

# Carbon Dioxide Capture and Storage

Report of  
DTI International  
Technology  
Service Mission  
to the USA and  
Canada from  
27<sup>th</sup> October to  
7<sup>th</sup> November  
2002



Department of Trade and Industry

Advanced Power Generation Technology Forum  
An Associate Programme of UK Foresight





Nick Otter  
Mission Leader

*The views and judgements expressed in this report reflect a consensus reached by the Members of the Mission team and do not necessarily reflect those of the organisation to which the Members of the Mission belong, the APGTF or the UK Department of Trade and Industry. Whilst every care has been taken in compiling the information in this report, none of the organisations referred to above can be held responsible for any errors or omissions.*

## Message from the Mission leader

I was delighted to be able to lead this DTI International Technology Service Mission on CO<sub>2</sub> Capture and Storage to the USA and Canada. It proved to be an excellent opportunity to gain a first hand understanding of what is likely to be a highly significant area of technology for the future.

From all the energy forecasts that we see, it is apparent that fossil fuels will be used for a considerable time to come, especially in some of the developing countries where there are significant indigenous supplies coupled with growing populations and a strong desire to improve their economic position and quality of life. The clean use of fossil fuels will therefore be essential if we are to seriously address the issues of climate change and it represents a major transitional challenge in our desire to get to a more sustainable energy future.

Our discussions in the USA and Canada indicated that both countries are adopting an integrated carbon management strategy that includes fossil fuels. Their approach is to address the shorter term, more immediate issues by achieving CO<sub>2</sub> mitigation through increased efficiency and, at the same time, developing technologies for zero (or at least near zero) emission power plant for the future. CO<sub>2</sub> capture and storage is therefore an increasingly important aspect of their longer term strategy and of their technology road maps. Both countries are active in setting up demonstration projects for CO<sub>2</sub> capture and taking a lead in the development of protocols for CO<sub>2</sub> storage and use. It is clear that both countries have acquired (and are continuing to do so) substantial experience across the whole field, including the important aspects associated with infrastructure and transport.

Although there are a different set of circumstances in the UK, I feel that we can learn substantially from the knowledge gained on the Mission. The first course of action is to ensure a proper dissemination of the findings. The timing of the Mission was such that on its return, we were able immediately to provide the major Mission findings to the DTI team writing the Energy White Paper for the UK. This report is the next stage of the dissemination process and builds on the very successful seminar held in London on 15th January 2003.

My final words are ones of thanks to all the hosting organisations in the US and Canada, they could not have been more helpful and welcoming; to the British Embassy, High Commission and Consulate staff who sorted out a lot of the local logistics and hosted the Mission receptions; to the DTI for financing the Mission and in particular Philip Sharman for his tireless support well beyond the call of duty; to Judy Henson at ALSTOM Power for all her help with the organisation and report; and finally to the Mission team itself who made the whole trip such a memorable and extremely enjoyable experience.

We all learned a lot – I hope that you find the report an interesting and worthwhile read.



Nick Otter

Chairman of the UK Advanced Power Generation Technology Forum  
and Director of Technology and External Affairs, ALSTOM Power Ltd

February 2003



## Executive summary

### The Context

The consensus view among the world's leading scientists is that climate change is occurring and that it is linked to increasing concentrations of greenhouse gases (GHGs) in the atmosphere enhancing the natural "greenhouse effect". Carbon dioxide (CO<sub>2</sub>) is the most significant of these GHGs, with atmospheric concentrations increasing steadily since the Industrial Revolution. The combustion of fossil fuels is the most significant source of man-made CO<sub>2</sub>.

In order to stabilise CO<sub>2</sub> concentrations or reduce them, global emissions of CO<sub>2</sub> would need to decrease dramatically. This is a tough challenge since fossil fuel use has underpinned, and continues to underpin, the economic growth of industrialised countries and, increasingly, developing countries. Overall, fossil fuels are likely to remain the major source of energy over the next 30 to 40 years. Given this, a portfolio of approaches is likely to be needed to drive CO<sub>2</sub> emissions down without impeding economic growth. This would include efficiency improvements (both in energy supply and use), reducing the carbon intensity in energy production (i.e. fuel switching, renewable energy technologies and possibly additional nuclear power) and the cleaner use of fossil fuels, including sequestration of CO<sub>2</sub>. This cleaner use of fossil fuels is seen by many as an important transition stage, paving the way for zero emission energy and, in time, the increasing use of hydrogen, rather than electricity, as the major energy vector.

### The Mission

In this context, and recognising the potential importance of CO<sub>2</sub> capture and storage, the UK Advanced Power Generation Forum (APGTF) – with support from the Department of Trade and Industry (DTI) International Technology Service – organised a Technology Mission to the two leading countries in this field (i.e. the USA and Canada) to establish an up-to-date understanding of the state-of-the-art of CO<sub>2</sub> capture and storage in geological structures.

Five leading UK companies, a prominent research institution and the DTI joined the Mission, visiting 15 private and public sector organisations in the USA and Canada over an 11 day period.

The Mission addressed primarily technology issues concerning CO<sub>2</sub> capture and storage, most notably those technologies where the CO<sub>2</sub> could be used to provide a revenue stream thereby providing an early and more cost effective route to large scale carbon sequestration, i.e. enhanced oil recovery (EOR) and enhanced coal bed methane (ECBM) production.

Other relevant aspects of CO<sub>2</sub> capture and geological storage were also addressed, including techno-economic, health and safety, risk, environmental, infrastructure, legal, public perception, fiscal and policy issues.

On returning to the UK, the APGTF organised a dissemination seminar in London at which the Mission team presented its findings to a group of over 100 interested participants.

### CO<sub>2</sub> Capture

A number of technologies for capturing CO<sub>2</sub> from large scale power and heat processes are currently being developed, demonstrated or deployed in the USA and Canada, broadly falling into three categories: post-combustion flue gas scrubbing; firing the combustion process with oxygen ("oxy-fuel" firing) rather than air to produce a flue gas made up primarily of CO<sub>2</sub>; and pre-combustion decarbonisation, in which the fossil fuel is generally gasified to produce a synthetic gas that is then decarbonised prior to combustion.

Of the post-combustion flue gas clean-up technologies, amine scrubbing is a leading candidate. However, these processes are very capital and operating cost intensive and little operating experience has been gained to date in treating flue gases. While costs are likely to decrease substantially as more plant is deployed, technical problems are likely to be encountered, pointing to the need for co-ordinated and collaborative R&D and demonstration. The Mission included discussions with a number of research and utility organisations actively pursuing this route to CO<sub>2</sub> capture.

Oxy-fuel firing (also referred to as O<sub>2</sub>/CO<sub>2</sub> recycle) is the subject of much interest, particularly in Canada, complementing work in the UK. A contender, alongside amine flue gas scrubbing, for retrofitting to existing power stations, oxy-fuel technology also requires further R&D and demonstration. A visit was made to a pilot oxy-fuel firing test facility in Canada, and discussions were had with a consortium considering a demonstration of a retrofitted oxy-fuel firing system to a coal-fired power plant.

The pre-combustion decarbonisation route to CO<sub>2</sub> capture is of particular interest in the longer term and for “greenfield” power plants. Integrated gasification combined cycle (IGCC) power plants have been the subject of several demonstration projects around the world (particularly in the USA), potentially offering high efficiency and excellent environmental performance. Such plant configurations can also be adapted to enable “sequestration ready” CO<sub>2</sub> to be produced at high pressure, with electricity – and/or hydrogen for clean fuel applications – as the primary product, pointing the way forward to a “hydrogen economy”. The Mission team visited a synfuels plant in North Dakota that is capturing CO<sub>2</sub> through a gasification process and selling it for an EOR operation in Saskatchewan.

### **CO<sub>2</sub> Transport in Pipelines**

Due mainly to its large scale and mature CO<sub>2</sub>-EOR business, the USA has the largest CO<sub>2</sub> pipeline network in the world, extending to approximately 3,000km and carrying several million tonnes of CO<sub>2</sub> annually. These pipelines, and similar lines in Canada, transport CO<sub>2</sub> as an ostensibly dry, dense phase, supercritical fluid. Over 30 years operational experience has allowed the pipeline operators to solve issues surrounding corrosion, pipeline safety, inspection, etc. While issues in the UK would be somewhat different (i.e. issues of building an infrastructure from scratch and most likely in a marine environment as well as on land), the US and Canadian experience and safety record was reassuring. Site visits were made to CO<sub>2</sub> pipelines and associated infrastructure in West Texas and North Dakota/Saskatchewan.

### **CO<sub>2</sub> Storage in Geological Structures**

Geological structures being considered for CO<sub>2</sub> storage include depleted/depleting oil and gas fields, deep unmineable coal seams and saline aquifers. Many issues need to be addressed before large scale sequestration is possible, such as the security of long term storage, the capacity of the most promising “sinks”, the verification of the storage, the risks associated with leakage, the costs, the legality and public acceptability. It is to address these issues that a number of R&D, pilot and demonstration activities have been initiated in North America.

