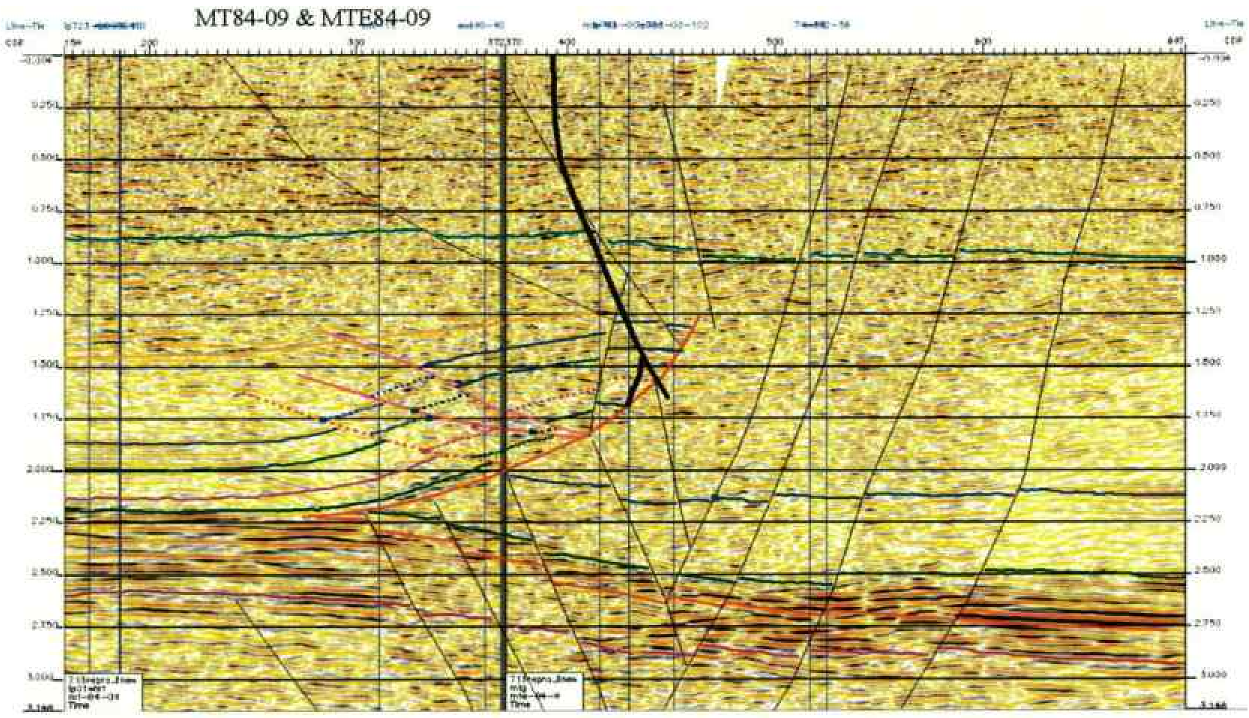


Figure 3.6: Composite seismic line across the Kahili Structure near the Kahili-1A TD location (WCR Kahili-1A, 1B, PR2900, 2003).

The existing wells were drilled to explore structural high positions and do <u>not</u> test the reservoir rocks at the flanks of the structure.

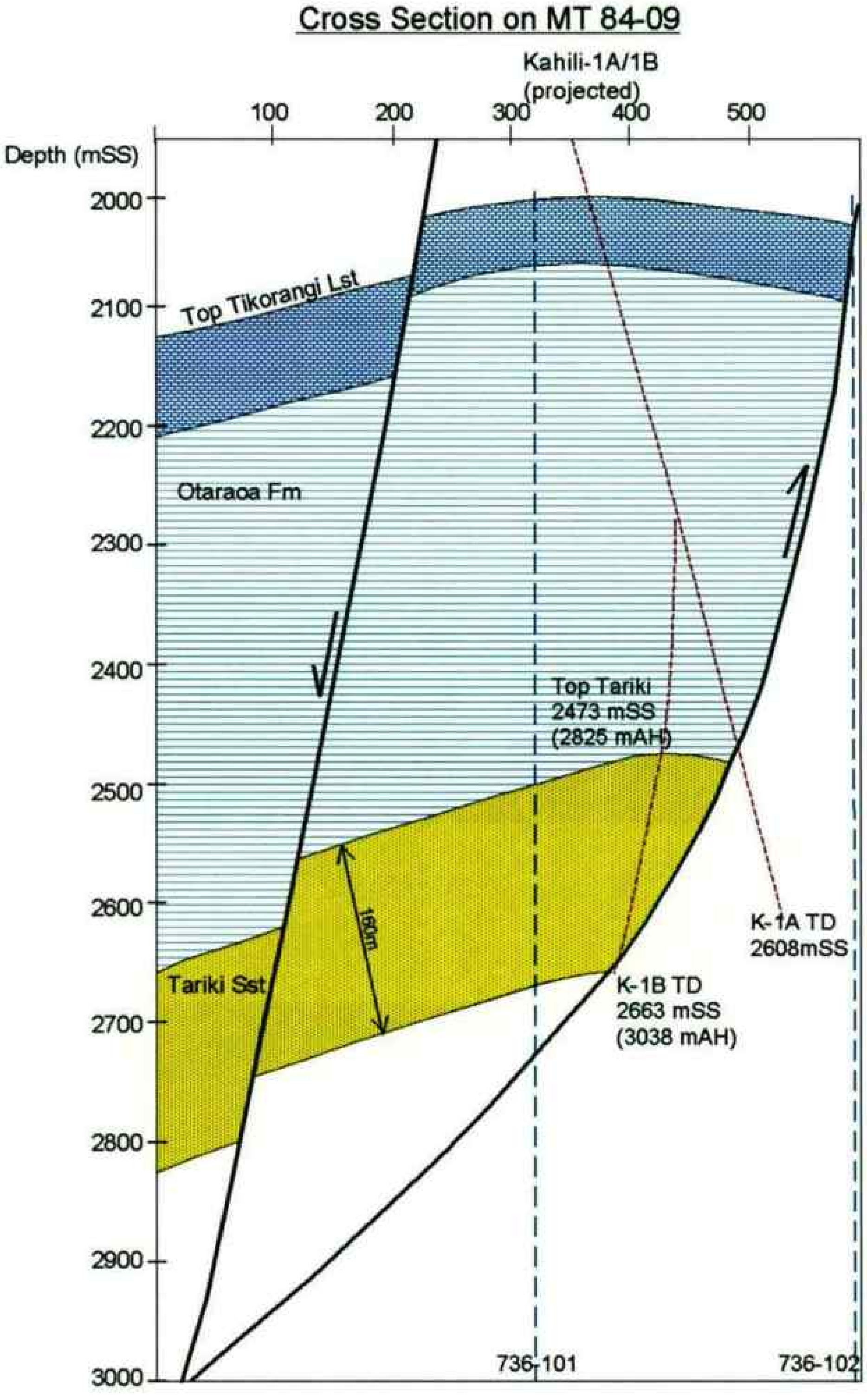


Figure 3.7: Cross section on seismic line MT-84-09 showing TD locations of Hahili-1A and 1B (WCR Kahili-1A, 1B, PR2900, 2003).

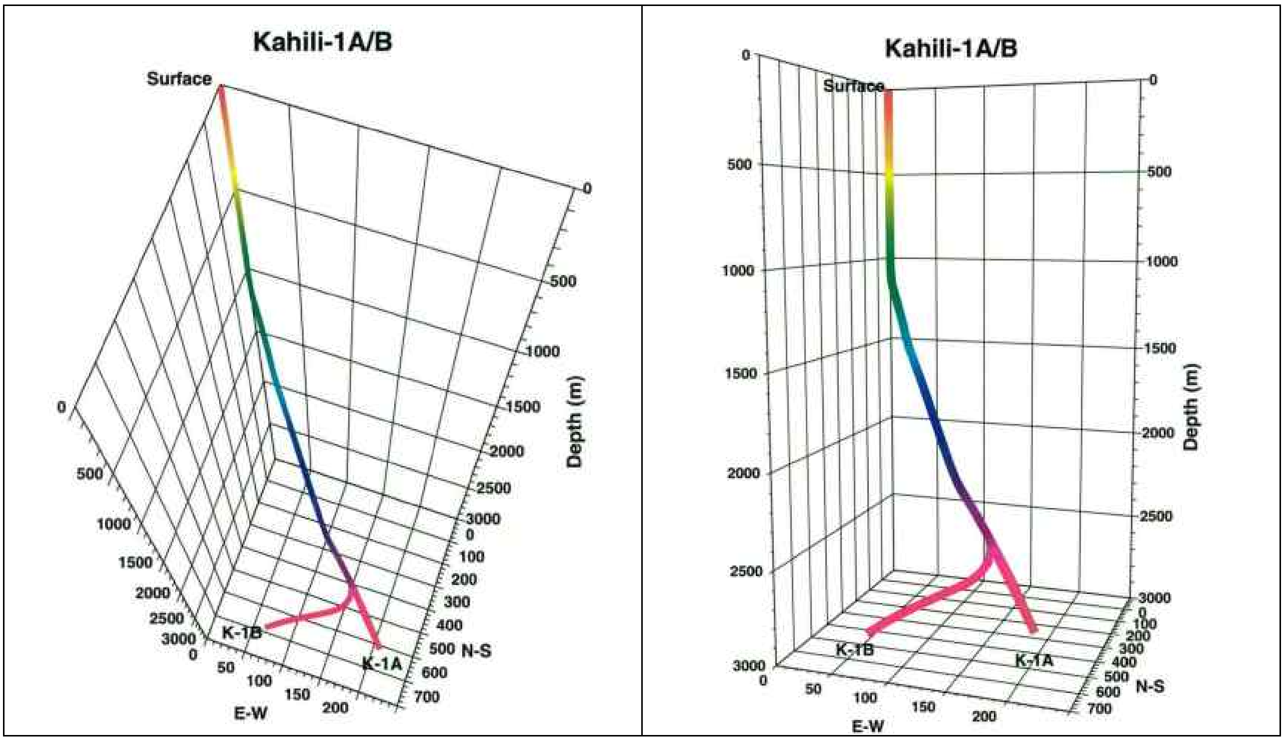


Figure 3.8: Kahili-1A/B well plan perspective (WCR Kahili-1A, 1B, PR2900, 2003).

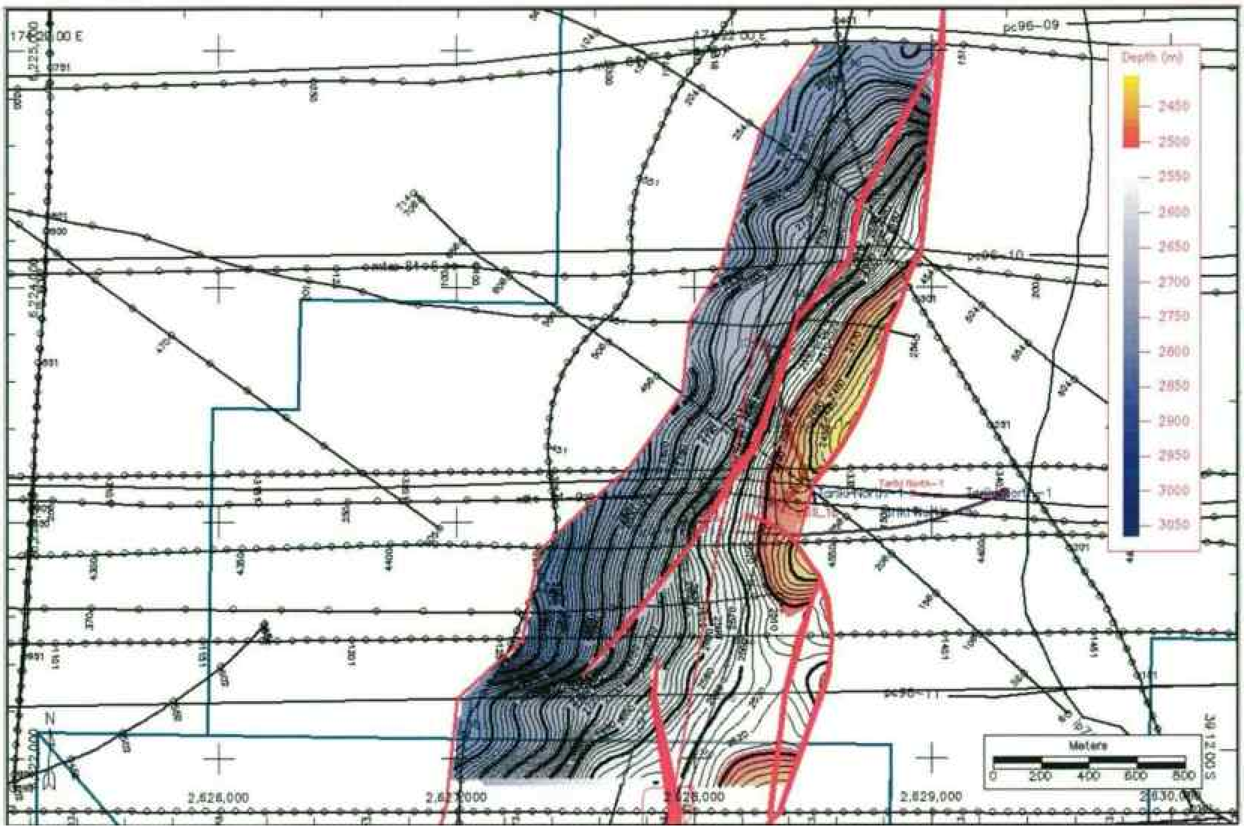


Figure 3.9: Depth map on Top Tariki Sandstone (WCR Kahili-1A, 1B, PR2900, 2003).

To test this play, 3D seismic would be required because of the structural complex setting. The play comprises the deep saline aquifers of the Early Oligocene Tariki Sandstone of the Otaraoa Formation which were drilled by the well Kahili-1 unintentional. This succession has been interpreted as clastic deposits in a submarine fan environment. Regional seal exists with thick marine calcareous mud- and siltstones of the Late Oligocene Otaraoa Formation and the Early Miocene Manganui Formation, dominated by deepwater mudstones.