### **CO<sub>2</sub> Use**

Additional hydrocarbon recovery, in conjunction with CO<sub>2</sub> sequestration, provides an early and potentially cost effective route to geological storage. The two leading contenders in this regard are CO<sub>2</sub>-EOR and ECBM production, although outside of North America, CO<sub>2</sub> injection for enhanced gas recovery (CO<sub>2</sub>-EGR) is also being considered.

Tertiary production of oil using CO<sub>2</sub> injection is an established technology with over 30 years experience existing in West Texas (the billionth barrel of incremental oil from this method was produced there during 2002). Significant amounts of incremental oil are recoverable, extending field life, maintaining employment and creating wealth. Long term commercial contracts between CO<sub>2</sub> suppliers and users have stimulated a market for CO<sub>2</sub>. No significant technical problems to deployment remain.

The Mission team visited two oil fields using CO<sub>2</sub> injection for EOR. At the SACROC field in West Texas, an incremental 200 million barrels of oil (13-15% of the original oil in place) is expected to be recovered through CO<sub>2</sub>-EOR, with the field's life being extended by more than 20 years. The Weyburn oil field in Saskatchewan is expected to yield an additional 130 million barrels (around 9% of the original oil in place) during its 25 year extended life. Both operations are economic, although this is only because of the fiscal regimes put in place by federal and state/provincial governments to encourage tertiary production of oil.

ECBM production (involving injected CO<sub>2</sub> sweeping trapped methane from deep and unmineable coal measures) is much less advanced in its development than EOR. The two trials that have been undertaken to date are both in North America, one in New Mexico, the other in Alberta. The Mission team met with the various organisations involved in the Alberta micro-pilot test, involving a programme of a single well test, a trial of injecting unprocessed flue gases and a future 5-well pilot project.

The technique/science is not fully understood and the issue of coal permeability is key (as it would be in the UK). However, the size of the potential "sink" for CO<sub>2</sub> is very large and justifies an active on-going international collaborative R&D activity.

### **Wider Related Issues**

The Mission examined many other technical and non-technical aspects of CO<sub>2</sub> capture and geological storage. These included health, safety and environmental issues associated with CO<sub>2</sub> storage in geological structures, public perception, legal issues, fiscal frameworks to encourage CO<sub>2</sub>-EOR or ECBM recovery and R&D requirements.

During the Mission, a number of opportunities were identified for possible UK collaboration or involvement with both the USA and Canada. These opportunities covered technology collaboration (ranging from information exchange to participation in demonstration projects) and collaboration on economic and policy-related issues. In all, some 12 new collaboration opportunities were identified. These will need to be carefully evaluated on their merits.

### **Key Messages from the Mission**

In both the USA and Canada, fossil fuels will continue to be an important part of the fuel mix, and their clean use is a key component in the transition to a sustainable energy future. Increased power plant efficiency and the capture and storage of CO<sub>2</sub> are being actively pursued alongside other energy technologies, providing a vital link to the prospect of a "hydrogen economy".

EOR using CO<sub>2</sub>, and the pipeline transport of CO<sub>2</sub> in large quantities over long distances necessary to support it, is an established technology in North America. Furthermore, large-scale capture of CO<sub>2</sub> is practiced under long-term contracts between CO<sub>2</sub> suppliers and users. This experience is relevant to the UK.

The current position in the North Sea is analogous to that in West Texas at the time of the 1970s' oil crises, when EOR was used to boost US oil production and strengthen the security of energy supply. Legislation provided the financial incentives to encourage the investment required for EOR projects.

The USA and Canada are adopting an integrated approach towards fossil fuels and have significant programmes covering CO<sub>2</sub> mitigation from increased efficiency right through to zero emission with CO<sub>2</sub> capture and sequestration. The development of clean coal technologies, and their demonstration with CO<sub>2</sub> capture, is seen as crucial, both technically and from an economic standpoint. Both countries are seeking to establish internationally funded, commercial sized demonstration plants based in North America.

Canada is looking to introduce "carbon saving" measures that encourage the take up of new technologies using fossil fuels, alongside emissions trading and other policies. A balance must be struck between environmental performance, security of supply and industrial competitiveness. It is recognised that increased deregulation, privatisation and liberalisation do not encourage investment in new technologies; to address this, the Government is considering setting up a "partnership fund" for the demonstration of clean coal technologies linked to CO<sub>2</sub> capture and storage. This proactive role will clearly secure benefits to Canada. The USA has adopted a similar stance, supported by programmes under its Clean Coal Power Initiative (CCPI), Vision 21 and Carbon Sequestration Program.

Considerably increased research activity in universities and other research institutions is catalysing further technological development and scientific understanding to underpin the R&D and demonstration activity. A high degree of co-ordination and integration was observed between industry, government and academia, with evidence already of robust partnerships and networks as both countries seek international co-operation at all levels.

The need to develop protocols for CO<sub>2</sub> storage is well understood, especially in Canada, which is taking the lead on this and other issues, building upon its prominent role in international activity such as the IEA Greenhouse Gas R&D Programme.

There is evidence in North America of active public awareness schemes resulting in informed public debate and an increased understanding of individual responsibility.

### Recommendations

- The UK should develop a long term, integrated carbon management strategy encompassing a portfolio approach, including fossil fuels, as well as other energy technologies. The clean use of fossil fuels should cover CO<sub>2</sub> mitigation from increased efficiency (in both generation and use) right through to (near) zero emission power plant with CO<sub>2</sub> capture and storage: This will be critical in the transition to a sustainable energy future. In this context, it is recommended that cost reduction of capture technologies should be addressed and that storage options in the North Sea be identified and optimised.
- Enhanced oil recovery with CO<sub>2</sub> injection should be used to extend the life of the North Sea oil reserves, yield significant incremental oil production (thereby improving the UK's security of energy supply) and stimulating a market for CO<sub>2</sub>. Financial incentives would be required for this to happen; these must have sufficient duration to encourage investment in the infrastructure required in the North Sea. A window of opportunity exists in the next ten years, after which it will be difficult to take any such initiative forward.
- In order to position the UK to take advantage of the opportunities in carbon management, an implementation plan should be developed on an urgent basis. This should involve the oil and gas, power generation and other industrial sectors, together with Government and, where appropriate, the research base. Such a plan would enable the potential for an UK-based, internationally funded demonstration project (complementing those found elsewhere) to be identified.
- The strong lead taken by Canada in the development of a protocol for CO<sub>2</sub> storage should be supported, so that the interests of the UK in offshore, sub-sea storage are properly represented at the international level.
- The UK should take an active part in appropriate international activities currently underway, both at a research and industrial level.
- Greater co-ordination should be established between the different governmental and private funding bodies, the different parts of industry, the different parts of the research community and, importantly, between them all. The development of "technology and commercialisation roadmaps", backed by deployment studies, would considerably help this process.
- Increased public awareness and acceptance of the issues should be developed.

### Acknowledgements

Many organisations and individuals contributed to the success of this Technology Mission. The Mission organisers and participants wish to extend particular thanks to:

The Department of Trade and Industry's International Technology Service

The British Embassy in Washington, the Consulate-General in Houston, the British High Commission in Ottawa and the British Trade Office in Calgary

The Canadian CO<sub>2</sub> Capture and Storage Technology Network

The 19 US and Canadian companies and government organisations that hosted the Mission team.

# Contents

	page
Message from the Mission Leader	i
Executive Summary	iii
Acknowledgements	vi
Contents	vii
1 <b>Introduction</b>	1
2 <b>Aims and Objectives of the Mission</b>	3
3 <b>Overview of the Mission</b>	5
3.1    Participants	
3.2    Visits	
3.3    Technology Areas and Other Issues	
3.4    Questions Addressed	
3.5    Dissemination Seminar in London	
4 <b>Policy Issues and Initiatives in the USA and Canada</b>	9
4.1    Introduction	
4.2    USA - Perspectives, Policy and Programmes	
4.3    Canada - Perspectives, Policy and Programmes	
4.4    Other Activities Ongoing in North America	
4.5    Comparison with UK Policy on CO <sub>2</sub> Capture and Storage	
5 <b>Carbon Dioxide Capture</b>	21
5.1    Post-Combustion Capture (Flue Gas Scrubbing Routes)	
5.2    Oxy-fuel Firing (O <sub>2</sub> /CO <sub>2</sub> Recycle Routes)	
5.3    Pre-Combustion Capture/Decarbonsiation (Hydrogen and Syngas Routes)	
6 <b>Carbon Dioxide Transport in Pipelines</b>	45
6.1    Background	
6.2    Operational and Practical Issues	
6.3    Implications and Lessons for the UK	
7 <b>Geological Storage</b>	53
7.1    Background to the Technology	
7.2    Operational and Practical Issues	
7.3    Implication and Lessons for the UK	
8 <b>Carbon Dioxide Use</b>	57
8.1    CO <sub>2</sub> Use for Enhanced Oil Recovery	
8.2    CO <sub>2</sub> Use for Enhanced Coal Bed Methane Recovery	
9 <b>Social, Legal and Research Issues</b>	75
9.1    Health, Safety and Environment	
9.2    Public Perception	
9.3    Legal Issues	
9.4    Fiscal Regimes to Encourage EOR and ECBM	
9.5    Research Positioning and Co-operation	
9.6    Implications and Lessons for the UK	
10 <b>Major Outcomes of the Mission</b>	83
10.1   Key Messages	
10.2   Opportunities Identified for the UK	
10.3   Recommendations from the Mission	
<b>Appendices</b>	87
Appendix A:    Mission Participants Contact Details	87
Appendix B:    Mission Hosting Organisations Contact Details	88
Appendix C:    Mission Questions	90
Appendix D:    Dissemination Seminar Summary	92
Annex to Appendix D: Seminar Programme	96



# 1 Introduction

There is a consensus view emerging in the scientific community world-wide that there is a strong link between human activity and climate. This is exemplified by the latest report of the Intergovernmental Panel on Climate Change (IPCC)<sup>1</sup>. As such, climate change is becoming a matter of genuine public concern. Although the relationship between man and our climate is uncertain, and the science not fully understood, it seems clear that climate change is linked to increased concentrations of greenhouse gases (GHGs) in the atmosphere coming from human activity (termed the “enhanced greenhouse effect”). Of the GHGs, carbon dioxide (CO<sub>2</sub>) is the most significant and atmospheric concentrations of man-made (“anthropogenic”) CO<sub>2</sub> have been rising steadily since the Industrial Revolution, particularly from the middle of the 20th Century. These concentrations now stand at about 375ppm by volume compared with a stable, pre-industrial level of around 280ppm, maintained for at least the last 6,000 years. Such a rate of increase and levels of CO<sub>2</sub> have not occurred in the natural system for at least 20 million years; hence, a precautionary approach has been called for by some to restrict future GHG emissions. The Royal Commission on Environmental Pollution (RCEP) recommends<sup>2</sup> that in order to hold the atmosphere at current CO<sub>2</sub> concentrations, global emissions would need to fall by over 60% before 2050. In addition to contributing to climate change, other possible impacts of increased atmospheric concentrations of CO<sub>2</sub> are causing concern, such as ocean acidification and the serious consequences for marine organisms.

The main cause of the increase in atmospheric CO<sub>2</sub> has been the combustion of fossil fuels for power generation, industrial use and transportation. This use has underpinned the development of industrialised countries where demand for energy is still increasing at approximately 1.7% per year<sup>3</sup>. World electricity demand is expected to grow at about 2.4% per year out to 2030<sup>3</sup>, mostly in developing countries where demand growth is expected to be around 4% annually<sup>3</sup>. Much of this demand will be met by the use of fossil fuel, especially coal and gas. This will set a severe environmental challenge as the energy supply and end-use sectors account for approximately 85% of man-made GHGs. Engagement of developing countries in the process of environmental improvement will be essential.

In order to tackle the climate change issue, a wide range of measures will be required; there is no single winning technology, rather a portfolio of approaches is called for, the emphasis of which will change with time. Such an approach will embrace improved and reduced energy use on the demand side plus, on the supply side, higher efficiency of electricity generation, the greater use of low carbon fuels (e.g. hydrogen derived by decarbonising fossil fuels), cleaner use of traditional fossil fuels, expanded renewable energy and probably new nuclear.

The clean use of fossil fuels in power generation and industrial applications (such as in the production of cement, chemicals and steel) is increasingly accepted as a major transitional issue in moving towards a sustainable future and is therefore a critical matter for policy-makers. This arises not only from an environmental perspective and the need to meet Kyoto and future targets, but also from a security of supply perspective, where it is clear that coal and gas will remain key fuels well into the 21st Century. Any strategy for the future needs to embrace CO<sub>2</sub> mitigation through increased efficiency, thereby reducing the amount of CO<sub>2</sub> produced per unit of useful energy, and also to set a “road map” towards zero emission power plant. For fossil fuels, this will mean ultimately capturing and storing CO<sub>2</sub>. The potential importance of CO<sub>2</sub> capture and geological storage, and the need for more detailed investigation, has been emphasised in three key reports in recent months in the UK: the Cabinet Office’s Performance and Innovation Unit (PIU) Energy Review<sup>4</sup> (the report to Government that informed the Energy White Paper to be published in 2003), the Department of Trade and Industry (DTI) review of the case for Government support for cleaner coal technology demonstration plant of 2002<sup>5</sup> and the Chief Scientific Advisor’s review of UK R&D energy needs<sup>6</sup>, also published in 2002. In Europe, the theme of CO<sub>2</sub> capture and storage associated with clean fossil fuel power plant has been established as a priority within the forthcoming EC Framework RTD Programme (FP6) in Energy<sup>7</sup>.

<sup>1</sup> Third Assessment Report (TAR): “Climate Change 2001 : The Scientific Basis”, IPCC, 2001

<sup>2</sup> RCEP Report 22, “Energy - the Change in Climate”, June 2000

<sup>3</sup> “World Energy Outlook : 2002”, OECD/IEA, 2002

<sup>4</sup> Energy Review, PIU Cabinet Office, February 2002

<sup>5</sup> Review of Case for Government Support for CCT Demonstration Plant, DTI, December 2001

<sup>6</sup> Chief Scientific Advisory Energy Research Review, Recommendations to PIU, Office of Science and Technology, February 2002

<sup>7</sup> European Commission Framework 6 on RTD, Work Programme ‘Sustainable Energy Systems, Dec 2002

In 2002, the UK Advanced Power Generation Technology Forum (APGTF), an Associate Programme of the UK Foresight Energy and Natural Environment Initiative, produced a report<sup>8</sup> that set the strategy for fossil fuel power plant technologies for the UK. Again, this identified CO<sub>2</sub> capture and storage as a potential critical technology for the 21st Century and became a major input into the zero emission power generation study and report by Foresight<sup>9</sup>. This emphasised the need to take a broad-based approach, with fossil fuel technologies being assessed alongside those of nuclear and renewable energy sources. It identified that one of the early routes for the implementation of CO<sub>2</sub> capture and geological storage could be through the application of enhanced oil recovery (EOR) techniques, implying use in the North Sea in the case of the UK.

As a result, it was accepted that the UK industry and research community needed to establish an up-to-date understanding of the state-of-the-art CO<sub>2</sub> capture and geological storage technologies and world-wide activities. Canada and the USA were identified as countries of specific interest. The APGTF, with the support of LOGIC (the organisation working with PILOT, an important grouping of Government, industry and suppliers in the oil and gas sector), was therefore granted support from the DTI International Technology Service Missions Programme to visit Canada and the USA and to report back to UK stakeholders and interested parties. The Mission took place in October and November 2002.

This document summarises the Mission, the places that were visited, the technologies considered, the outcomes of the discussions and the opportunities and benefits that could accrue to the UK. It is emphasised that the Mission not only addressed CO<sub>2</sub> capture and geological storage technologies, but also those of CO<sub>2</sub> transport and use. In addition, it is important to note that the issues associated with legal, infrastructural, social, environmental, economic, health and safety, policy, fiscal and public perception matters were also considered. Other (i.e. non-geological) storage options, namely storage in oceans or terrestrial ecosystems, were not considered during this Mission.

The report has been written to complement a dissemination seminar hosted by the DTI on 15 January 2003 and is available on the APGTF website at [www.apgtf-uk.com](http://www.apgtf-uk.com)

<sup>8</sup> Transition to Zero Emission Carbon Emission, UK Advanced Power Generation Task Force, July 2001

<sup>9</sup> Power without Pollution, ZEPG Report, UK Energy and National environment Panel, Foresight February 2002

## 2 Aims and objectives of the Mission

The Mission aimed to provide UK industry (especially the electricity generators, the oil and gas producers and the engineering companies that supply and manufacture power systems and components) with information on the technology options available for CO<sub>2</sub> capture and geological storage. There was a particular emphasis on geological storage associated with enhanced oil recovery (EOR) and enhanced coal bed methane (ECBM) production.

In this context, the aims of the Mission were:

- To improve UK awareness of current practices and developments in the USA and Canada.
- To develop opportunities for collaboration and technology transfer to help develop CO<sub>2</sub> capture and geological storage activity and competence in the UK.
- To highlight opportunities for CO<sub>2</sub> capture and geological storage both on- and offshore in the UK.
- To gain a better understanding of the costs involved.
- To gather any relevant information on environmental/risk analyses that had been undertaken.

In addition to these aims, there were also the specific objectives of:

- Facilitating new relationships of potential value to UK industry.
- Supporting the development of a UK CO<sub>2</sub> capture and geological storage capability.
- Exposing UK organisations to leading-edge thinking and activity, thus supporting their own development.