Thus, a high level exploration and appraisal program (to DG1/DG2) of the generic site development plan (Figure 1) would remove the technical uncertainty around the suitability of the site for CO_2 storage.

3.3.1 High level stage-gated CCS project exploration scheme – NORTH ISLAND:

- Screening study. Data mining, review of publicly available data and check of accessibility and ownership
- Scoping modeling study based on available data (containment / capacity / injectivity)
- 3D seismic survey to map the structural complex area (Fig. 3.6 & 3.9)
- 2 exploration wells (stratigraphic test) to prove hydraulic properties of the target horizons
- Drilling of an appropriate number of appraisal wells (due to results of hydraulic testing of the exploration wells) with proper completion and diameter as injection wells

Only after such a program has been completed, would any CCS developer be in a position to be able to decide if the site is suitable or not or would require additional studies for large scale CO_2 storage.

From the cursory geological review, it was assumed that the following reservoir characteristics apply for the North Island case study.

Table 3.10: Assumed reservoir characteristics for the North Island Case Study

1	Mid-formation Depth	m	2750
2	Initial Pore Gradient	psi/ft	0.443
3	Temperature Gradient	C/100m	3.5
4	Permeability	md	50
5	Net Thickness	m	30
6	Porosity	v/v	0.15
7	Fracture Gradient	psi/ft	0.75
8	Injection Pressure Limit (of FG)	%	90%
9	Relative Permeability	-	0.15
10	Drainage Radius	m	2500
11	Wellbore Radius	m	0.11
12	Total Skin	-	5
13	Boundary Type	-	Partially Closed
14	Pore Pressure Escalation (30y) - relative to $P_{pore,initial}$	%	50%
15	Tecton. Stress Grad.	psi/ft	0.18

It was also assumed that there will be seismic acquisition and reprocessing required as part of the site selection process. This is estimated at US$12M (NZ$18M).

Table 3.11: Seismic Required for exploration of Kahili block for CO_2 storage potential

Kahili

No	Cost Component	Indicative Cost Estimate (mil USD)
1	2D reprocessing	0.01
2	Mobilization/demobilization	0.75
3	3D Acquisition	11.25
4	3D Processing	0.11
	Total	12.13

Likewise there will be seismic required during the life of operations of the storage site for monitoring and verification purposes. The assumption is that injection starts in Year 0 (Y0) and that seismic will be a monitoring tool for performance and risk predictions of CO_2 monitoring.

Table 3.12: Seismic shot for exploration and monitoring and verification purposes

Seismic Cost Estimate (mil USD)

Year	**Y-2**	**Y-1**	**Y0**	**Y10**	Y20	Y30	Y35
Kahili	0.01	0	12.11	1.05	1.05	1.05	1.05

The following assumptions on the reservoir performance was also made to derive injection characteristics during the period of operation of the site.

Table 3.13: Reservoir Performance for North Island Case Study

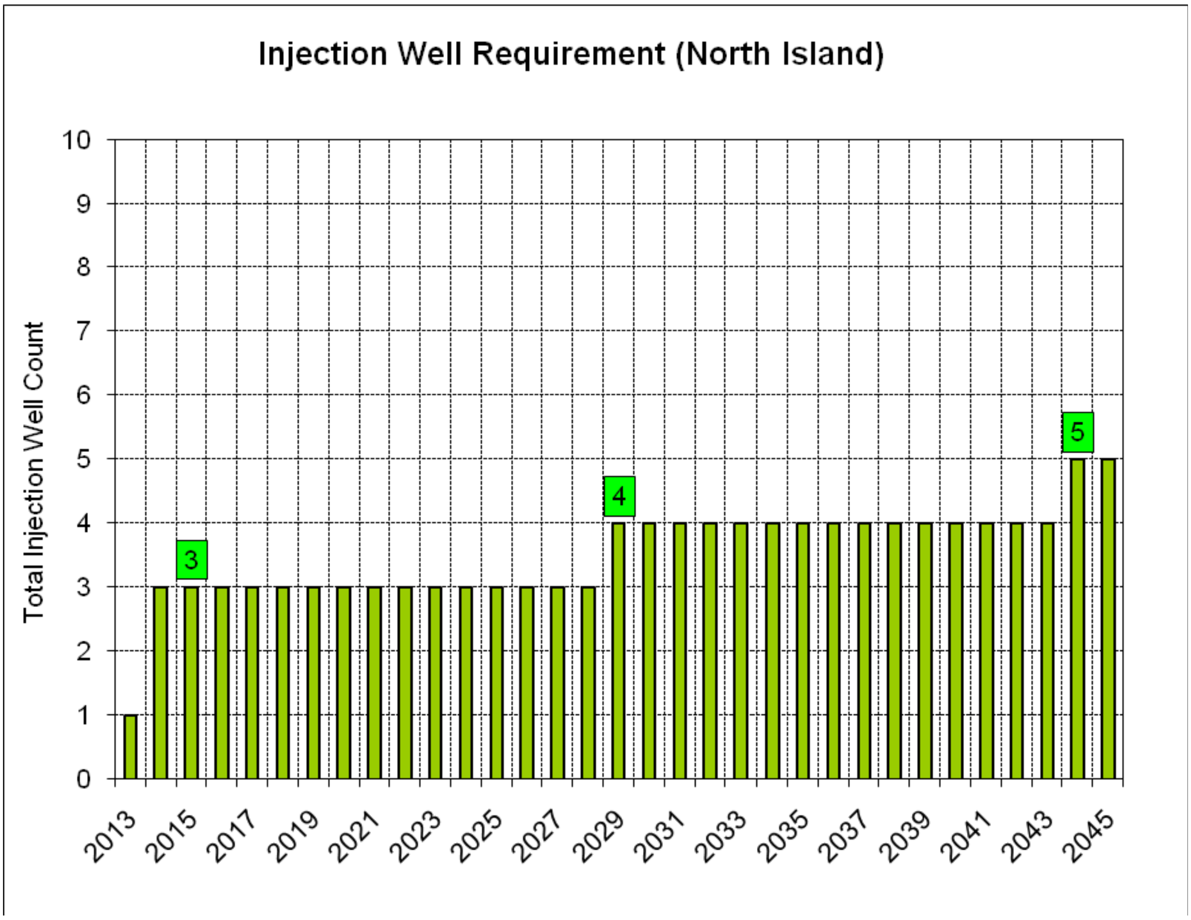
	UOM	North Island
Annual Mass Rate	mil tonne/y	1.3
Injection Period	y	30
Injection Commencement	-	2016
Total CO_2 Mass Stored	mil tonne	39
"Pancake" Areal Coverage (E~ 10%, Swir ~ 50%)	km2	242
CO_2 Density at reservoir conditions	kg/cm	715
Radius (Pancake model)	km	9

Table 3.14: Injection Rates and Well Requirements for the North Island Case Study

	Pseudo-Steady State CO_2 Injection Rate	UOM	North Island
1	Initial Injection Rate (Year 0)	tonne/d/well	1442
2	Final Injection Rate (Year 30)	tonne/d/well	865
3	Initial Injection Well Requirement (Year 0)	-	3
4	Final Injection Well Requirement (Year 30)	-	5

In the case of the North Island, to inject 1.3MT of CO_2 on an annual basis, there would be 3 start wells and finish with 5 wells to enable the continual injection rates to be maintained. The sequencing of wells is as shown below in Figure 3.15.

Figure 3.15: Injection Well Requirement and Sequencing North Island



It was also assumed that the CO_2 is delivered to the wellhead at 116 degrees Celsius and at a pressure of between 243-293 bar which will require compression facilities at the wellhead.

For the Taranaki-based case study, the summary of expenditures is as follows (discount rate assumed to be 10% with no oilfield price inflation allowed);

Table 3.16: CAPEX/OPEX for the North Island Case Study Storage

Summary of Expenditures		UOM	North Island
1	CAPEX (Nominal)	mln A$	$ 112
2	OPEX (Nominal)	mln A$	$ 113
3	Total Expenditure (Nominal)	mln A$	$ 224
4	CAPEX (Discounted)	mln A$	$ 54
5	OPEX (Discounted)	mln A$	$ 20
6	Total Expenditure (Discounted)	mln A$	$ 74

3.3.2 Summary – North Island Case Study Storage

From this conceptual case study, a developer would be looking at approximately A$224M (NZ$280) of total expenditure in CAPEX and OPEX to store some 39M tonnes of CO_2 over the 30 year period using 5 vertical injector wells. The reservoir assumptions are only used to build a rough economic model for storage and are not indicative of real reservoir performance, thus the 'headline' cost of CO_2 stored on a ~$10/t basis must be treated with caution.

The exploration costs and monitoring costs have been built into the storage costs and assume that a 'successful' exploration campaign yields significant savings through exploration wells doubling as injection and monitoring wells, thus realistically the $10/T CO_2 storage costs have a wide margin of error (perhaps as much as 100%).

3.4 Case Study 2: Future Carbon Sources (new plant)

- South Island location. The generic “future plant” location is at Morton Mains
- Carbon Source = New Coal Added Value Plant (CO_2 emissions 4000MT/y) Carbon Transport = 100km pipeline (underground) to injection wellsite.
- Carbon Sink = Onshore (assume adequate capacity to meet emissions over plant lifetime e.g. 30 years)
- Note: - No future capacity provision e.g. smelter/other industry flue gases excluded.
- The South Island geography is low undulating river plains (70m, max above sea level).

South Island, Onshore Winton Basin (Figure 3.17)

T = 4 MT/y: 30 years operating

1st estimate: ~ 10 wells / ~1500-2000m Total Depth (TD) (based on the assumption of an injectivity of 300 kT/y into every successfully placed well).

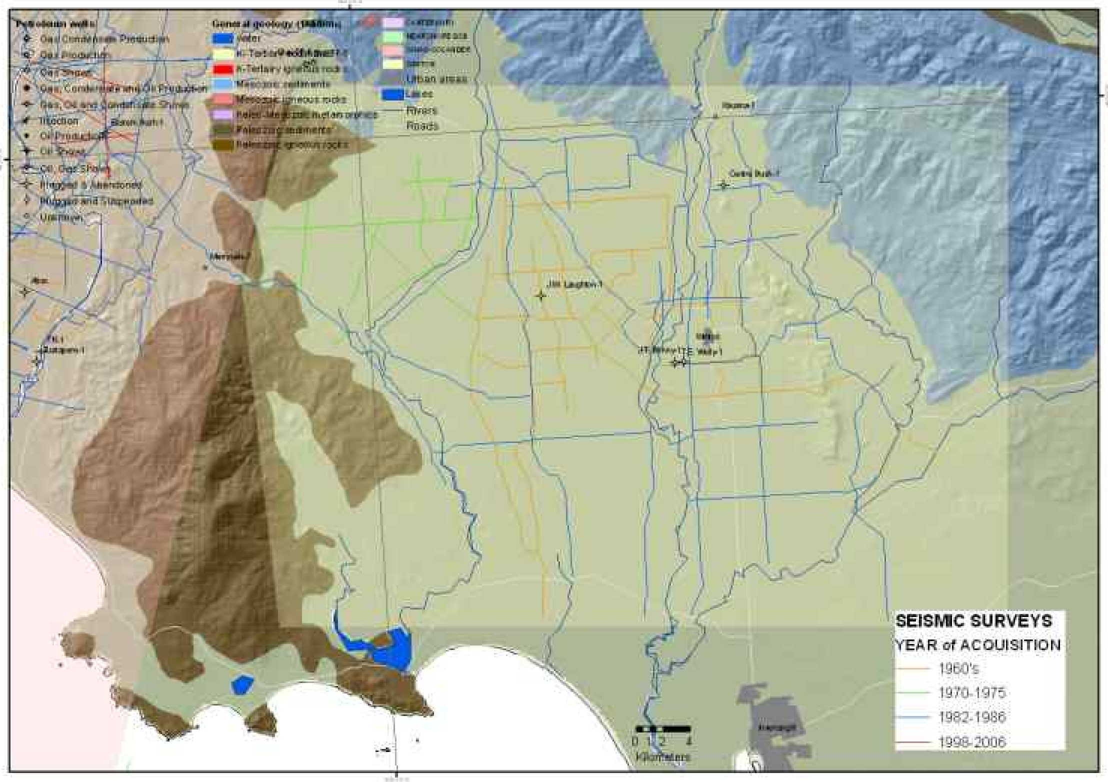


Figure .3.17: Distribution of 2D seismic lines in the Winton Basin (GIS project GNS, Craig Jones, 2009).

Play (potential reservoir and seal):

Undrilled half graben-fill fluvial sandstones within the Late Eocene Mako Formation (Nightcaps Group), sealed by the Oligocene Winton Hill Formation (regional seal, thick marine mudstone), compare Figure 3.17.

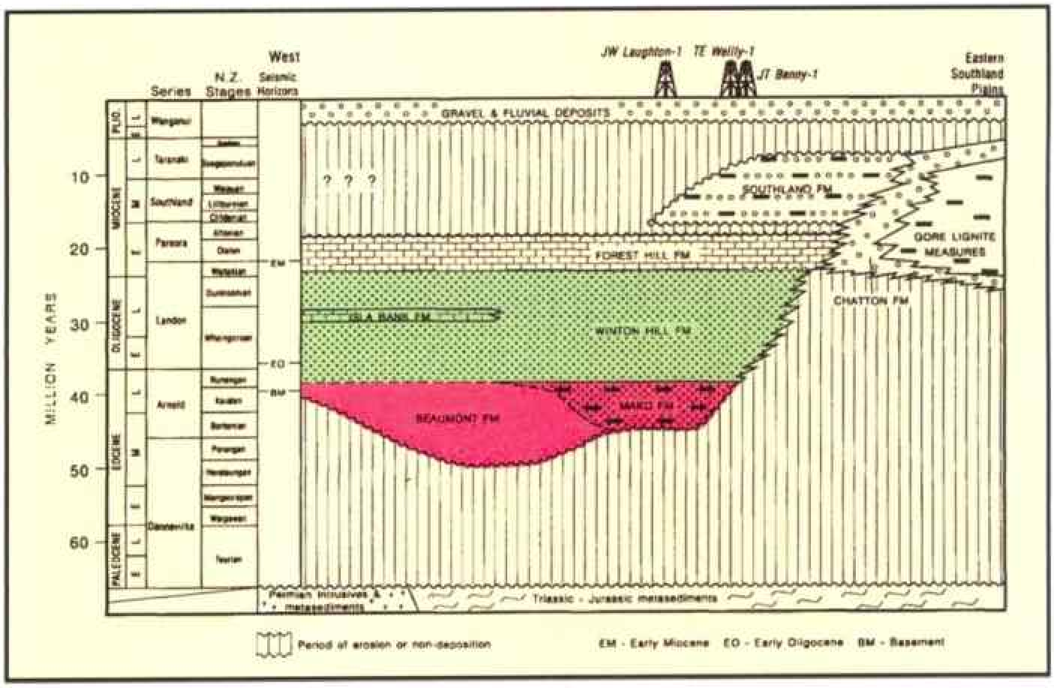


Figure 3.18: Stratigraphic diagram for the Winton Basin (Cahill, 1995).