*The Mission  
Team at  
Weyburn.*

*left to right:  
Philip Sharman  
Andy Timms  
David Hanstock  
Nick Otter  
Tony Howard  
Dave Craigen  
(EnCana host)  
Nick Riley  
Brian Morris  
Brian Ricketts*



*Route of CO<sub>2</sub> Mission to the USA and Canada - covering 20,000 miles*



*Lignite Fired Power Stations in North Dakota, USA*



*Boundary Dam Power Station, Saskatchewan, Canada*



## 3 Overview of the Mission

The Mission was supported by the UK Department of Trade and Industry (DTI) International Technology Service (ITS). ITS backs short fact-finding visits overseas by small groups of technical experts from UK companies, to identify and learn from the best practice and technological developments in leading companies overseas. ITS funds the travel costs and helps towards the sponsoring body's costs of organisation and promotion. Full details of DTI missions and other activities of the ITS can be found at [www.globalwatchonline.com](http://www.globalwatchonline.com)

### 3.1 Participants

The Mission was organised by the **Advanced Power Generation Technology Forum** (APGTF) and led by Mr Nick Otter, APGTF Chairman. Nick Otter is the Director of Technology and External Affairs for ALSTOM Power and, consequently, also represented the interests of ALSTOM on this Mission.

The APGTF, formerly the Advanced Power Generation Task Force, is an industry-led "Associated Programme" of the UK Foresight Energy and Natural Environment Initiative and was established to identify and promote RD&D strategy targets and priorities for the UK, both for economic benefit and improvement of the environment. The scope of the Forum now covers advanced power generation from fossil fuels and biomass and CO<sub>2</sub> capture, transportation and sequestration. It is made up of representatives of the trade associations involved in the power generation sector, UK Government and academia.

The APGTF has been active in developing a UK RD&D strategy for fossil fuels and promoting this through three annual UK Forum meetings. The APGTF's strategy document<sup>8</sup> has been a significant input into the DTI's Office of Science and Technology Foresight Programme and, furthermore, has led to the establishment of a Zero Emission Power Generation (ZEPG) Group under Foresight. A report pointing the way forward was published by the ZEPG Group in 2002<sup>9</sup>. In addition, the APGTF has played a major role in a DTI-sponsored meeting with the US Department of Energy (under a 10 year Memorandum of Understanding between the US Department of Energy and the DTI) to identify common areas of interest for fossil fuel RD&D. This has led to three or four areas of interest being discussed and an ongoing series of workshops and missions being developed, as well as a DTI-funded project. Further information about the APGTF can be found on its website [www.apgtf-uk.com](http://www.apgtf-uk.com)

Five UK companies (**Powergen UK plc, Progressive Energy Ltd, Mitsui Babcock Ltd, ALSTOM Power and UK Coal Ltd**) were represented on the Mission, covering a broad range of technical interests in CO<sub>2</sub> capture and storage. A leading academic in the field of geological storage from the **British Geological Survey** joined the Mission team to represent the UK academic community and address scientific issues.

The APGTF has extensive contacts with organisations that are currently concerned with CO<sub>2</sub> capture issues and opportunities in the UK. Furthermore, the Mission team included the DTI's International Technology Promoter for sustainable energy and environmental technologies for North America and the Manager of the DTI's Cleaner Fossil Fuel Unit.

*The Mission team members and their respective affiliations are summarised in this table*

*Full particulars and contact details for the Mission participants are included in Appendix A*

Mission Team	
<b>Sponsor and Supporting Organisations</b>	
Advanced Power Generation Technology Forum (APGTF)	Mr Nick Otter
DTI International Technology Promoter	Mr Philip Sharman
DTI Cleaner Fossil Fuels Unit	Mr Brian Morris
<b>Industrial Participants</b>	
Powergen UK plc	Dr Tony Howard
Progressive Energy Ltd	Dr David Hanstock
Mitsui Babcock Ltd	Mr Andy Timms
ALSTOM Power	Mr Nick Otter
UK Coal Ltd / Confederation of UK Coal Producers / World Coal Institute	Mr Brian Ricketts
<b>Academic</b>	
British Geological Survey	Dr Nick Riley

### 3.2 Visits

The Mission took place between 28 October and 7 November 2002. During that period, the group met with over 19 private and public sector bodies in the USA and Canada. The itinerary for the Mission was as follows:

Contact details for the organisations visited are included in Appendix B

Itinerary		
Date	Location	Visit /Meeting
28 October	Snyder, West Texas, USA	Kinder Morgan CO <sub>2</sub> Company L.P. – site visit to SACROC oilfield (CO <sub>2</sub> -EOR)
29 October	Houston, Texas	Kinder Morgan CO <sub>2</sub> Company L.P. NATCO Group ChevronTexaco Worldwide Power & Gasification Inc.  <i>Reception - British Consulate-General</i>
30 October	Washington, DC	BP US Department of Energy
31 October	Beulah, N. Dakota	Dakota Gasification Company – site visit to Great Plains Synfuels Plant (CO <sub>2</sub> pre-comb. capture)
1 November	Estevan, Weyburn and Regina, Saskatchewan, Canada	International Test Centre (ITC) for CO <sub>2</sub> Capture, University of Regina – site visit to pilot CO <sub>2</sub> capture facility at SaskPower's Boundary Dam Power Station (CO <sub>2</sub> post-comb. capture) EnCana Resources – site visit to Weyburn oil field (CO <sub>2</sub> -EOR) Petroleum Technology Research Centre (PTRC), University of Regina
4 November	Calgary, Alberta	Canadian Energy Research Institute (CERI) Canadian Clean Power Coalition (CCPC) ZECA Corporation
5 November	Edmonton, Alberta	Alberta Research Council (ARC) University of Alberta Alberta Energy and Utilities Board – Alberta Geological Survey CANMET Energy Technology Centre (CETC) - Devon
6 November	Ottawa, Ontario	CANMET Energy Technology Centre (CETC) - Ottawa  <i>Reception - British High Commission/CETC</i>
7 November	Ottawa, Ontario	Natural Resources Canada (NRCan) Environment Canada

### 3.3 Technology Areas and Other Issues

The Mission addressed primarily technology issues associated with CO<sub>2</sub> capture and geological storage, most notably those technologies that are being researched, developed, demonstrated or deployed in the USA and Canada and the experiences gained. It also explored associated techno-economic, legal, security, environmental, infrastructural, social, fiscal and political matters, as well as engineering challenges and risks. These areas are summarised in the following table:

## Technology areas and other issues

### CO<sub>2</sub> Capture

- Post-combustion capture (flue gas scrubbing routes)
- Oxy-fuel firing (O<sub>2</sub>/CO<sub>2</sub> recycle routes)
- Pre-combustion capture (hydrogen/syngas routes)
- Operation/systems
- Quality of CO<sub>2</sub>
- Economics/incentives

### CO<sub>2</sub> Transport

- Pipelines
- Transport economics
- Planning issues
- Environmental risks

### CO<sub>2</sub> Storage/Use

- CO<sub>2</sub> enhanced oil recovery (CO<sub>2</sub>-EOR)
- CO<sub>2</sub> enhanced coal bed methane (ECBM) production
- Geological/leakage issues
- Engineering/environment issues
- Social/political/legal/fiscal issues

### CO<sub>2</sub> Infrastructure

- CO<sub>2</sub> market/economics
- Emission trading
- Integration of capture, transport and storage/use systems

*The questions are included as Appendix C to this report*

*A summary of the Dissemination Seminar is included as Appendix D to this report*

## 3.4 Questions Addressed

The Mission team identified a list of questions that it sought to address on the Mission. These questions, which were categorised under the four broad areas listed above, were circulated to the organisations to be visited prior to the Mission commencing.

## 3.5 Dissemination Seminar in London

A one day Dissemination Seminar was held at the DTI Conference Centre in London on 15 January 2003 to promulgate the findings of the Mission to a wide group of stakeholders and interested parties. The event attracted around 110 participants from all the key parts of UK industry, academia and Government.



## 4 Policy issues and initiatives in the USA and Canada

### 4.1 Introduction

The Mission team met with both US Federal Government officials (**US Department of Energy's (US DOE's) Office of Fossil Energy**) and Canadian Federal Government officials (**Natural Resources Canada (NRCan), Environment Canada, CANMET Energy Technology Centre (CETC)**) during the visit. The purpose of these meetings was to discuss the policies, initiatives and incentives both Governments were providing to encourage the take up of CO<sub>2</sub> capture and storage technologies and to better understand the drivers underlying these activities.

Both Governments actively encourage the research, development and deployment of carbon management technologies as a part of an overall strategy for the reduction of greenhouse gas (GHG) emissions. It is important to note in this context that although the USA has declined to sign the Kyoto Protocol, it is still pursuing a vigorous programme to reduce CO<sub>2</sub> emissions in the medium term. The Canadian Government ratified the Protocol in December 2002.

In addition to government-led initiatives in the USA and Canada, a number of international collaborative programmes and public/private initiatives are underway in North America, often with US or Canadian (or in some cases both) Government participation. These include the **BP-led CO<sub>2</sub> Capture Project (CCP)**, the **International Weyburn CO<sub>2</sub> Monitoring and Storage Project**, the **Canadian Clean Power Coalition (CCPC)** and the development of advanced gasification concepts by **ZECA Corporation**. Meetings took place with all these groups during the course of the Mission.

In addition, both the US and Canadian Governments and their agencies are active participants in the **International Energy Agency's (IEA's) Working Party on Fossil Fuels (WPFF) Zero Emissions Technologies Strategy (ZETS)** and the complementary collaborative Implementing Agreements **IEA Greenhouse Gas R&D Programme** and **IEA Coal Research – The Clean Coal Centre**.

### 4.2 USA – Perspectives, Policy and Programmes

#### 4.2.1 US DOE's Energy and Cleaner Fossil Fuels Policy and "Vision 21"

The USA is highly reliant on coal for energy production and currently obtains over 50% of its electricity from this source. This reliance on coal is likely to continue in the long term as the country has considerable domestic resources. Alternative new technologies, such as renewables, are not currently considered to be either cost competitive or sufficiently reliable (although considerable RD&D programmes are currently underway to address these issues). Coal is also seen as a source for a range of chemicals and hydrogen.

The policy framework regarding energy in the USA is a complex picture. Although the USA has declined to sign the Kyoto Protocol, it acknowledges the need to tackle climate change and to develop carbon management strategies and technologies, including, significantly, those covering CO<sub>2</sub> capture and sequestration.

As major initiatives under his **National Energy Policy** (originally announced in May 2001), President Bush launched proposals for the Global Climate Change Initiative and the Clear Skies Initiative in February 2002.

The **Global Climate Change Initiative (GCCI)** proposes a rigorous, technology-led approach aimed at stimulating the development of new technologies, identifying market mechanisms and co-operating internationally on finding solutions and, as the science justifies, to "stop and then reverse" the growth in emissions. This initiative revolves around reducing GHG emissions through voluntary actions, rather than through mandated reductions or a cap on such emissions. President Bush proposed a voluntary 18% reduction in the ratio of GHG emissions to gross domestic product (GDP) from 2002 to 2012. This equates to a potential decrease of approximately 29 tonnes of GHGs per million dollars of GDP over the ten year period. It is proposed that this will be achieved by:

- Improving the national Emission Reduction Registry and providing transferable credits.
- Incentivising companies to voluntarily reduce emissions and monitor and report these reductions so that they are better prepared should a mandatory emission reduction programme be implemented in the future.
- Increasing funding from \$3.8 billion to \$4.5 billion for climate change-related activities and programmes, including \$1.3 billion on clean energy technologies (\$40 million on CO<sub>2</sub> capture and sequestration).

With respect to the **Clear Skies Initiative** (CSI), President Bush has proposed significant reductions in three pollutants (“3P”) – sulphur dioxide (SO<sub>2</sub>), oxides of nitrogen (NO<sub>x</sub>) and mercury (Hg). This proposed “3P” legislation would represent a considerable tightening of legislation from the existing Clean Air Act Amendments (CAAA) for SO<sub>2</sub> and State Implementation Plans (SIPs) for NO<sub>x</sub>, as well as introducing limitations on mercury emissions for the first time. The aim of the CSI is to reduce emissions of these pollutants by about two-thirds by 2018. The required reductions are even more dramatic if viewed against the projected 33% increase of generation across the time frame to 2020, which would require a 25% reduction in emissions concentrations simply to maintain current emission levels.

Overall, it seems likely that the CSI will trigger a new phase of SO<sub>2</sub> and NO<sub>x</sub> retrofit clean-up across the USA, with some plants being retrofitted with high efficiency abatement for the first time and other plants, with abatement already fitted, having their existing equipment significantly upgraded. All plants will have to consider mercury abatement for the first time.

The Bush Administration expected that these proposed initiatives would form key parts of a new **Energy Bill** to have been placed before Congress during the Autumn of 2002. With the new Republican majority of the legislature, the Administration were confident that such a Bill would have been passed. However, progress of the Energy Bill has been stalled due to issues concerning the exploration for oil and gas in Alaska and de-regulation of electricity markets – a situation likely to persist until the next Congress.

In the meantime, another Bill (the “**Jeffords Bill**”) has proposed “4P” legislation covering SO<sub>2</sub>, NO<sub>x</sub>, Hg and CO<sub>2</sub>. While this is viewed as unlikely to be enacted, it has served to raise the profile of GHG issues in the legislature.

However, a further recent development has also served to bring GHGs to the forefront on Capitol Hill. In early January, the Senate Commerce, Science and Transportation Committee held a hearing on GHG “cap-and-trade” legislation (the “**Climate Stewardship Act of 2003**”) that has been developed by Senators McCain and Lieberman. This Bill proposes that all major energy, industrial and transportation sources of the six major GHGs would have to limit their emissions to 2000 levels by 2010 and 1990 levels by 2016. While the Bill may not be passed out of committee, it is a marker and may reflect future US regulation of GHGs, as well as putting pressure on the Bush Administration to act on regulating GHG emissions rather than relying on the purely voluntary actions until 2012, as proposed in the President’s GCCI.

To achieve its goals with respect to climate change, the US Government’s focus is essentially on:

- plant efficiency;
- low carbon fuels; and
- carbon capture and storage.

As part of this, coal gasification is seen as a key technology for the future, although it is accepted that advanced combustion technologies will continue to have a role. Advanced turbines are also seen as an important aspect of greater efficiency in power generation. Important in the USA’s strategy is the reduction in costs of these new technologies in both their deployment and use.

Within the broad context of policy development outlined above, the strategic objective of **US DOE’s Office of Fossil Energy** in the power generation area is to provide technology to ensure continued electricity production from fossil fuel resources including:

- low cost environmental control technologies;
- low cost clean fuels (especially hydrogen); and
- zero emissions (including carbon), high efficiency, fuel flexible energy plants capable of multi-product output.

The outcomes expected from this strategic approach are expected to be:

- enhanced existing power plants retrofitted with competitive cleaner coal technologies (addressing SO<sub>2</sub>, NO<sub>x</sub> and particulates, as well as mercury emissions, which have been a cause of concern for some while in the USA);
- gasification technologies;
- “next generation” power plants for central and distributed generation covering advanced combustion, turbines and fuel cells (“Vision 21” – see below), zero emission plant using carbon management technologies including CO<sub>2</sub> sequestration; and
- clean, affordable fuels (e.g. hydrogen) for future transportation technologies.

The DOE has a number of initiatives and programmes currently underway to address these issues. These initiatives are an integral part of a “technology and commercialisation roadmap”, targeted at developing an advanced power plant concept - “**Vision 21**” (or more fully, the “21st Century Energy Plant”). This is a strategy that consists of various intermediate stages and deliverables en route to delivering this concept. Vision 21 is essentially a set of long term strategic goals - an assemblage of technologies that constitute a “sequestration-ready” next generation power plant. It is not a separately funded programme or an initiative, more an outcome of a series of current and future programmes - a vision of the bringing together of a number of technologies which would result, by about 2015, in a commercially viable fossil-fuelled plant with:

- an efficiency greater than 60% (HHV) for coal systems, 75% (LHV) for gas-fired plant and thermal efficiency of 85-90% for cogeneration;
- near zero emissions of the usual pollutants and trace elements;
- 40-50% reduction in CO<sub>2</sub> emissions by efficiency improvement and 100% reduction using sequestration; and
- energy costs 10-20% lower than now.

Current initiatives underway that effectively form part of Vision 21 include:

- **The President’s Coal Research Initiative** - a programme of funding not only for R&D, but also for demonstration projects. This programme builds on the success of the Clean Coal Technology Demonstration Program (CCT Program) that commenced in 1986 and is now largely finished (the CCT Program supported 38 projects – of which eight are not yet completed – with a total value of more than \$5.2 billion, some \$1.8 billion of which was from Federal sources). The President’s Coal Research Initiative provides funding for both large- and small-scale research, R&D, and demonstration activities. The total Federal budget for this initiative in 2002 was \$338 million. The research and R&D elements of the initiative aim to develop the knowledge base and cover:
  - central power systems including gasification and advanced combustion;
  - distributed generation including fuel cells;
  - hydrogen from coal;
  - carbon sequestration (see Section 4.2.2 below); and
  - advanced research.

Two sub-programmes form part of this initiative and address demonstration:

**The Power Plant Improvement Initiative** (PPII). This initiative, which was a precursor to the CCPI (see below), had its roots in the power failures of 1999 and 2000 and the increasing concerns over the adequacy of the nation’s power supplies as a whole. The scheme, which ran in 2001 only, provided financial assistance for the commercial scale demonstration of advanced clean coal technologies capable of boosting the electricity produced by existing and new coal-fired (specifically) plants and thereby assuring the reliability of energy supply. Under this initiative, the DOE have committed \$51 million, more than matched by \$60 million of industry funding.

This funding has supported eight projects in seven States, covering optimisation of sootblowing, NO<sub>x</sub> reduction and multi-pollutant control. Only one project addressed gasification technology – a refractory wear monitor at the Polk County IGCC plant.