No reservoir summaries, hydraulic test results or core measurements are available for the Mako Formation in Winton Basin. The Late Eocene Mako Formation play remains entirely speculative with no proven (encountered) reservoir. Whilst a geologically reasonable hypothesis, the play remains relatively high risk. One well would be required just to prove the presence of sands in the mapped graben areas (figures 3.18 and 3.20) and to test the play. At least 2 additional exploration wells would be necessary to prove the conceptual model of the half graben-fill fluvial sandstone and its geometry and facies distribution.

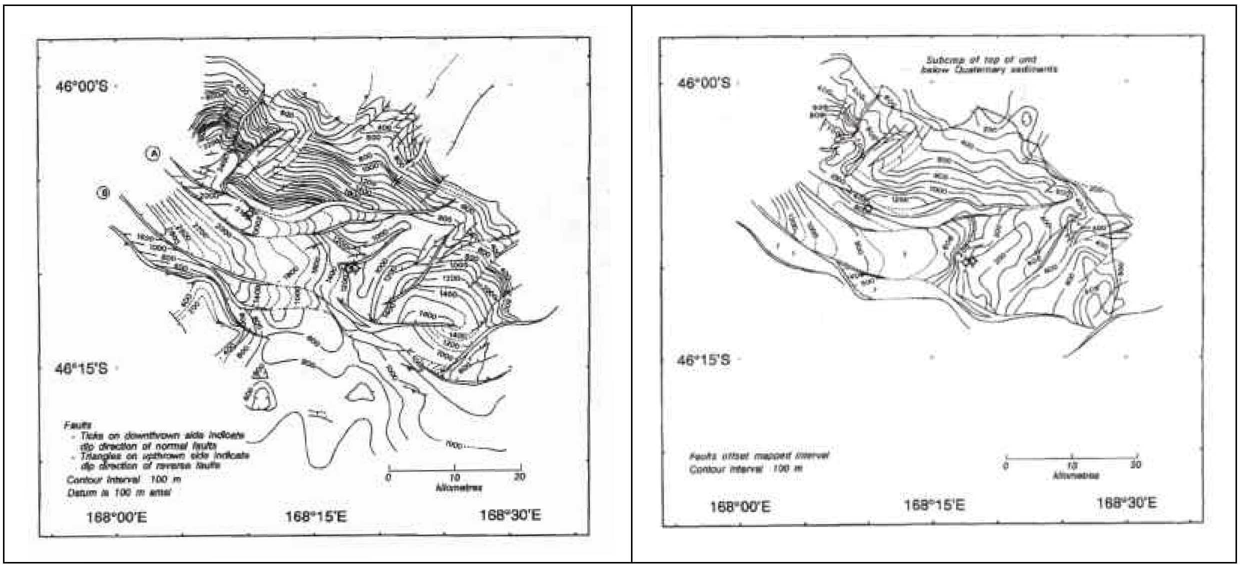


Figure 3.19: Results of seismic mapping Winton Basin (Cahil, 1995). Basement structure map (left) and isopach of early Oligocene to late Eocene sediments (right).

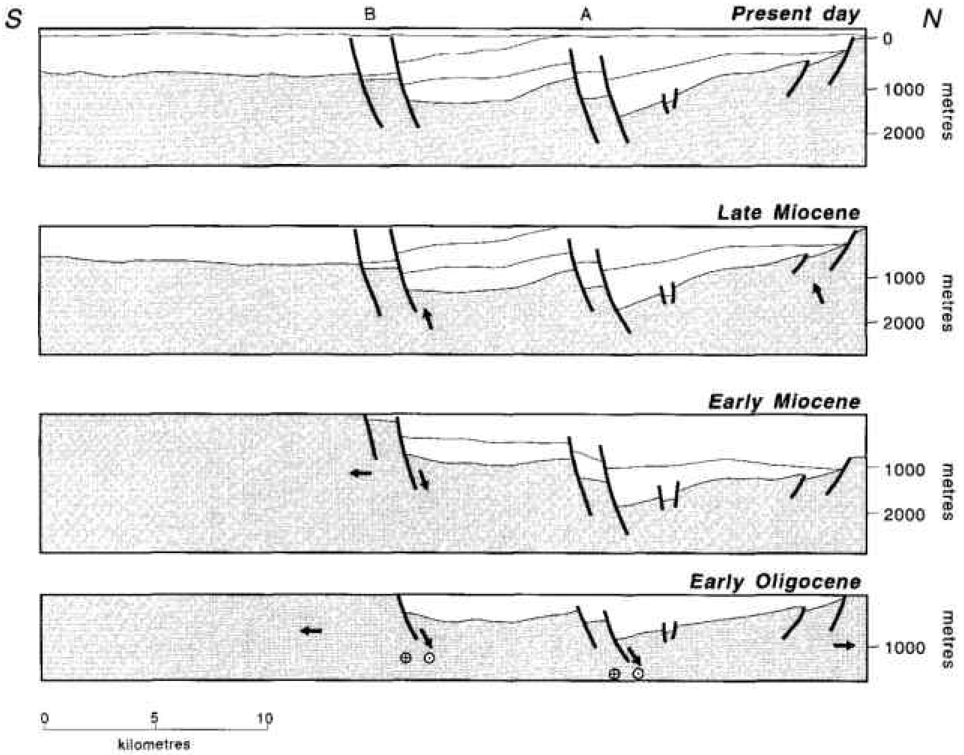


Figure 3.20: Structural model of the onshore Winton Basin half graben evolution over time (Cahil, 1995).

Eocene sediments of Happy Valley-1 (Waiau Basin) were deposited in a similar sedimentary environment in the vicinity of the Winton Basin. Properties which are assumed for Winton Basin were taken from the Happy Valley-1 Water Condensate Ration (WCR).

Reservoir properties:

Reservoir thickness: 150m Gross / 50m Net

Porosity (PHI): 11% average, peaks at about 16% (from WCR Happy Valley-1, PR1382, 1988)

Porosity (K) estimated from literature data: 25 mD (assumed range in model: 5-100mD)

Although no analysis of water samples are available, formation water is considered to be fresh: 2600ppm NaCl eqiv., WCR Happy Valley-1, log interpretation).

Conclusion:

The seismic interpretation published by Cahill (1995, Figures 3.19 and 3.20) is mainly based on reprocessing the 1986 seismic survey (compare Figure 3.17, blue lines). All existing 3 wells were drilled on structural high positions and did **not** test the possible graben fill play which is highly speculative.

To test the presence of this play, some 2D seismic would be required for well placement reasons before drilling a stratigraphic well. Prior to these scoping, models are required to examine the upside.

The play comprises the deep saline aquifers of the Late Eocene Mako Formation. This succession has been interpreted as a terrestrial fill of half grabens developed during the Late Eocene (shale, sandstone, and lignite). A regional seal exists i.e. thick marine transgressive mudstones of the Oligocene Winton Hill Formation.

The South Island is relatively underexplored in terms of fundamental geological information so a more comprehensive (and expensive) exploration program would have to be undertaken to reach technical and regulatory certainty on a CO_2 storage site for passing FID into full field development.

3.4.1 High level stage-gated CCS project exploration scheme – SOUTH ISLAND:

- Screening study. Data mining, review of publicly available data and check of accessibility and ownership
- Scoping modelling study based on available data (containment / capacity / injectivity)
- 2D seismic survey (3 lines perpendicular to the boundary faults of the half grabens) for well placement
- Drilling of at least 3 exploration wells (stratigraphic test) to prove the conceptual model (half graben-fill with fluvial sandstones) and understand sedimentary environment and geometry of the graben filling (see figures. 3.18 and 3.20). Hydraulic properties of the target horizons has to be tested
- Drilling of an appropriate number of appraisal wells (due to results of hydraulic testing of the exploration wells) with proper completion and diameter as injection wells

Recognising the that Winton Basin is relatively underexplored compared to the publicly available data that exists on the Northern Island (within a producing hydrocarbon basin), the exploration seismic for the Winton Basin is more comprehensive and thus more costlier than the necessary program for Case Study 1 on the North Island.

Table 3.21: Seismic Program nominally required for South Island Storage – Winton Basin

No	Cost Component	Indicative Cost Estimate (mil USD)
1	2D reprocessing	0.03
2	Mobilization/demobilization	0.75
3	2D Acquisition	2.70
4	2D seismic Processing	0.04
5	Mobilization/demobilization	0.75
6	3D Acquisition	30.00
7	3D Processing	0.30
	Total	34.57

Table 3.22: Reservoir Parameters for Winton Basin Storage Site

Reservoir Parameters		UOM	South Island
1	Mid-formation Depth	m	1750
2	Initial Pore Gradient	psi/ft	0.443
3	Temperature Gradient	C/100m	3.2
4	Permeability	md	25
5	Net Thickness	m	50
6	Porosity	v/v	0.11
7	Virgin Fracture Gradient	psi/ft	0.75
8	Injection Pressure Limit (of FG)	%	90%
9	Relative Permeability	-	0.15
10	Drainage Radius	m	2500
11	Wellbore Radius	m	0.11
12	Total Skin	-	5
13	Boundary Type	-	Partially Closed
14	Pore Pressure Escalation (30y) - relative to $P_{pore,initial}$	%	50%
15	Techton. Stress Grad.	psi/ft	0.18

Table 3.23: Storage Parameters for CCS Project South Island

Storage Project Parameters		UOM	South Island
1	Annual Mass Rate	mil tonne/y	4
2	Injection Period	y	30
3	Injection Commencement	-	2016
4	Total CO_2 Mass Stored	mil tonne	120
5	"Pancake" Areal Coverage (E~ 10%, Swir ~ 50%)	km2	606
6	CO_2 Density at reservoir conditions	kg/rcm	720
7	Radius (Pancake model)	km	14

Table 3.24: Injection Parameters and Well Requirements for Winton Basin

Pseudo-Steady State CO_2 Injection Rate		UOM	South Island
1	Initial Injection Rate (Year 0)	tonne/d/well	785
2	Final Injection Rate (Year 30)	tonne/d/well	467
3	Initial Injection Well Requirement (Year 0)	-	14
4	Final Injection Well Requirement (Year 30)	-	24

Table 3.25: CAPEX/OPEX Requirements for South Island Storage

Summary of Expenditures		UOM	CASE 2
1	CAPEX (Nominal)	mln A$	$ 392
2	OPEX (Nominal)	mln A$	$ 388
3	Total Expenditure (Nominal)	mln A$	$ 780
4	CAPEX (Discounted)	mln A$	$ 186
5	OPEX (Discounted)	mln A$	$ 69
6	Total Expenditure (Discounted)	mln A$	$ 256

The well sequencing is shown overleaf. For the South Island Case Study, we start with 14 injector wells and finish with 24.

Figure 3.26: Well Sequencing for Winton Basin Storage

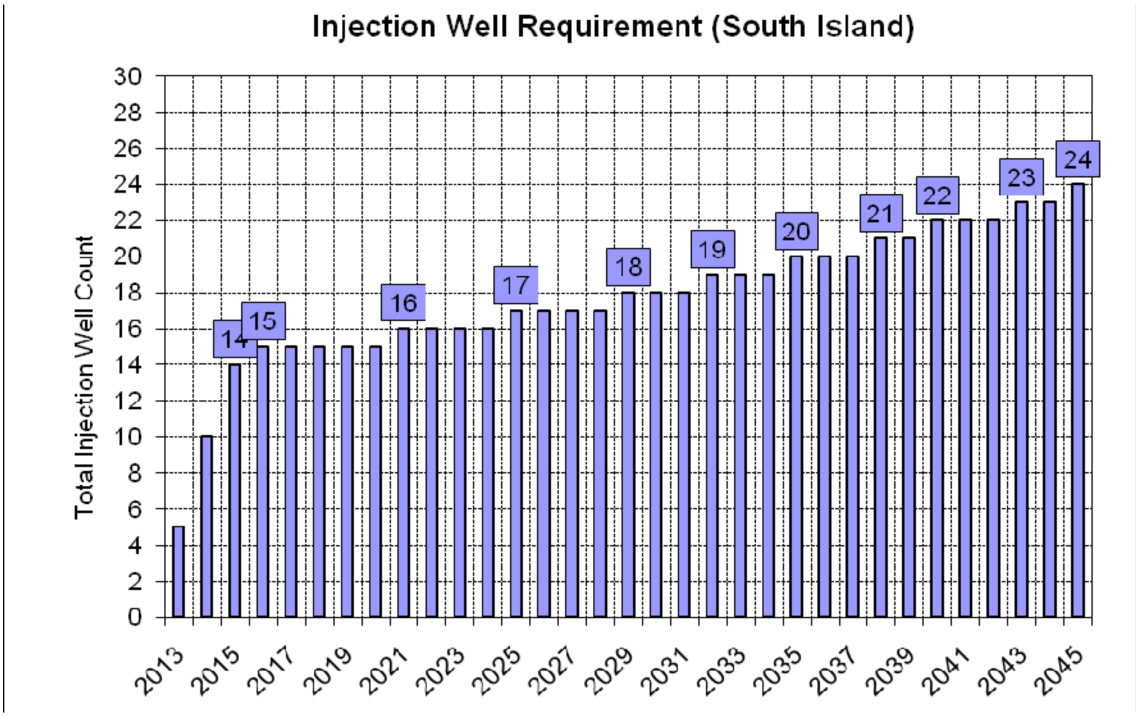


Table 3.27 Well cost assumptions for both case studies

Financial Parameters		UOM	North Island	South Island
1	Deep Monitoring Well Cost	mln A$/well	$ 7.5	$ 5
2	Deep Monitoring Well Count	well	3	7
3	Shallow Monitoring Well Cost	mln A$/well	0.5	
4	Shallow Monitoring Well Count	well	5	13
5	Injection Well Cost	mln A$/well	$ 10	$ 7.0
6	Inj. Well Abandon/Rehab Cost	mln A$/well	1	
7	Mon. Well Abandon/Rehab Cost	mln A$/well	0.5	
8	In-field Flow Lines	mln A$/well	0.25	
9	Control System	mln A$	5.0	
10	Field Road and Access	mln A$	5.0	
11	Drilling Cost Escalation	%/yr	0%	
12	Well -related OPEX	% of Cum.DrillEx	5%	
13	Monitoring OPEX	mln A$/yr	0.25	
14	Fees & Rents OPEX	mln A$/yr	0.25	
15	Discount Rate	%	10%	

Note that there is no drilling cost escalation built in here and that the differences between the well costs in the North and South Islands is a function of the total depth (North Island is drilled to 2750m, South Island to 1750m).