The **Clean Coal Power Initiative** (CCPI) which covers a 10-year cost-sharing programme between the US Government and industry to demonstrate emerging clean coal power generation technologies and to accelerate emerging technologies to commercial use. To support this, President Bush has pledged some \$2 billion over this period. The initiative has four stages which cover:

- 1 NO<sub>x</sub>, SO<sub>2</sub>, mercury and particulates control (2001-2006). The solicitation for CCPI 1 has closed with 36 proposals with a value of \$5 billion submitted. Announcements concerning selected projects are expected early in 2003.
- 2 Efficiency and advanced pollutant controls to meet Clear Skies Initiative objectives (2004-2008).
- 3 Co-firing, membranes, fuel cells and advanced energy efficiency (2006-2011).
- 4 Near-zero emissions, sequestration, hydrogen production and further efficiency gains (2008-2015).

Particular elements within the President's Coal Research Initiative are identified as contributing to the Vision 21 goals (i.e. high efficiency with carbon management) or, conversely, are selected for funding under the Initiative due to their relevance to Vision 21.

#### 4.2.2 US DOE's Carbon Sequestration Program

As an integral part of the President's Coal Research Initiative (described above), the US DOE's Office of Fossil Energy and the National Energy Technology Laboratory (NETL) administer the US DOE's **Carbon Sequestration Program**. This programme is complementary to the Vision 21 related activities, specifically focussing on CO<sub>2</sub> capture and sequestration in a range of carbon sinks.

The work programme currently comprises a portfolio of core R&D activities in the areas of separation and capture of CO<sub>2</sub>, sequestration (direct storage and enhanced natural sinks), breakthrough concepts, measurement, monitoring and verification and non-CO<sub>2</sub> GHG control. The next logical step for this programme is to develop a number of regional partnerships (4-10), involving regional, state and local government entities, to determine the benefits of sequestration to regions (i.e. CO<sub>2</sub>-EOR, ECBM), develop regional inventories for sources and sinks, establish monitoring and verification protocols, address regulatory, environmental and stakeholder/outreach issues, and test sequestration technology at a small-scale. These regional partnerships, coupled with the existing core R&D activity, would enable first-of-a-kind "integrated power/sequestration demonstration(s)" to verify large-scale operation, highlight best technology options, verify performance and permanence, develop accurate cost/performance data and act as "international showcases".

The Carbon Sequestration Program currently supports some 60 diverse projects, providing about \$100 million in funding. The industry cost share represents about 40% of the total. The programme budget for 2002 was \$32 million and for 2003 it is expected to receive \$40-45 million. This compares to around \$1 million in 1997.

The programme aims to identify technology options that:

- are safe and environmentally acceptable;
- are cost effective and result in a less than 10% increase in the cost of energy services to customers for direct CO<sub>2</sub> capture and storage (i.e. in oil and gas reservoirs, unmineable coal seams, saline aquifers and oceans);
- result in costs of less than \$10/ton carbon for indirect capture (i.e. forestation/ re-forestation, mineralisation, agricultural practices, ocean fertilisation);
- contribute to reducing "carbon intensity" (i.e. with respect to GDP) by 18% by 2012 (i.e. the GCCI target); and
- provide a portfolio of commercially available technologies for assessment by 2012.

The programme has a number of pathways of investigation, examining the technologies as well as the commercial and environmental aspects:

- separation and capture (about 40% of budget):
  - pre-combustion decarbonisation
  - oxygen-fired combustion (“oxy-fuel” systems)
  - post-combustion capture
  - advanced integrated capture systems
  - cross-cutting science and technology.
- geological sequestration either for EOR, ECBM production, storage in saline aquifers or on the ocean bed (about 40% of budget):
  - monitoring, verification and remediation technology (key area)
  - health, safety and environmental risk assessment
  - knowledge base and technology for storage reservoirs.
- terrestrial/ocean and novel sequestration systems (about 20% of budget):
  - productivity enhancement (terrestrial)
  - measurement, prediction and verification
  - ecosystem dynamics
  - direct injection of CO<sub>2</sub> in deep oceans (funding reducing)
  - ocean fertilisation
  - biogeochemical processes
  - mineral conversion
  - novel integrated systems
  - cross-cutting science and technology.

Projects looking at CO<sub>2</sub> separation and capture are looking at improving performance, reducing costs and establishing protocols for current technology options such as amine scrubbing and oxy-fuel combustion, as well as looking at future technologies such as advanced sorbents, advanced membranes, solid sorbents and CO<sub>2</sub> hydrates.

The DOE’s Carbon Sequestration Program is involved in several major international collaborative projects including the BP-led CO<sub>2</sub> Capture Project (see Section 4.4.1), the International Weyburn CO<sub>2</sub> Monitoring and Storage Project (see Sections 7.2.1 and 8.1.2), the Canadian Clean Power Coalition (see Section 4.4.2), the ZECA Corporation technology development activity (see Section 4.4.3) and Statoil’s CO<sub>2</sub> migration monitoring activities at its Sleipner West Field in the Norwegian Sector of the North Sea.

Research priorities in the area of geological sequestration are:

- monitoring and verification methods/protocols;
- capacity evaluations;
- sequestration mechanisms;
- long-term integrity and permanence;
- environmental impacts; and
- safety.

Despite significant funding allocations and the lead being developed by the USA in this technology, it is clear that CO<sub>2</sub> capture and storage is still at a very early stage. Currently, all the commercial activity in the USA is associated with CO<sub>2</sub> use for EOR, where there is a commercial return. The SACROC project in the Permian Basin in West Texas (see Section 8.1.2), where Kinder Morgan CO<sub>2</sub> Company L.P. are using CO<sub>2</sub> to recover oil from wells which were close to commercial depletion, has been stimulated by Government tax and royalty holidays to make the investment worthwhile.

### 4.3 Canada – Perspectives, Policy and Programmes

#### 4.3.1 Canadian Government Cleaner Fossil Fuels Policy

Unlike the USA, the Canadian Government has (since the Mission returned home) ratified the Kyoto Protocol which means that it has accepted a legally binding target of reducing CO<sub>2</sub> emissions to a level of 6% below 1990 levels by 2008-2012. The Canadian Government estimates that the country's GHG emissions could reach 810Mt of CO<sub>2</sub> (equivalent) by 2010 under a "business as usual" scenario<sup>10</sup>. If it is to achieve its 6% Kyoto reduction target, then it must look to abate approximately 240MtCO<sub>2</sub>(equivalent), or 31% of the projected emissions. This is a formidable task when compared with the projected 90MtCO<sub>2</sub>(equivalent) under the UK's Climate Change Programme<sup>11</sup>.

Ratifying the Kyoto Protocol was not an easy decision for the Canadian Government, especially since the USA (by far its largest trading partner) has decided not to do so. This concern mainly revolved around the perceived competitive disadvantages that could result for Canada when compared to its neighbour, and the relatively demanding reduction target it had to meet. Further, Alberta (which is self-sufficient in energy) and Saskatchewan had serious reservations. The problems that will face Alberta become apparent when considering that the Province produces around 30% of Canada's GHG emissions but only has 13% of Canada's 30 million population. However, Canada's Federal Government decided that ratification would be in the country's best interest, having concluded that it could remain competitive with the USA. The Federal Government looks at the Kyoto target as a "national project" and that it must be achieved in partnership between the Federal and Provincial governments, with the risks managed and fairly shared amongst them.

The Canadian Government concluded that it was in a strong position to be able to do well. Amongst the various "new" technologies, it would be able to claim and hopefully maintain a competitive advantage in fuel cells, certain renewables (notably biomass), energy efficiency (notably in buildings) and CO<sub>2</sub> capture and storage.

Approximately 85% of Canada's GHG emissions derive from the production, transformation and use of fossil fuels, with the power generation, mining and oil and gas sectors being the largest emitter groups (referred to as the "Industry Group").

The Climate Change Plan for Canada allows for a step-by-step approach building on existing programmes and making adjustments as they progress. The plan has three steps to achieve the 240MtCO<sub>2</sub>(equivalent) reductions needed to meet Canada's Kyoto target:

- Step 1 – Actions Underway: existing initiatives under their Climate Change Action Plan 2000 are expected to save 80MtCO<sub>2</sub>(equivalent)/year. Note that this includes an anticipated 3.5MtCO<sub>2</sub>/year abated through CO<sub>2</sub> capture and storage activities already underway, e.g. Weyburn EOR; this component of AP2000 is expected to require C\$15 million of Federal support.
- Step 2 – New Actions: aim to save 100MtCO<sub>2</sub>(equivalent)/year by 2010 including emissions trading, demonstration of clean coal technology to save 4.5MtCO<sub>2</sub>/year and an expected 2.2MtCO<sub>2</sub>/year abated through further CO<sub>2</sub> capture and storage – likely to include the construction of the "backbone" of a capture and storage pipeline system, as presented in the Alberta Plan.
- Step 3 – The Remainder: a variety of possible initiatives are proposed, without firm details, to address the remaining 60 MtCO<sub>2</sub>(equivalent) "gap" (possibly involving more intensive consumer programmes and municipality actions).

To incentivise the reduction in CO<sub>2</sub>, the Government plans for a mix of instruments. These are:

- Innovation and technology – using leading edge technologies and cost sharing between the private sector and Government. Investment in technology would be increased particularly to promising new areas such as fuel cells, cleaner coal technologies, CO<sub>2</sub> capture and storage and distributed power systems.