3.4.2 Summary – South Island Case Study Storage

In terms of the CO_2 storage project on the South Island, the reservoir assumptions show lower permeability and lower porosity than the North Island and a higher well count will be needed to inject the 4MT CO_2 per annum (final total of 24 wells). **It must be stated that a 4MT per annum injection project in New Zealand, operating in 2016 would be amongst the world's biggest CCS projects.** Gorgon in Western Australia will be injecting between 3.5 to 4MT pa. A number of other reservoir characteristics have been assumed as identical between the North and South Island case studies and are thus, gross simplifications of real reservoir conditions which are unknown at this stage. Overall, the discounted cost of storing a tonne of CO_2 is similar in both cases at approximately A$10 which shows that the storage costs will be relatively minor contributors to the full CCS cost of a project. However, such a statement must be read with caution that the assumption being made here is that the exploration and appraisal program that must be undertaken to prove up the sites, works perfectly and that the exploration wells can be re-used as both injection and monitoring wells, so there is no 'lost' exploration funds exhausted on sites that prove technically unsuitable for CO_2 storage.

3.5 Conclusions

Only 'proven' geological storage options into saline aquifers or depleted oil and gas reservoirs were considered and not any potential EOR/EGR or ECBM options that could provide an offsetting economic benefit of carbon capture through beneficial re-use. ECBM still has a number of technical issues that need to be solved prior to the implementation on large scale CCS project though progress is being made, notably in the US. Likewise, for the North Island case study it was assumed that there is no impact on existing production operations by simultaneous injection of CO_2 (sim-ops) and that the block offered is suitable for CO_2 injection and that these 'sim-ops' are accepted by other title holders nearby. From a rational point of view in avoidance of 'sim-op' issues, a 'greenfield' project in the South Island could make more sense.

Realistically, a storage project in New Zealand would need to be an integral part of a full chain CCS project and opportunities for common user infrastructure development to reduce costs through economies of scale may not materialise. The more fundamental decision for New Zealand, given the relatively low contribution of fossil fuels to its emissions profile and the high cost of CCS, revolves around the political appetite to undertake a CCS project.

Depending on the priority given to CCS by the New Zealand Government within its emissions reduction strategy, the next steps would be to undertake further fundamental exploration to reduce uncertainties around the technical performance of potential CO_2 storage sites, particularly on the South Island and to understand migration boundaries for CO_2 thus allowing gazettal of CO_2 licences of suitable size. Should storage operations be considered on the North Island then consideration will need to be given to the potential overlap between CO_2 storage operations and existing (and future) hydrocarbon operations. However, it must be emphasised that significant expenditure will be incurred in the future 'finding' costs for a suitable storage site and a means of funding these must be determined, either by Government alone or in partnership with industry stakeholders.

3.6 References

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3.7 Abbreviations/Glossary [58,59,60]

3-D seismic: A method of displaying a three dimensional-image of the Earth's subsurface as created by the interpretation of the seismic data that have been collected through numerous seismic surveys run in a grid pattern. 3-D seismic surveys display more detailed information on the subsurface than do conventional surveys and contribute significantly to field appraisal, exploitation, and production.

Brine: Salt-saturated water that that occupies the pore spaces of sedimentary rocks, essentially, concentrated sea water.

Cap rock: A comparatively impermeable rock layer overlying a reservoir rock that keeps the reservoir fluids from escaping upward.

Clastic: Pertaining to a rock or sediment composed of broken fragments derived from pre-existing rocks. For example, quartz sand is a clastic sediment, and quartzose sandstone is a clastic rock.

Core: A cylindrical section of rock, typically anywhere between 1 and 6 inches in diameter and between 1 inch and several tens of feet long, cut in a borehole using specialized drilling tools. There are two basic types of cores, full-barrel core and sidewall core.

Deep Saline Formation – Sandstone and carbonate (limestone or dolomite) rocks with void spaces inhabited by salty water.

Depleted Natural Gas Reservoir – Once the formation has been stripped of its natural gas, it essentially behaves like a deep saline formation in terms of CO_2 storage.

Depleted Oil Reservoir – Once the recoverable oil has been produced from the formation, CO_2 may be stored in the available pore space and/or CO_2 injection can also be used to recover additional oil that was left behind during primary production.

Enhanced oil recovery (EOR): A method of stimulating crude oil production in a “depleted” reservoir by injecting another fluid such as water, steam, chemicals, or carbon dioxide into the reservoir. The injected fluid helps loosen the oil from pore spaces in the rock and flushes the oil to a nearby borehole while taking the place of the oil in the pores.

Graben: A relatively low-standing fault block bounded by opposing normal faults. Graben (used as both singular and plural) can form in areas of rifting or extension, where normal faults are the most common type of fault. Between graben are relatively high-standing blocks called horsts. A half-graben is a downdropped block bounded by a normal fault on only one side.

Geologic Storage – Underground storage or sequestration of carbon dioxide or other greenhouse gas in a reservoir, including an EOR reservoir.

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[58] Glossary Definitions are taken from “ASSESSMENT OF RISK, LEGAL ISSUES,AND INSURANCE FOR GEOLOGIC CARBON SEQUESTRATION IN PENNSYLVANIA” 2009 available at http://www.dcnr.state.pa.us/info/carbon/assessmentrisk-ccs.pdf

[59] http://www.dcnr.state.pa.us/info/carbon/mastercstareport2.pdf

[60] http://www.glossary.oilfield.slb.com/

Injectivity: The rate and pressure at which fluids can be pumped into a formation without fracturing the rock.

Millidarcy: A measurement unit of permeability; one thousandth of a darcy. A darcy is defined as the measure of the flow of 1 cubic centimetre per second of a fluid with a viscosity of 1 centipoise under a pressure gradient of 1 atmosphere per centimetre acting across an area of 1 square centimetre.

Permeability: The capacity of a reservoir rock to allow fluids to pass through it, expressed in millidarcy.

Porosity: The ratio of the volume of the pore space within a reservoir rock to the volume of the whole rock, generally expressed as a percentage.

Seal: An impervious rock adjacent to a reservoir rock in the subsurface that acts as a barrier to the passage of migrating fluids.

Trap: Any barrier to the movement of oil, gas, or water, thus allowing the fluid to accumulate in a reservoir.

Attachment 4
Stakeholder Review (Social Impacts)

4. STAKEHOLDER REVIEW

4. STAKEHOLDER REVIEW

4.1 Introduction

As part of the Transfield Worley led consortium, CSIRO is pleased to present the findings of the social research component. The aim of this component was to investigate the social impacts that would need to be resolved if *New Zealand were to deploy a commercial Carbon Capture and Storage Facility.*

Similar to many countries New Zealand is facing serious challenges around security of supply, particularly in the oil and gas arenas, alongside rising greenhouse gas emissions (IEA, 2006). Carbon dioxide capture and storage (CCS) provides an opportunity to reduce emissions from fossil fuel generated power and other industrial processes and therefore is being considered as a possible solution for the longer term.

However as a new and emerging technology, CCS remains relatively unknown across a wide cross section of society. With a number of perceived risks that cause concern for the uninitiated and a high cost associated with the technology, both in terms of the financial investment required and the energy penalty it brings, a social assessment of the issues was considered a priority as part of this early research.

To identify the issues, CSIRO undertook a series of interviews with a range of stakeholders across New Zealand to determine the potential social issues associated with implementing CCS in New Zealand. In addition, it is worth examining the risk communication literature to inform why engagement on CCS will be critical in moving the technology forward.

4.2 Theoretical Considerations

Research in the area of risk has shown that issues which are of most concern to consumers are those that will have a direct effect on their lives and those of their friends and families. These issues include personal security and safety, financial security now and in the future, and health and well-being (Slovic, 2000; NCC, 2002). However, how an individual reacts to risk is complex and diverse. Factors which influence reactions include the disposition of the consumer, the type of risk, the risk outcome and external influences (Slovic, 2000).

A key issue for technology deployment is how the risks that are associated with the technology are perceived. Most often, risk perceptions of the public are intuitive risk judgements. These perceptions are based on social and cultural factors of human behaviours (Slovic,2000). According to Slovic, perceptions of risks are heightened when the risk is unknown, catastrophic and uncontrollable. Conversely risks are perceived as lessened if they are known, limited in risk and controllable. The outcome can contribute to a heightened sense of risk if it is irreversible or potentially devastating, may be felt immediately and affects other people. Similarly the nature of risk will be influenced by whether the hazard (technology) is agreed upon by those facing it or it is imposed by others.

Additionally, the literature demonstrates that people can accept risks if there are tangible benefits associated with them (Fischoff & Fischoff, 2001; Slovic, 1993; Wilkins, 2000). More often, new and emerging industrial technologies are likely to be viewed as high in risk, low in benefit and less acceptable. This appears to be the case with CCS where the major benefit from implementing CCS is as a mitigation technology where the positive effects will be felt globally. However, the majority of the risks are far more local in nature (Kuijper, 2009). When individuals most affected by the proposed project are the individuals less affected by the problem, policymakers face an even greater challenge in bringing about positive acceptance of a new project.

Risk communication has evolved to a point where there are now well established ground rules for those communicating about risk. According to Fischoff (1991), there has been a transition from one way information provision, with a gradual move towards a two-way communication process. This is best demonstrated from Fischoff's paper in the steps outlined below:

- All we have to do is get the numbers right
- All we have to do is tell them the numbers
- All we have to do is explain what we mean by the numbers
- All we have to do is show them that they've accepted similar risks in the past
- All we have to do is show them it's a good deal for them
- All we have to do is treat them nice
- All we have to do is make them partners
- All of the above.

The above hierarchy will be very relevant to any efforts made by various proponents of CCS if it is to be deployed successfully in any identified area.

4.3 Methodology

Information contained is this report was gained through nineteen (n=19) telephone interviews with a range of stakeholders. These interviews comprised a semi-structured format, allowing participants to discuss the issues they thought were important, as well as guiding the discussion across a number of topics.

4.3.1 Research Participants

Research participants were sourced via referral from a range of key stakeholders and desktop research. The interview list was progressively extended as the interview process unfolded. A deliberate effort was made to include a diversity of opinions. Following a 'gradual sampling' approach, more participants were interviewed until no substantially new material seemed to be emerging. Thirty-four (n=34) participants were contacted – of these 4 declined and 11 were either out of the office, referred another person to be interviewed, or did not respond. Of these, several participants were identified to focus on regions suggested in the case study, however to date there has been no real differences between the various regional locations. Figure 4.2 shows the geographical spread of interview participants and all participants that were interviewed are listed in Table 4.2 below.

Table 4.2 List of interview participants

Participant	Background
Industry and NZCCS partnership	
Chris Baker	Coal Association of New Zealand
Alan Melhuish	Genesis Energy
Kirsten Ferguson	Solid Energy
Paula Hunter	MWH NZ Ltd
Dr Trevor Matheson	CRL Energy Ltd.

Participant	Background
George Hooper	Centre for Advanced Engineering, New Zealand
Government/Regional councils	
Nathan Bittle	Analyst, Energy & Communications Branch, Ministry of Economic Development
Mr Tara Ross Watt	Maritime New Zealand
Catherine Leining	Climate Change Policy Team, Ministry for the Environment
Keith Brodie	Environmental monitoring manager, Taranaki Regional Council
Stephen Canny	Group Manager, Enterprise and Strategic Projects, Venture Southland (a enterprise development initiative of the Invercargill City Council, Southland District Council and Gore District Council)
Community and NGOs	
Buddy Mikaere	Principal, Buddy Mikaere and Associates
Simon Terry	Executive Director, Sustainability Council New Zealand
Harvey Bell	Secretary, Federation of Maori Authorities
Peter Hardstaff	Climate Change campaigner, WWF New Zealand
Dr. Eric Jansseune	Representative, Engineers for Social Responsibility & Repower NZ Coalition
Don Nicholson	President, Federated Farmers of New Zealand
Fraser Clarke	CEO, New Zealand Wind Energy Association
Scott Blain	Local area representative (Taranaki, Wanganui, Manawatu) Association for Consulting Engineers New Zealand (ACENZ)

Figure 4.2 Map showing location of interview participants

4.3.2 Interview Questions

Prior to the interviews, the following twelve interview questions were sent to participants, to give them time to consider their responses. These questions were generated by the research team as most appropriate for the focus of the research.