<sup>10</sup> Government of Canada (2002) : "Climate Change Plan for Canada - Achieving our Commitments Together" 21st Nov ([www.climatechange.gc.ca](http://www.climatechange.gc.ca))

<sup>11</sup> DETR (2000) : "Climate Change - The UK Programme", White Paper CM4913, Presented to Parliament by the Secretary for the Environment, Transport and The Regions, London; The Stationery Office, Nov.

- Partnership Mechanisms – these would be led by the Federal Government, the Provincial Governments or at more local levels according to their needs and priorities. To support this a “Partnership Fund” would be established.
- Infrastructure – a climate friendly infrastructure would be developed which would include identifying a suitable proposal for developing a backbone for a CO<sub>2</sub> pipeline infrastructure for sequestration (see above “Step 2”).
- Emissions trading would include large industrial emitters, e.g. the power generation sector.
- Tax initiatives would allow for accelerated depreciation for renewables and excise tax exemption for ethanol. Other incentives could be made available later.
- Smart regulation.

#### 4.3.2 Canadian CO<sub>2</sub> Capture and Sequestration Initiatives

It is clear from above that CO<sub>2</sub> capture and sequestration will play a significant role in Canada’s plans to meet its Kyoto commitment. This is not surprising given that Canada is one of the leading countries in developing and demonstrating these technologies.

Canada has a variety of initiatives on CO<sub>2</sub> sequestration underway at Federal and Provincial levels, as well as a number of active public-private partnerships.

The Canadian Government recognises that action is required by it to assist with the commercialisation of the technology which, at the moment, is not economic in most instances. A number of areas have been identified where it believes action is required. These include:

- Regulatory and fiscal issues: CO<sub>2</sub>-EOR remains marginally uneconomic and incentives are needed to bring it to market. Hence a regulatory and fiscal regime is required which provides the framework to create a degree of certainty for the industry. For this, the Government is currently examining those mechanisms that encourage the development and use of CO<sub>2</sub> capture and storage technologies. They are also looking at what relevant Federal and Provincial tax and royalty mechanisms already exist or are needed to encourage its use. This could involve providing fiscal incentives such as tax breaks, royalty breaks and other incentives. This study of fiscal frameworks is due to report shortly and will be followed by modelling and analysis of the effect of changes in fiscal and legislative provisions on the post-tax income and rate of return of typical CO<sub>2</sub> projects. (A description of currently available tax credits etc, is provided in Section 9.4 of this report).
- Creating a favourable public policy environment: Public support for ratification was important and, in Canada, advertisements on television promote the need to reduce energy consumption to guard against climate change.
- Technology demonstration and information dissemination: Although the Weyburn oil field CO<sub>2</sub>-EOR project and the associated sequestration and monitoring activity is an international showcase project, it has required considerable support from not only the Federal and Provincial Governments, but also the USA and the EU (including DTI) in order to go ahead. This demonstration has shown that such projects can be very expensive and that government funding is critical.
- Working in partnership with industry: The costs of RD&D for CO<sub>2</sub> separation and capture are very high and incentives for work outside Government would be needed to encourage investment. There are, at the time of writing, some 41 CO<sub>2</sub> capture and storage RD&D projects, including the showcase Weyburn project in Saskatchewan. Much of the involvement by Government is either at the Federal level or Provincial level and is based on partnerships with industry.
- Information gathering: The Government also considered that there is a lack of knowledge on the best storage sites. It is planning therefore to complete an inventory of the most promising sites. This would involve working with Provincial bodies and others with an interest.
- Environmental issues are also of concern: Any risk of CO<sub>2</sub> leakage into the atmosphere has implications not only for the environment, but also for public health and safety. If geological sequestration was to be allowed under Kyoto, then accurate monitoring of seepages from storage sites would be essential. The Government considers this requires risk management to minimise such incidences and it is looking at:
  - The various geological media suitable for storage.
  - The degree of the risks involved.
  - Leakage – assessment of leakage potential.

- Monitoring techniques.
- What happens to the CO<sub>2</sub> within geological strata?
- The timescale over which leakage might occur – 1,000 years is thought to be reasonable.
- Providing transparent information to the public.

These issues were considered at an IPCC conference in Regina during November 2002.

The Federal Canadian strategy essentially consists of the following components:

- Sources of CO<sub>2</sub>:
  - High purity - from hydrogen, ammonia and fertilizer plants which produce CO<sub>2</sub> at low cost, e.g. Great Plains Synfuels Plant producing CO<sub>2</sub> for CO<sub>2</sub>-EOR at Weyburn. This is essentially the “low hanging fruit” but it only produces about 8Mt/year.
  - Low purity - from power and industrial plants. Greater quantities at about 67Mt/year, but more expensive.
  - Additional emissions associated with processing of sour gas (about 10Mt/year).
- Sinks and uses for CO<sub>2</sub>:
  - Revenue generating uses such as in EOR and ECBM. Capacity between 1 and 10Gt.
  - Meeting regulatory requirements (e.g. disposal of sour gas - hydrogen sulphide (H<sub>2</sub>S) and CO<sub>2</sub> - from natural gas production)
  - Storage in geological media – disused oil and gas wells and in saline aquifers. Capacity approx 10 to 100Gt.

Overall, the opportunity for CO<sub>2</sub> storage in Canada is huge: In western Canada, up to 12Mt/year could ultimately be used for CO<sub>2</sub>-EOR and up to 60Mt/year could be used for ECBM or disposal in saline aquifers. In terms of total sequestration capacity in Canada as a whole, up to 342Mt could be sequestered in oil producing reservoirs and 25Gt in coal beds.

**CANMET Energy Technology Centre (CETC) – Ottawa**, part of **Natural Resources Canada**, is the leading agency of Federal activity in the area of CO<sub>2</sub> capture and geological storage. CETC has a vision to underpin a sustainable energy future for Canadians through national collaboration in energy innovation by:

- reducing energy’s ecological impact;
- creating opportunities from Canada’s rich energy resources;
- ensuring affordable and reliable energy supplies;
- transforming how energy is generated and used;
- fulfilling societal and regional aspirations; and
- enhancing the security of energy supply and associated infrastructure.

To achieve this vision, CETC supports policy development through advice on issues and options, and policy delivery through science and technology programmes that are undertaken in partnerships with the private sector, academia and other levels of Government.

Furthermore, CETC attempts to influence private sector decisions on developing cleaner coal technologies through cost-sharing partnership projects. This is either achieved through contributing to projects, or providing its own laboratories and research and consultancy facilities. CETC’s aim is to take a balanced view of sustainable energy technologies by placing them all in a context, rather than developing them in isolation from other technologies.

Within the context of CO<sub>2</sub> capture and storage, CETC is very active in partnership projects, including some described later in this section. Importantly, CETC operates the **Canadian CO<sub>2</sub> Capture and Storage Technology Network (CCCSTN)**, which aims to co-ordinate activities undertaken by groups working on research, sharing of information, identifying technology gaps and barriers, and the development and implementation of national CO<sub>2</sub> capture and storage initiatives. It sees zero emissions technology as a natural evolution of Government initiatives for climate change technologies.

The key drivers of this programme are:

- the market price for carbon;
- regulation, with more demanding standards; and
- market opportunities such as EOR and ECBM.

It sees the key issues and needs as:

- CO<sub>2</sub> capture costs, efficiency, improved technologies and systems.
- effectiveness of storage using EOR and ECBM applications.
- storage capacity and cost of reservoirs, monitoring and verification.
- safety and integrity of subsurface storage and longer-term issues affecting “fixation” and “leakage”.
- regulatory mechanisms, royalty structures and ownership.

CETC sees its key tasks as:

- facilitating information sharing across all organisations involved in CO<sub>2</sub> capture and storage.
- identifying technology gaps and barriers that prevent CO<sub>2</sub> technologies moving forward.
- providing workshops and consultancy.
- providing a forum for co-ordinating requests for support.
- facilitating financial support for key projects.
- co-ordinating Canada’s relations with international activities.

To achieve its objectives, CETC sees “technology roadmaps” as key. The roadmap for CO<sub>2</sub> capture and storage (produced as a part of AP2000) identifies the technologies, processes and integration pathways needed to allow the deployment of CO<sub>2</sub> capture and storage in Canada through to 2020.

The Canadian Government, through CETC, has an active participation in a number of major international collaborative projects including the BP-led CO<sub>2</sub> Capture Project (see section 4.1.1), the International Weyburn CO<sub>2</sub> Monitoring and Storage Project (see Sections 7.2.1 and 8.1.2.2), the Canadian Clean Power Coalition (see section 4.4.2), the ZECA Corporation technology development activity (see section 4.4.3), the US DOE’s Carbon Sequestration Program (see section 4.2.2) and Statoil’s CO<sub>2</sub> migration monitoring activities at its Sleipner West Field in the North Sea.