1. Please tell me a bit about yourself, your current role and background?
2. How would you describe your knowledge and experience of CCS?
3. What are your thoughts about the potential for CCS in New Zealand a) as a source of low emissions energy? and b) as a factor in New Zealand's future economic development?
4. What do you think are the key benefits that could be gained through using CCS in New Zealand?
5. What do you see as the key risks regarding CCS?
6. What objectives would you like to see achieved if CCS was adopted in New Zealand? (i.e. what things do you think it *should* achieve?)
7. If CCS was to be developed in New Zealand, what do you think should be the role of government, industry and research bodies in its development and management?
8. In your opinion what do you think the key social and cultural issues will be in New Zealand if CCS was to be developed?
9. Do you think current approaches to community engagement practiced by government/industry/research organisations in New Zealand are adequate to deal with these issues?
10. Is there anything else you would like to add on the potential for CCS in New Zealand?
11. Can you summarise for me what you see are the main points of our discussion today?
12. Is there anyone else that would be relevant to this research who I should be talking to?

Recognising that some participants may not be familiar with CCS, a brief definition was obtained from the New Zealand Ministry of Economic Development website and was kept on hand to provide to participants if required.

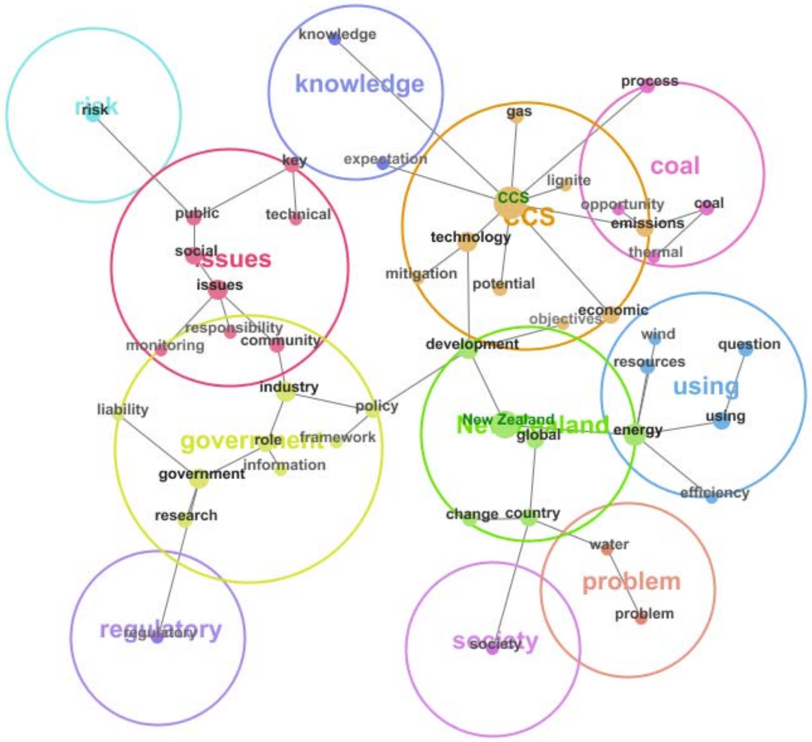
"Carbon dioxide capture and storage – also known as geosequestration – is a process whereby CO_2 *is captured from large point sources, compressed, transported and injected into deep geological formations for permanent storage"*

4.3.3 Data analysis

Of the 19 interviews, 18 were audio-recorded and transcribed with one participant declining to be audio-recorded and so hand-written notes were analysed instead. Data was analysed in two ways. The first used the software application NVivo, which allows researchers to review and 'code' written text to identify and classify overarching themes identified by the researcher. Such research is appropriate for a preliminary review of the knowledge and perceptions of stakeholders in relation to carbon capture and storage as it allows a rich, naturalistic exploration of people's thoughts and feelings and the assumptions and values which underlie these.

The second approach used Leximancer software, a discourse analysis package that allows researchers to identify frequently used words and their connections with other words. Leximancer then consolidates this into meaningful themes and concepts and then maps their associated relationships. Themes are represented in the map as colour circles surrounding clustered groups of concepts and tagged with a coloured theme name. Concept clustering is determined by frequency and proximity of lexis (total word stock) within the data set. Where concepts occur within more than one theme the degree of frequency is represented by the level of overlap of theme circles. The strength or weakness of a theme is represented by the intensity of the colour of the theme. This is also the case with regard to connectivity, the brighter and more intense the colour the stronger the connectivity. Figure below highlights themes and concepts identified through Leximancer from interview data collected for this report.

Figure 4.3 Leximancer map - themes and concepts



Both analyses were triangulated to identify the major themes that arose from the interviews that had been conducted and the findings are outlined in the following section.

4.4 Findings

The key themes to emerge as a result of triangulating the data are presented in this section under the headings of ‘knowledge of CCS’; ‘feasibility of CCS’; ‘viability of CCS’; ‘perceived opportunities for CCS’; ‘views on the future of CCS”; and ‘potential social and cultural issues”.

Given the questions posed, it is not surprising that both feasibility and viability were key emerging themes; however to avoid confusion, it is worth differentiating their meanings within the context of this report.

Feasibility is described as:

> *“Capable of being accomplished or brought about; possible.”*

Viability on the other hand being described as:

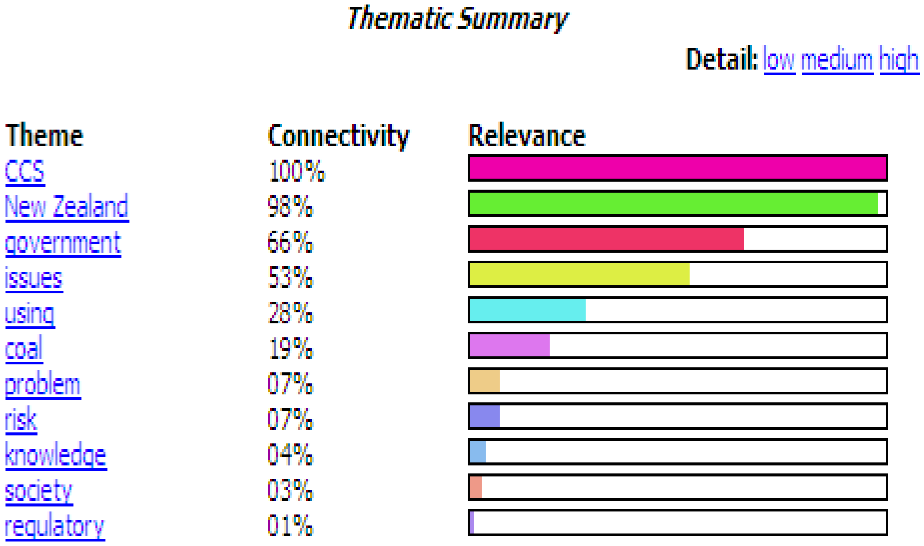
> *"Capable of success or continuing effectiveness; practicable:"*

Source:http://www.thefreedictionary.com/

Therefore, for the purposes of this report, feasibility refers to what physically can be accomplished while viability examines the economic imperatives and trade offs that must be examined when identifying whether CCS has a role within the New Zealand context.

Lexical analysis resulted in 11 primary themes being identified from within the data set. Leximancer lists these themes in the Thematic Summary table below (Table). With a 100% connectivity and relevance, CCS is the referral theme, or anchor, used to determine the level of connection and relevance for each of the remaining themes. Relevance reflects as a percentage the number of times a concept appears against the occurrence of the most commonly occurring concept, in this case CCS. Though not directly reflecting earlier identified themes, lexical themes are representative of the clustering of concepts, or frequently occurring words, within the data set. A ranked list of the concepts forming lexical themes can be found in Appendix A.

Table 4.4 Leximancer thematic summary



Thematic Summary

Detail: low medium high

Theme	Connectivity	Relevance
CCS	100%	
New Zealand	98%	
government	66%	
issues	53%	
using	28%	
coal	19%	
problem	07%	
risk	07%	
knowledge	04%	
society	03%	
regulatory	01%	

4.4.1 Knowledge of CCS

The first two questions explored individual stakeholder's experience and knowledge of CCS. These questions were designed to explore the information needed by stakeholders to effectively evaluate the suitability of CCS in the New Zealand context.

Of all the stakeholders interviewed, industry and government representatives reported the most extensive knowledge of CCS. However, many qualified that their experience of CCS in the New Zealand context was relatively limited. These stakeholders also tended to describe their understanding of CCS mainly at a strategic or policy level rather than a technical one. More specifically, that their knowledge was focussed on CCS in an international context rather than a national one. Leximancer analysis supports this finding as can be seen in Figure which identifies direct links between the concept 'knowledge' and other concepts within various themes. The strongest conceptual links observed being with CCS, New Zealand and government, followed closely by risk, and process, CCS was generally described by industry and government stakeholders in terms of its potential for reducing carbon emissions from industrial processes, for example, “monetising lignites” or a “coal to liquids project” rather than for power generation itself.

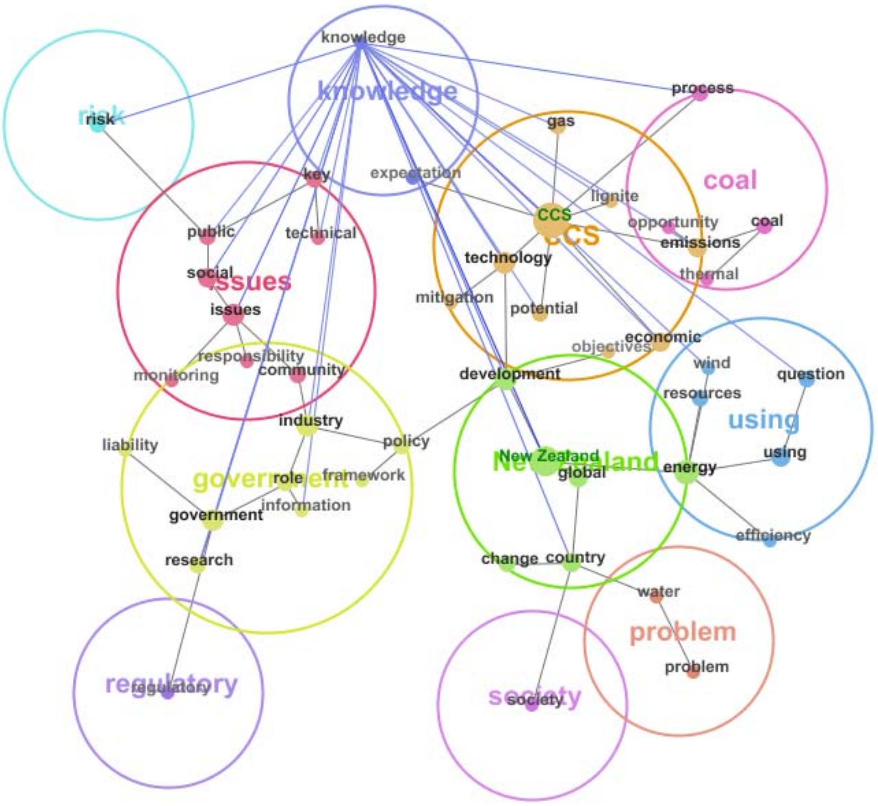
> *Well I haven’t had much experience because we haven’t done much … in a strategic and kind of practical level [it’s] reasonably high. In a detailed technical level, I wouldn’t look to me to design a facility!*

No community or NGO stakeholders described their knowledge of CCS as extensive. Instead they spoke in terms of their knowledge being ‘basic’ or ‘limited’ and based on what is discussed in the media. It was evident that most community and NGO stakeholders understood that CCS was an option for reducing carbon emissions, but there were many misperceptions as to how this is done.

In particular, some lacked an understanding of CCS as a point-source technology. It was thought by one stakeholder that CCS could be used to provide a source of local energy to heat people’s home. Most commonly, stakeholders confused CCS with other CO_2 mitigation options such as bio-sequestration, CO_2 storage in soils, and others.

> *[My knowledge is] probably fairly generic not specific but, it's something I’ve also done some work on because…a friend of mine has got a client who has just signed up for a technology that is supposed to be able to remove the carbon out of CO_2.*

Figure 4.5 Leximancer map – knowledge



4.4.2 Feasibility of CCS?

An Unproven Technology

The question of whether CCS is a feasible technology for New Zealand is in some ways a natural extension for those who do not have enough information about CCS. Almost all community and NGO stakeholders said they had a working idea of the principles of CCS but were unsure how it was feasible technically.

> *Well, my understanding is that carbon capture and storage is an unproven technology, so … I don't know what its character is because nobody knows whether it works or not, so 'who knows?' is the answer to that question.*

Stakeholders recognised that although CCS technology was gaining major attention at the highest levels of government internationally the challenge of demonstrating CCS at commercial scale left some doubts as to whether its deployment would ever be realised.

Has a Number of Risks

Another major theme evident in the interviews is that CCS is seen to have a number of risks. Not only as an extension to the fact that it is unproven at commercial scale, but also the potential for seismic events and leakage from the reservoirs, were commonly mentioned by stakeholders as risks associated with CCS. New Zealand's unique geology and seismic risks were often cited as a reason that exacerbated the potential for CCS to be feasible within the New Zealand context.

> *It's not called the Shaky Isles for nothing.*
>
> *My kind of layman's understanding of gas is that it's not that easy to store, 'cause it's inherently leaky sort of stuff*

Leakage is a common concern that is raised by most individuals when they first hear about CCS. Concerns can range from the risk of human life and associate health effects through to the potential of causing serious harm to ecosystems. Particularly, whether storing of carbon dioxide underground would contaminate ground water was something that was clearly a concern for many.

In support of the above analysis, the Leximancer map in

Figure 4.6 demonstrates a minor thematic overlap between risk and issues and a more substantial overlap between issues and government. Strong conceptual links can be seen between the concepts risk, CCS, government and New Zealand across several themes. Whereas the concept social, is depicted as having the strongest link, whilst community, public, technical and responsibility can also be directly linked to risk.

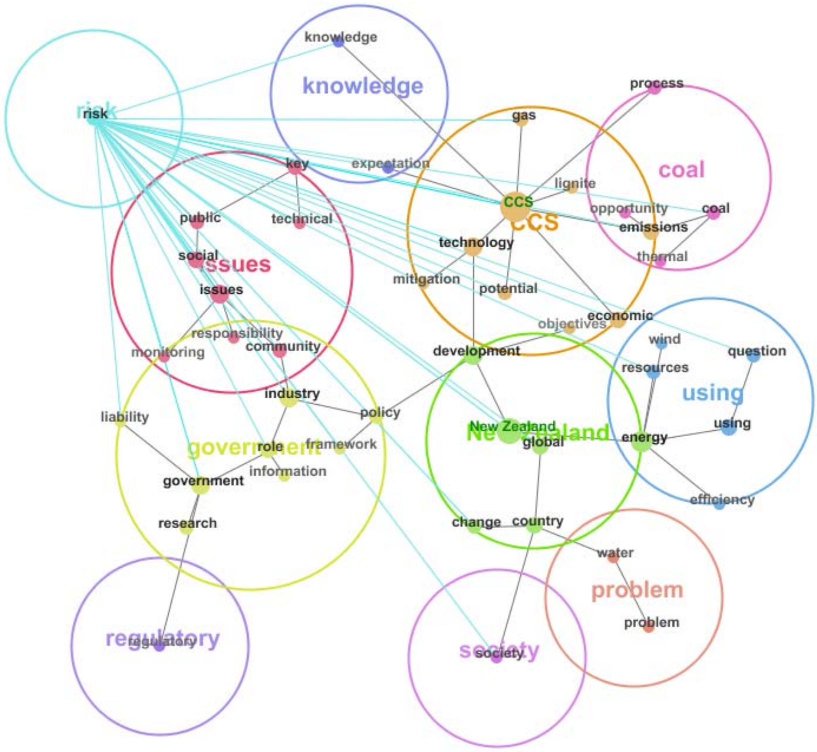


Figure 4.6 Leximancer map - risk

Adequate Storage

In relation to the feasibility of CCS, a prominent question raised by stakeholders was whether there would be adequate on-shore storage sites available in New Zealand. Further, it was highlighted that as old gas sites became depleted there was an opportunity for storage however the number of these that existed in New Zealand was thought to be quite limited.

> *In my conversations with oil industry people, talking about the potential for the Maui field to be reinjected, their initial thoughts were that the temperatures are too high and the pressure's too great, and it wouldn't actually be practically possible in reality.*
>
> *The impression that I've had from the strategic meetings that I've attended is that the CCS potential in New Zealand is somewhat limited by our geography.*

Limited Applicability in New Zealand

All of the above led several stakeholders to perceive that CCS had limited applicability in a national context. New Zealand's relatively low CO_2 emissions from energy and unique geology were factors that influenced this perspective.

> *I'm actually a bit pessimistic in respect of the future of CCS in New Zealand actually from a personal point of view ... CCS has got a big role to play globally, but I think New Zealand is very unique …*
>
> *.. from my professional experience and exposure to it, it doesn't sound like there's an awful lot of confidence that it's an option for New Zealand.*

4.4.3 Viability of CCS?

The interview data also indicates a need to understand the reasons why CCS is being considered in the New Zealand context. This was particularly evident with those stakeholders not directly involved in CCS development in New Zealand.

> *If it was to be something that the nation [wanted to do]…. we'd be wanting to see some pretty clear and compelling reasons why…*

Financial imperative

Several stakeholders stressed the importance of understanding the financial imperatives for CCS including use of rigorous cost/benefit analyses and appreciating the interplay between existing electricity markets and energy generation options, compared to that of CCS. These findings are similar to earlier research results reported by Wright et al. (2007).

> *…all of a sudden, there's a better innovation somewhere else that says this carbon capture and storage was a dumb idea….. There's a cheaper system somewhere else that does exactly the same thing….*
>
> *I don't see how you can do anything serious on CCS without... electricity market analysis. So particularly on the cost side and only then after you've gone through all that and looking at bio-sequestration, could you in any way have an idea as to the strategic and economic place of CCS within the broader framework.*
>
> *So given where the likely costs of are, particularly in the near future, although I guess over time they will decline as more experience is gained, that would, in my view, price for the electricity sector, is out of the game.*

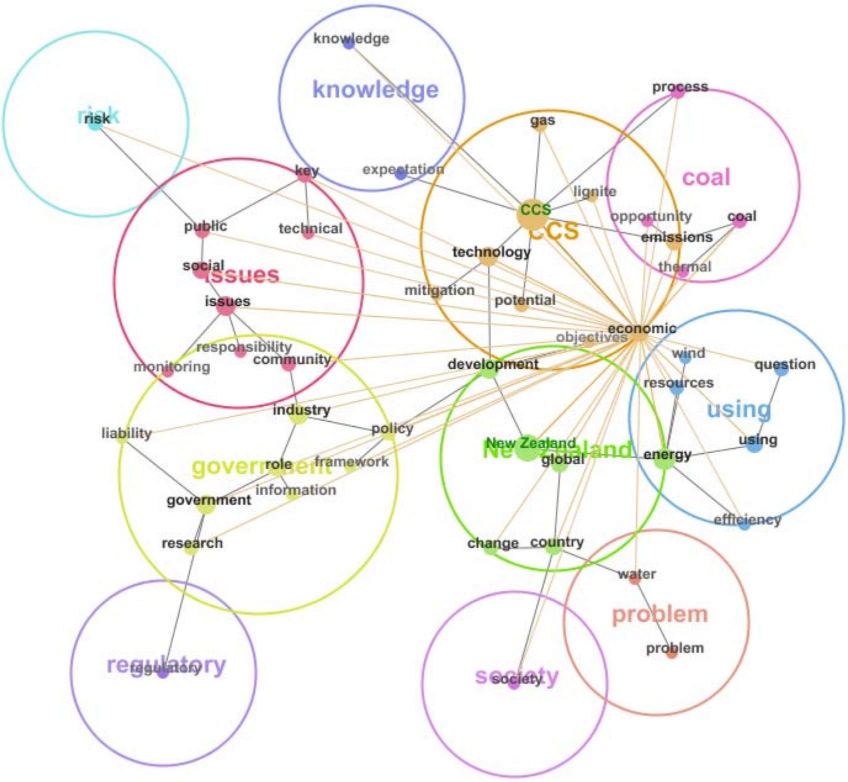
Addressing the issue of the size of investment required for CCS will need careful attention if CCS is to be considered past this conceptual stage for New Zealand.

Costs associated with developing CCS in a sector already dominated by renewable energy sources such as wind and geothermal were also considered as reasons for CCS not having a large part to play in New Zealand's energy resources future.

> *…Seventy to eighty per cent of our electricity is generated from renewable sources…the abundance of renewable energy options… given what the likely costs of CCS are, particularly in the near future… that would in my view price CCS for the electricity sector, out of the game.*

The Leximancer map in Figure 4.7 supports these findings with strong thematic overlaps across several themes including CCS, Coal, New Zealand, problem, using, and society. Strong conceptual links are evident between economic and CCS, New Zealand, change, technology, energy and coal. Less significant links can be seen with wind, thermal and resources.

Figure 4.7 Leximancer map - economic



Greenhouse Gas Emissions

Stakeholders sought an understanding of the unique contribution CCS could make toward reducing carbon emissions in New Zealand and how it would fit within the nation's portfolio of climate change mitigation solutions. Some stakeholders felt that if New Zealand could sequester large amounts of carbon dioxide, then the technology would be worthwhile. This was specifically considered given the perceived unique nature of New Zealand's emissions being, to a substantial degree, agriculturally derived, which are often seen as more difficult to deal with for mitigation.

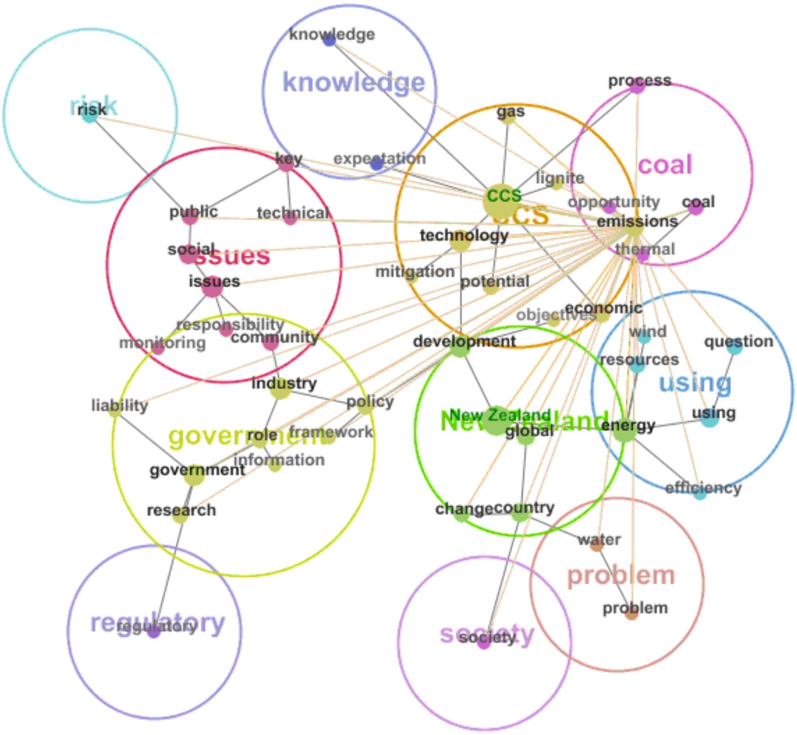
> *Anything that we can do that reduces our emissions because of the unique profile of New Zealand's emissions, nearly half our emissions we can't really do anything about at the moment because it comes from [a] budget of systems of animals, farmed animals. So, every technology that is available to minimise greenhouse gas emissions has got to be positive*

The global need to reduce CO_2 emissions was cited as another reason for New Zealand to consider CCS. Although it was recognised that New Zealand did not contribute large amounts of carbon dioxide in comparison to other countries some participants felt that there was a 'public good' element in being part of the global solution to mitigate carbon dioxide emissions.

> *…we would embark on CCS because of the societal need and global need to address the problem of climate change and we try to address it by reducing the emissions of greenhouse gasses. That's a societal issue to get to grips with and we're miles from getting to grips with it now.*

The leximancer map in Figure identifies links between the concepts emissions government, New Zealand, economic, energy, CCS and problem. Thematic overlaps between CCS and coal further highlights the positioning of the concept emissions as relevant. These findings may be seen to support the question of energy security and the potential for CCS with the New Zealand context, and the role that government would have to play.

Figure 4.8 Leximancer map – emissions



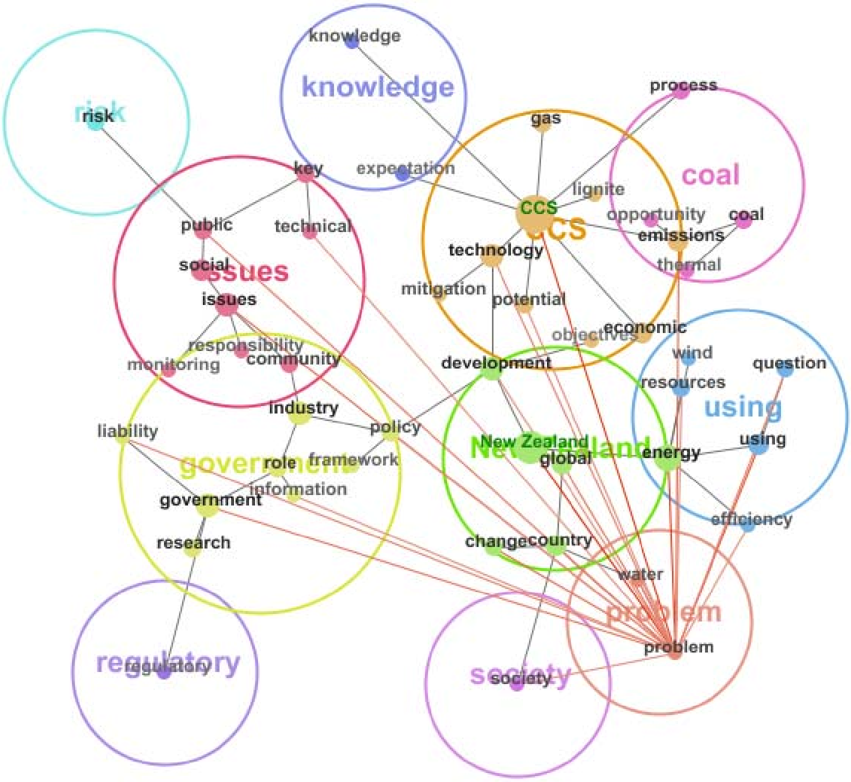
Does not address the 'real' problem

Some participants saw CCS as not addressing what they saw as the ‘real problem’ with respect to climate change and greenhouse gas emissions - the need to address energy efficiency to combat climate change. In this instance, CCS was described as an ‘end-of-pipe’ technology. There was scepticism expressed by community and NGO’s regarding the association between CCS and coal mining and coal-based energy generation.

> *…for me, the main issue associated with CCS is associated with burning coal. So if you get to a point where you’re storing the CO_2 emitted, capturing it and storing it, and that’s all fine and viable and economically sound and all the rest of it, you’re still digging up coal and the associated impacts of mining coal.*

Leximancer supports these findings with strong conceptual links evident between problem and CCS, government and policy in Figure below. Of lesser significance, but none the less important, are conceptual links between problem, efficiency, technology, development and emissions. Thematic overlaps exists across problem, society and New Zealand, and further between New Zealand, CCS and coal; which may be representative of societal concern regarding emissions and CCS.

Figure 4.9 Leximancer map - problem



What about the alternatives?

Many interviewees questioned how CCS would fit within the spectrum of solutions to climate change and sought information as to whether alternatives, such as renewable energy technologies, would be considered in any decision regarding the viability of implementing CCS in New Zealand.

> *When I look at the other available energy sources including especially other low cost, low or zero carbon technologies that we have available and the resources that we have available, my sense is that we will be able to do them at a lower cost more effectively than carbon capture and storage.*

Understanding the range of alternatives and where CCS fits is a common concern that has arisen across every country when discussing CCS as a mitigation option. This issue is particularly important for environmental NGOs that tend to be less supportive of extending the fossil fuel industry which is what CCS is often associated with. Feedback from an Australian workshop convened to assist in determining current NGO positioning on CCS highlighted a common stance held by attendees: that CCS must be seen as a transition technology only, and should not be implemented at the expense of government investment in renewable energy and energy efficiency measures (Ashworth & Parsons, 2009). It is considered that for any successful deployment of CCS to occur in Australia, due consideration to what the portfolio of energy options will be critical. It is anticipated that similar consideration to this issue would be critical in New Zealand.

> *And there is a very large sector of society that believes that anything that perpetuates the continued use of fossil fuels, which means whether you're capturing it or not, continuing to remit carbon dioxide and its variants, is wrong; that we should be moving to a much more sustainable model of energy production which involves a much greater reliance on renewables and clean technologies and such things as hydrogen.*

Related to this concept, the data also indicated that stakeholders raised questions about the capacity of CCS to achieve effective energy outcomes.

> *From an energy perspective I wonder about the net overall efficiency of the process. By the time they've combusted gas and then stuck it back in the hole in the ground again, how much energy is the net energy you get out of that process?*

Identifying a local benefit

For CCS to be truly viable, it was felt that identifying the local benefit that CCS will bring to a community will need to be clearly articulated. This was recognised as being crucial from any project's inception if CCS is truly to be considered a viable option. The issue of local benefit, or failure to articulate a clear local benefit, has arisen in many of the earlier attempts to deploy CCS projects around the world and has often resulted in a negative outcome where projects have been delayed or halted (Ashworth, 2010; Desbarats et al., 2010).

4.4.4 Perceived opportunities for CCS

The next set of questions (3, 4 & 5) in the interview process was designed to explore perceptions and views in relation to CCS and its future development in New Zealand. Analysis showed two major opportunities when considering CCS as an option within the New Zealand context. These included the idea that CCS has the potential to enable economic growth and can be a source of low emissions energy in New Zealand's future.

An 'enabler' of future economic growth in New Zealand

When asked their views on the potential for CCS in New Zealand, a key perception was that CCS had potential for facilitating economic growth in New Zealand in a 'carbon constrained' future. CCS was seen as a "great enabler" and a "fantastic opportunity for New Zealand" This theme was observed in all stakeholder groups, but was most apparent in those associated with industry. New Zealand was described as an energy rich country with CCS providing great potential to allow these resources to be used.

> *In terms of if there are opportunities, if they are productive opportunities out of all this that could be a catalyst for New Zealand to try and expand what we produce, expand our jobs market. The two could go hand in hand.*
>
> *CCS is more of an opportunity rather than something that's hugely required at this point in time from that perspective. Obviously, it allows us to utilise our resources in a lot more environmentally friendly way, well from a greenhouse gas emission mitigation perspective of carbon waste.*

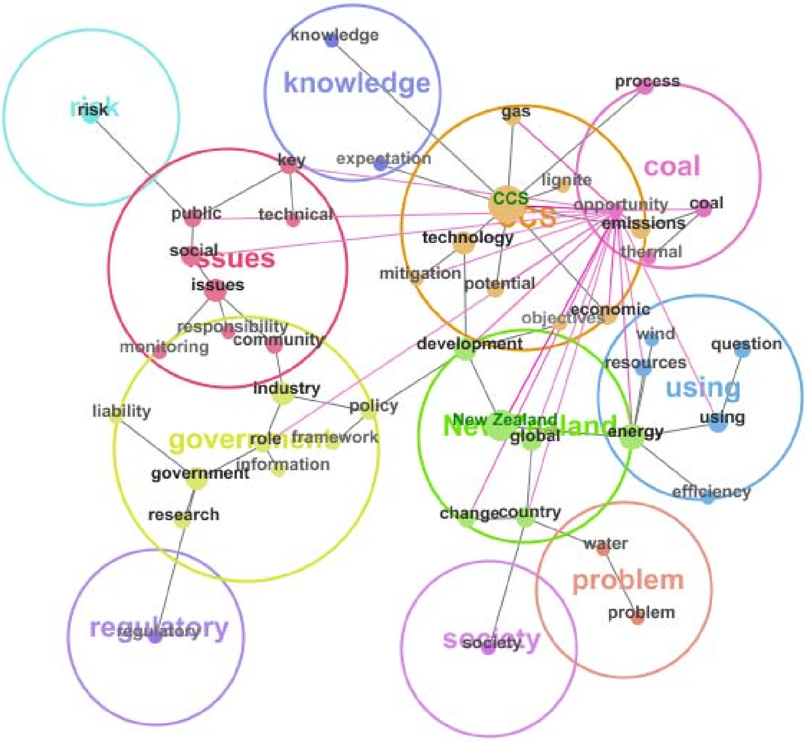
This was particularly evidenced in relation to any lignite (brown coal) to liquid program that might evolve. According to stakeholders several of these already exist within New Zealand.

> *I do see that there is a future for CCS in New Zealand on the back of coal to liquids, potentially if the South Island lignites get developed. And so in that respect the coal to liquids project could well have a generation aspect associated with it, and if it does, then there would be some opportunity for CCS related to electricity generation.*
>
> *Primarily CCS would be in existence for the monetisation of the lignites into terms of converting them to liquid fuels.*

Conceptually, opportunity links are limited as can be seen in the Leximancer map below (see Figure); however, the majority of what links do exist are quite strong. In particular links between opportunity and

CSS, role, New Zealand, change and economic. Thematically, the concept opportunity sat within the overlap between CCS and coal, which may be seen to support a perception that there is substantial opportunity to be gained through CCS within the coal industry.

Figure 4.10 Leximancer map – opportunity



A source of low emissions energy

Another theme in stakeholders' perceptions of CCS was that it had benefits as a source for low emissions energy generation and as part of the solution to addressing climate change. This theme was less apparent than the perception of CCS as an enabler of economic growth, but was nonetheless evident in responses by community and NGO stakeholders. Specifically, stakeholders noted that any low emission benefit from CCS would be tempered by New Zealand's existing relatively low global carbon emission contribution, the nation's already high use of renewable energy technologies, and a relatively high source of New Zealand's carbon emissions being from its agricultural sector, and not from energy generation alone.

> *.. the less carbon in the air, the less climate change, but is this enough? I don't think the benefit will be that big, because there are many other natural and agriculture greenhouse gases that need to be treated as well.*
>
> *It basically allows us to use our energy resources in a carbon constrained world, so we get particular benefit there. It allows us to diversify energy levels.*

4.4.5 Views on the future of CCS in New Zealand

Overall most stakeholders recognised the need for ongoing collaboration across government, industry and the research communities for CCS to progress.

> *I think there probably needs to be you know a three way dialogue across Government, industry and research about what it would take to make CCS viable in New Zealand.*

Role of government

Government was particularly seen as important for providing a policy enabling environment. One specific theme to emerge was a clearly perceived role for government to provide support to industry to develop CCS technology and to build a regulatory framework that ensures the 'certainty' required for its development. However, there was a clear expectation that government should not favour CCS but explore the whole portfolio of possibilities.

> *… the government needs to set the policy framework that is enduring, and primarily it will have to address the responsibility for the long-term liability of the carbon dioxide in the ground, because industry won't accept something that's sequestered effectively in perpetuity.*
>
> *Well, the role of government should obviously be regulations and ensuring that there are claims that are made about a site's liability and ensuring that more and ensuring that enforcement action is taken if practices are not as expected. So they should be part and parcel of the permitting and approval phase, and also take a reactive and proactive role in regulation and monitoring*

Some stakeholders openly expressed a desire for government not to pick winners in the mitigation space, particularly if doing so influences green policy. Their preference was to see market forces find the best way forward.

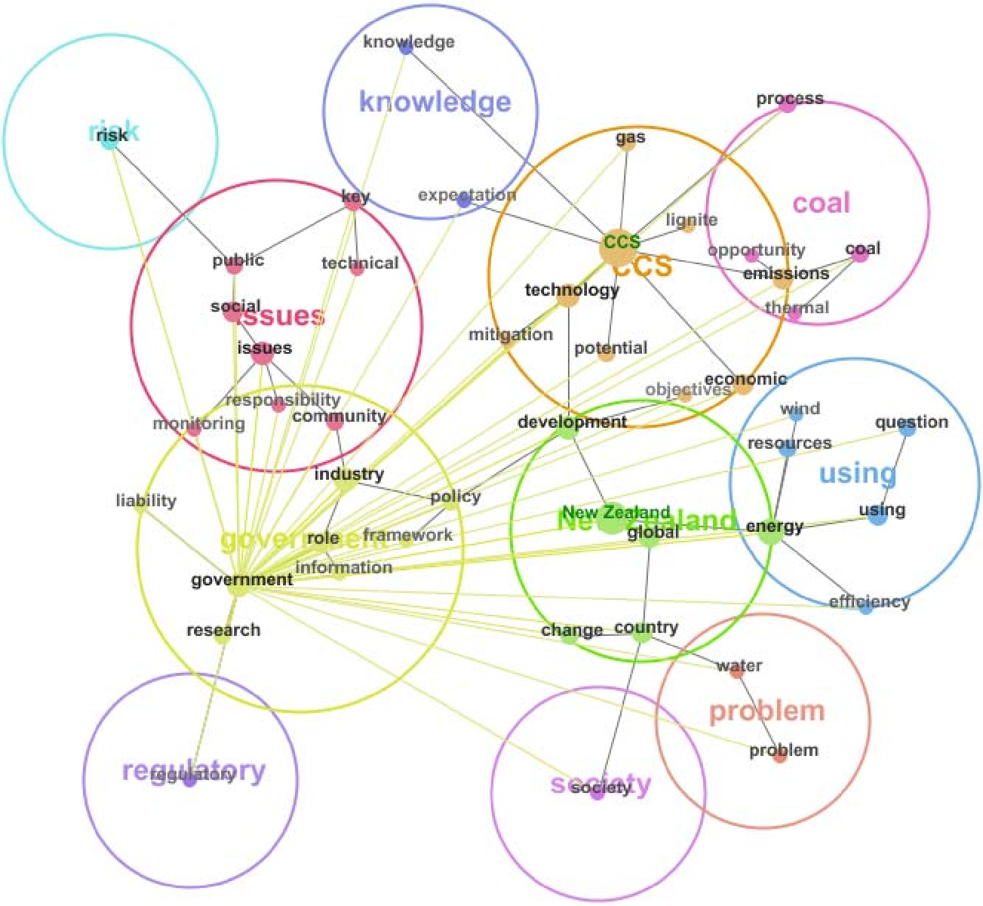
> *I like to focus my attention on is efficient resource use available that at the time is economic. I mean a lot of people talk about clean energy but they forget that it comes at a price and the market, in my opinion, always will go to the next paradigm in efficiency if it's allowed to work and so I've got a real negative feeling for governments influencing green policies.*

However, some stakeholders felt that the government should promote energy efficiency over carbon capture and storage.

> *But to be very honest, I do not believe that this is the, that this should be the priority of New Zealand government, because in fact it covers some real cost and it will not stimulate people who really do, to reduce their energy use in many, many ways. It is just a kind of excuse, you know.*

Thematically, government is linked across issues and regulatory. From a conceptual perspective government has multiple concepts closely located within the same theme including industry, research, role, responsibility, liability, policy, framework, monitoring and information. Additional to these concepts, government is linked closely to CCS, technology, development, global, and mitigation. These thematic and conceptual links visible in Figure 4.11 below would appear to be supportive of interviewee perspectives that government has a strong role to play in any future CCS may have within New Zealand.

Figure 4.11 Leximancer map – government



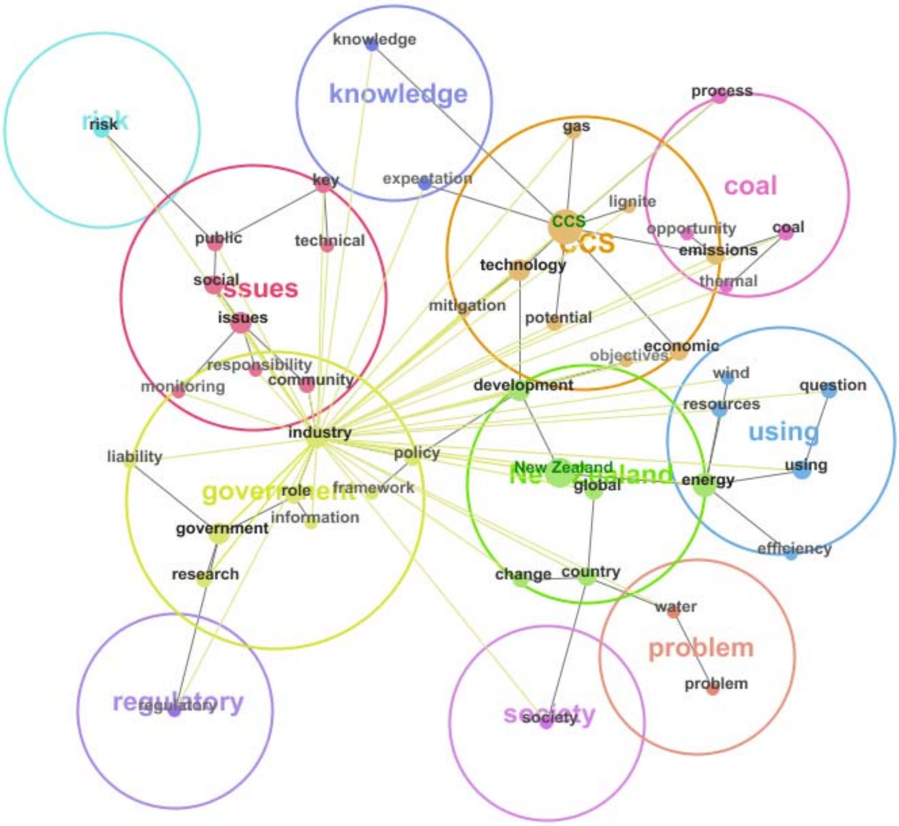
Role of industry

For CCS, industry's role was seen to be actively engaging in the development and deployment of technology that is scientifically supported and applied to tangible ventures that are deemed acceptable and actively contribute to New Zealand's mitigation goals. Industry was further seen to have a role to act responsibly within a sustainable framework to ensure minimal pollutants from their core businesses.

> *I'd rather see New Zealand's involvement being sort of more a facilitation side with industry taking the lead in investment and research and an assessment of the commercial viability.*
>
> *I do expect industry to make sure it uses its input really wisely and obviously, the wiser they use them the less outputs in terms of pollution, pollutants they are going to have.*

Conceptually, industry sits within the government theme in the Leximancer map below (see Figure) and has very strong links with government, technology, development, research, role, risk, liability, policy and economic. This close clustering with research,and government, might further support interviewer perceptions that there must be strong interplay between these organisations in developing and implementing CCS as a mitigation option and economic resource for New Zealand.

Figure 4.12 Leximancer map – industry



Role of research

A major role for researchers was to ensure adequate research was conducted into the safety of storage processes. In doing so it was also recognised that researchers should maintain the integrity of their research and not be influenced by industry funding. Similarly they were seen to have a role in assisting with information sharing.

> *And in terms of research bodies, well, being paid for by industry, research bodies should be ensuring that sites are adequate for their purposes, that there's no chance of migration, and that storage will be long-term.*
>
> *I would see them playing a really important role in information sharing because they're a good network for research around the world. That would be good for them to help to be a conduit of that information.*
>
> *But obviously there would have to be a lot of community engagement, consultation, forums, that type of thing. I mean there would have to be a lot of that happening if CCS was to occur in New Zealand.*

Objectives and expectations

> *When asked what objectives they thought CCS should achieve in New Zealand, responses varied. One objective expressed by some stakeholders was to allow New Zealand to develop its resources in a carbon-constrained world. Another participant expressed a hope that CCS would help diversify New Zealand's economy.*

> *New Zealand is desperate for some new manufacturing, new production activities for both employment and to try and ease their reliance on the agricultural sector, farming sector.*

Another objective expressed by stakeholders was that CCS should make a lasting contribution to mitigating New Zealand's greenhouse gas emissions. However, it was also stipulated that CCS should be seen as part of a portfolio of possibilities, and renewable and other more immediately available alternatives should be given priority.

> *Don't wait around and hope that this technology is developed, we've got to do things now to generate electricity in a way that doesn't create greenhouse gas emissions.*

Industry stakeholders also wanted certainty in terms of the predictions for the storage capacities of sites, and an enduring policy framework to address the long-term liability of CO_2 in the ground.

4.4.6 Potential Social and Cultural Issues

Local Opposition

Participants' ideas of the potential social and cultural issues that may arise in relation to CCS included opposition from environmental groups and local governments regarding liability and environmental impacts and damage to New Zealand's image as a 'clean, green' country and associated impacts on tourism.

> *I think the environmental community would raise a lot of concerns around non-permanence, land use impacts, and other environmental impacts.*

Regional Differences

Regional differences were also cited as a potential social issue for CCS deployment. It was felt that across New Zealand, local regions' different experiences with various industries and the interests of their locals would impact on their ability to accept CCS into their local region.

> *But it's actually at the local … you know, and there will be some parts of New Zealand that are used to having … like the Taranaki area; they are used to … it's a petroleum industry in New Zealand. So that is a region that is more coveted to that type of activity, whereas another example would be the Coromandel Peninsula, where, a lot of people have settled there because they love that environment and they want to protect that environment.*

However the interviews conducted to date have not demonstrated that any regional differences currently exist in relation to CCS. However, this may be explored in more detail through a larger sample size perhaps with a survey.

Need for Information

Educating and providing information to the community was seen as a key issue. Public acceptance of CCS and managing perceptions of risk was also seen as a key issue and it was felt that education would be a helpful way to overcome these issues.

> *I'd say culturally and socially, people would actually want to know how it would contribute economically. You know, why would people want to do CCS?*
>
> *The key social issues to address in terms of getting public accepting CCS, is primarily convincing them that it is safe, while not being kind of risk free, but it's safe and comparable to all the other types of risks that we take in accepted life.*

Indigenous Requirements

An area participants envisaged as being an emerging social issue was the potential for conflict between CCS and indigenous values and definitions of the landscape.

> *These are spiritual, so you know, they would be very concerned about any effects on natural resources, and especially natural resources that have strong connections to their ancestors; those types of things. Or sites if they … there's a word that is used, and it's used in the Resource Management Act, but it's wahi tapu, it's sacred sites …*
>
> *In terms of Maori spiritual and cultural values ... you know, they would be very concerned about any effects on natural resources, and especially natural resources that have strong connections to their ancestors*

However, there were varying views on this issue with some feeling that perhaps it would not pose too much of a problem and may actually be viewed as a positive opportunity for Maori.

> *I don't think there'd be a problem with it…. look at the Maori approach to waste water disposal for example… the preferred option that Maori people go for is just discharge to land so that the earth has a role to play as being a kind of a cleansing medium through which waste water passes and so it's purified in that way….*

Current Engagement Practices

Overall, the results indicate that stakeholders perceived existing community engagement frameworks in New Zealand as inadequate to deal with the community issues associated with CCS development. The importance of engaging early and the distrust of government adequately incorporating the views of stakeholders in their processes for CCS were expressed by some stakeholders.

> *I think the standard practice in Government, both this Government and the previous Government, has been to advance its own agenda and then put a document up for consultation rather than involving groups from the outset. So I think that sets the stage for distrust and opposition when unfairly advanced proposals are put forward.*
>
> *New Zealand promoters of this sort of stuff are inclined to be a little secretive for some time and then when they release it, it's still not good enough for those interest groups that have a lot of sway.*

Early community engagement was something that was not seen as a norm.

> *New Zealand tends not to anticipate social upheaval. We tend to react when it happens. If the social consequences of some of this stuff [is going to be] considered very, very far away from its happening stage, I would suggest it's probably unique. I don't know that it's happened before.*

Overall, participants were supportive of an early, integrated approach to community engagement involving all parties:

> *… to do it well you need to have a coordinated approach and having different parts of that chain, government, industry and research, providing different types of information [and] talking a different tune, only makes it harder. [You] need to really come up with the strategy rather than just saying "right, we're going to do it and off you all go people and do your bit".*
>
> *Non-government organisations, who just like to put the fear factor through society that everything that has gone before is really bad and what happens next is going to worse.*

4.5 Conclusions and Recommendations

4.5.1 Potential Social Issues for CCS in New Zealand

From the analyses the research indicates that there may be a number of potential social and perception issues which will need to be addressed if New Zealand is to successfully incorporate CCS into their portfolio of mitigation options.

Similar to other countries, the research clearly demonstrates that the public's lack of knowledge and understanding of what CCS is, what it is used for and its associated costs and benefits provides a real risk to successful deployment. Examples from previous failed technology transfer processes show that lack of knowledge can lead to misunderstandings and unrealistic expectations as to what the technology will achieve. If opportunities for CCS are to be realised in New Zealand this will have to be addressed as a priority.

Coupled with the above, are questions in relation to both the feasibility and viability of CCS in the New Zealand context. As CCS is deployed internationally there will be an opportunity for the lessons learned to be shared across New Zealand which should go some way to addressing the feasibility issues, particularly in relation to it being unproven and the associated risks regarding seismicity and leakage from reservoirs. However work could be done to identify adequate storage opportunities.

At the same time, it will be important for government to ensure that the portfolio of energy options, including energy efficiency, is openly pursued. There appears to be distaste at any evidence of the government trying to pick winners or failing to address the issue of carbon mitigation. This will also be exacerbated by opposition to technologies associated with coal mining and burning, and a perception that it doesn't deal with the 'real' problem – reducing reliance on carbon emitting technologies and mitigating climate change. The financial imperative is also a challenge that can possibly only be achieved with collaborating on the international scene.

Finally, there was some distrust in current government and industry engagement activities – leading to scepticism that stakeholder values and interests are incorporated into decision-making. This will be a critical issue to be addressed if there is any possibility of CCS moving forward in New Zealand. If it becomes part of the strategic direction for CCS – early engagement and dialogic approaches need to ensure stakeholder views are incorporated into the development of the technology.

4.5.2 Recommendations

If CCS is to be considered within the New Zealand context there are a number of actions that will need to be taken to ensure its successful deployment. These are listed below in no order of priority.

1. **Early and transparent engagement with a range of stakeholders**: This should focus on information stakeholders around the scope and potential for CCS.
2. **Prioritising stakeholders to engage**: With a new and emerging technology there are key stakeholders that are more influential and need to be prioritised over others. Examples include: politicians, media, financial investors, and non government organisations. Experience suggests it is important to ensure adequate resources including time are made available to engage these critical stakeholders.
3. **Address potential conflicts with stakeholders**: Like any emerging technology with associated risks some stakeholders will have opposing views about the risks and benefits it poses. Proactively

engaging stakeholders early in the process will help to identify the issues that need to be addressed.

4. **Evaluation of public attitudes:** It is worth investigating current public understanding and perceptions to climate change, CCS and the range of energy technologies for climate mitigation.

4.6 References

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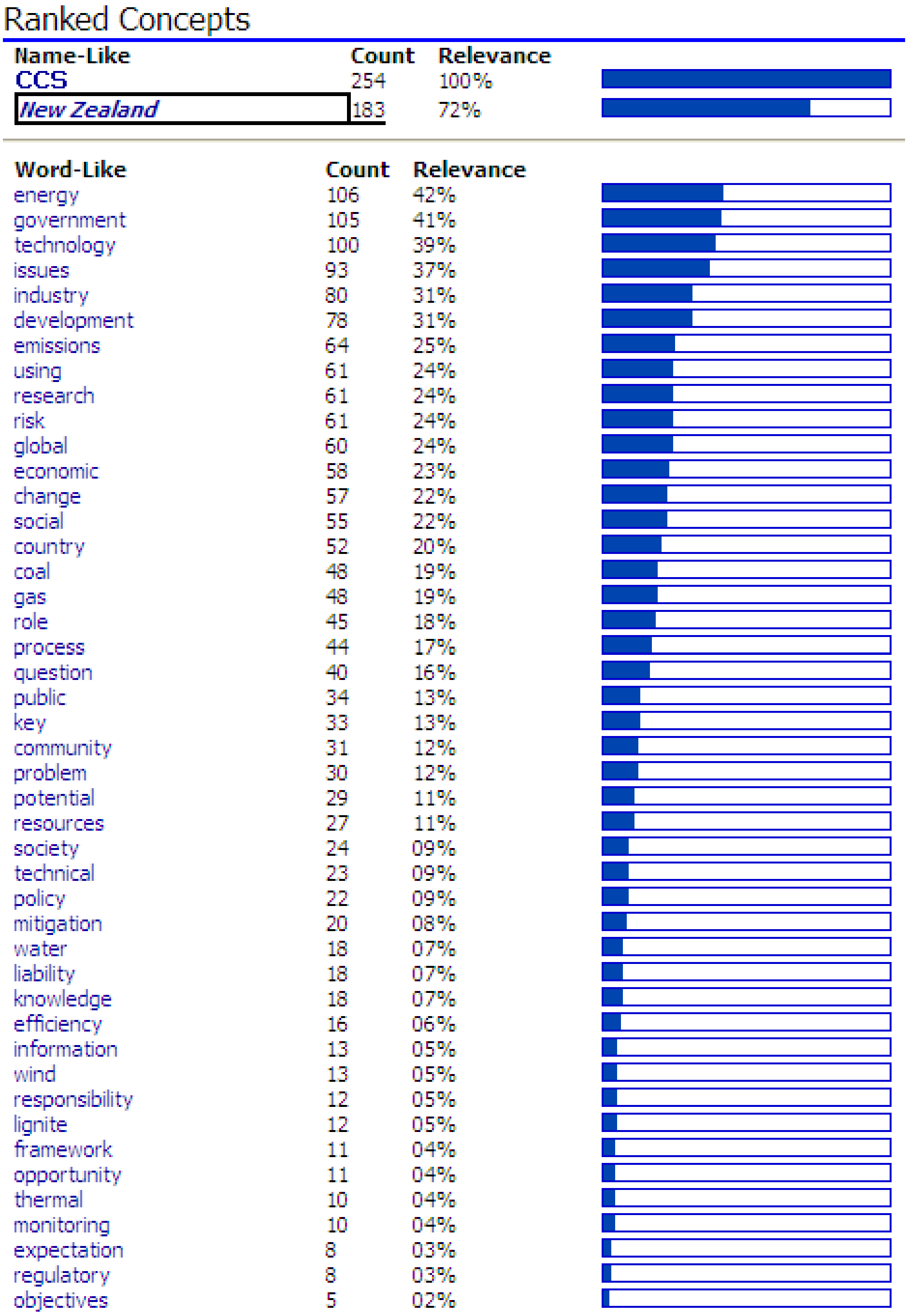
APPENDIX A



Ranked Concepts

Name-Like	Count	Relevance
CCS	254	100%
New Zealand	183	72%

Word-Like	Count	Relevance
energy	106	42%
government	105	41%
technology	100	39%
issues	93	37%
industry	80	31%
development	78	31%
emissions	64	25%
using	61	24%
research	61	24%
risk	61	24%
global	60	24%
economic	58	23%
change	57	22%
social	55	22%
country	52	20%
coal	48	19%
gas	48	19%
role	45	18%
process	44	17%
question	40	16%
public	34	13%
key	33	13%
community	31	12%
problem	30	12%
potential	29	11%
resources	27	11%
society	24	09%
technical	23	09%
policy	22	09%
mitigation	20	08%
water	18	07%
liability	18	07%
knowledge	18	07%
efficiency	16	06%
information	13	05%
wind	13	05%
responsibility	12	05%
lignite	12	05%
framework	11	04%
opportunity	11	04%
thermal	10	04%
monitoring	10	04%
expectation	8	03%
regulatory	8	03%
objectives	5	02%