#### **4.4 Other Activities Ongoing in North America**

##### **4.4.1 The CO<sub>2</sub> Capture Project**

A major international collaboration – the CO<sub>2</sub> Capture Project (CCP) – is currently underway, led by BP and involving seven other major energy companies (ChevronTexaco, ENI, Norsk Hydro, EnCana, Shell, Statoil and Suncor Energy). The project aims to reduce the cost of CO<sub>2</sub> capture from combustion sources and develop methods for safely storing CO<sub>2</sub> underground. The project team are working together with governments, NGOs and other stakeholders to deliver technology that is cost-effective and meets the needs of society. The project recognises that CO<sub>2</sub> capture and geological storage are only “bridging technologies” that will help move society towards cleaner fuels in the future.

The primary objective of the CCP is to develop new, breakthrough technologies to reduce the cost of CO<sub>2</sub> separation, capture and geological storage from combustion sources such as turbines, heaters and boilers. It will do this by performing desktop R&D (engineering studies, computer modelling, laboratory experiments) to prove the feasibility of advanced CO<sub>2</sub> separation and capture technologies (specifically targeting post-combustion methods, pre-combustion decarbonisation and oxy-fuel firing). Guidelines will be developed for maximising safe geological storage, for measuring and verifying stored volumes, and for assessing and mitigating storage risks. Economic models will be developed to establish lifecycle CO<sub>2</sub> separation, capture and sequestration costs for current and best technologies to compare alternatives and direct the R&D towards the most promising technologies. New technologies will be actively transferred to industry via publications, presentations, conferences, an Internet website, patent licenses and commercial services.

The project has a budget of \$25 million, 46% from public funds (21% from the US DOE; 13% from Norway’s Klimatek Programme; 12% from EU programmes) and 54% being provided by the industry partners. In addition, the industry partners are contributing “in-kind” support estimated to be worth a further \$25 million.

The CCP has a series of targets that are rigorously used in selecting technology options that warrant further consideration in achieving the stated aim of the project:

- 50% reduction in cost for existing facilities;
- 75% reduction in costs for new facilities;
- the development of a “proof-of-concept” by 2003/04; and
- a demonstration of the concept by 2010.

The project consortium was formed in 2000 and undertook a “review and evaluation phase” from April to August 2000. During this phase, five teams reviewed over 200 separate technologies against a broad criterion of “what could be taken to proof-of-concept in a three year timeframe and achieve the target cost reductions?” This led to 30 capture and 50 storage technologies being screened between August 2000 and September 2001, and 50 technologies becoming the subject of an “analysis phase”. From September 2001, some 80 contracts were established to analyse these technologies against a detailed set of criteria focusing on the project targets and, at the time of the Mission, around 20 technologies were likely to be the subject of a “focused technology development phase”, commencing in December 2002 for a 12 month period. Information was not available as to which technologies will form the basis of this next phase of activity, but four baseline scenarios were being established to underpin this development. These scenarios combine a capture approach, a transportation requirement and a sequestration approach, based on real operational situations.

More details of the CCP can be found on the Project’s website at [www.co2captureproject.org](http://www.co2captureproject.org)

#### 4.4.2 The Canadian Clean Power Coalition

The Canadian Clean Power Coalition (CCPC) is a public-private partnership which has the objective of researching and developing cleaner coal technologies and demonstrating that coal-fired power generation can effectively address the key environmental issues, including CO<sub>2</sub>. Membership not only includes 90% of Canada’s coal-fired power generation companies (ATCO Power Canada, EPCOR Utilities, Nova Scotia Power, Ontario Power Generation, Saskatchewan Power Corporation and TransAlta Utilities Corporation) and a major coal producer (Luscar), but also the Federal Government (Natural Resources Canada), the Alberta Energy Research Institute and Saskatchewan Industry and Resources. The Coalition is also collaborating internationally with the IEA Greenhouse Gas R&D Programme and Clean Coal Centre, and with the US Electric Power Research Institute (EPRI).

The underlying philosophy behind this partnership is that coal is vital for power generation (specifically, as regards this project, within Canada’s multi-fuelled electricity sector) in the long term, and therefore the implications for GHGs and air quality issues have to be addressed. It also aims to demonstrate a number of cleaner coal technology components which, although tested separately, have not been brought together. Whilst there are a number of projects for sequestering CO<sub>2</sub>, e.g. Weyburn, there are still no power generating plants with full scale CO<sub>2</sub> capture, although there is a test site at SaskPower’s Boundary Dam Power Plant where a flue gas sidestream is being taken from the main power station flue gas for testing on a pilot CO<sub>2</sub> capture plant (amine scrubbing) operated by ITC of the University of Regina (see Section 5.1.1.3 of this report).

The Coalition’s key aim is to build two full-scale demonstration projects for removing CO<sub>2</sub> and other emissions:

The first demonstration will involve retrofitting CO<sub>2</sub> capture technologies to an existing coal-fired plant by 2007. The technology options being evaluated for this are commercial or near-commercial technologies involving amine scrubbing of flue gas or oxy-fuel firing. It is anticipated that the demonstration will cost in the order of C\$500 million.

The second demonstration is intended to be the development, construction and operation of a new, full-scale “greenfield” coal-fired plant with CO<sub>2</sub> removal by 2010. Once again, only commercial or near-commercial technologies are being considered: This would most likely involve gasification technology and pre-combustion CO<sub>2</sub> capture. It is estimated that this demonstration will cost in the order of C\$1 billion.

Phase 1 of the project (conceptual engineering and feasibility studies) has been underway since September 2001 and is due for completion in mid-2003. This will identify technologies to be used in the two demonstrations. The budget for Phase 1 is C\$5 million, one third provided each by private

industry, the Federal Government and Regional Governments. Phase 2, comprising detailed engineering and construction of the first of the two demonstrations, is scheduled to commence in late 2003.

More details of the CCPC activity can be found on its website at [www.canadiancleanpowercoalition.com](http://www.canadiancleanpowercoalition.com)

#### 4.4.3 ZECA Corporation

ZECA Corporation (formerly the Zero Emissions Coal Alliance) is a private-public partnership developing a zero emission power plant concept based on hydrogasification, pre-combustion decarbonisation and fuel cell technologies. Further details of the partners and the technologies is given in Section 5.3.2 and on the company's website at [www.zeca.org](http://www.zeca.org)

### 4.5 Comparison with UK Policy on CO<sub>2</sub> Capture and Storage

The PIU Report on energy policy, published in February 2002, as well as the review into the case for Government support for a cleaner coal technology demonstration plant (both referred to in Section 1), concluded that CO<sub>2</sub> capture, with the opportunities for storage under the seabed of the North Sea, had potential for the future of fossil fuel generation and recommended that the feasibility of this technology be examined further. An Energy White Paper is due to be published in 2003, and a feasibility study into CO<sub>2</sub> capture and storage, which will inform UK Government policy, is due for publication in April 2003. It is not possible at this stage to draw totally valid comparisons with the USA and Canada, however the Mission team produced a set of provisional findings which it felt could be used in stimulating a CO<sub>2</sub> industry in the UK; these were fed into the White Paper team in November 2002.

Although the UK Government has recently announced its approach towards CO<sub>2</sub> capture and storage (see above), some research work has already been undertaken under the Foresight Programme looking at zero emission technologies (referred to in Section 1). Furthermore, some British Companies, such as BP, are already investigating the possibilities of using CO<sub>2</sub> for EOR (and enhanced gas recovery) in the North Sea.

However, it is clear that both the USA and Canada are far ahead in researching and demonstrating these technologies (apart from CO<sub>2</sub> storage in aquifers). The opportunities presented through their geographical position and the size of their countries, provides them with considerable scope for developing CO<sub>2</sub> infrastructure more easily than can be developed in the UK. This is due, in part, to a mature CO<sub>2</sub> supply industry (using natural underground sources of CO<sub>2</sub>) that has already developed in parts of the USA for EOR as a security of supply strategy. Whereas nearly all of its infrastructure growth will be land based, in the UK it would be under the North Sea since this offers the greatest prospect for CO<sub>2</sub> storage. This creates a different set of economics for sequestration, even for EOR, that offers the most cost effective route towards developing a CO<sub>2</sub> infrastructure. It should be noted here that the UK has already been active, through the British Geological Survey (BGS), in the geological aspects of CO<sub>2</sub> storage in both the Weyburn and Sleipner projects.

Another key difference between the USA and UK is the extent to which the USA depends on coal-fired power generation – this dependence exceeds 50%. Furthermore, the USA is virtually self sufficient in commercially viable coal resources. In the UK, on the other hand, coal accounts for around 33% of electricity generation, with about half of the coal used being imported. Since the early 1990s, the UK has been increasingly moving over to natural gas-fired power generation which has made the need for the UK to address GHG emissions from coal-fired plant less urgent.

However, there is much to be learnt from the work carried out in Canada and the USA particularly on:

- the development of a regulatory and fiscal environment designed to encourage the take up of the technologies, in particular, encouragement for EOR through tax and royalty breaks and other mechanisms. Given the high cost of capturing and transporting CO<sub>2</sub>, the use of such incentives will be even more critical in the North Sea.
- the use of strong partnerships with industry to encourage the development and demonstration of these technologies.

- Government funding for R&D projects through to supporting the building of demonstration plants.
- exploring the benefits of international co-operation. Developing CO<sub>2</sub> capture and storage systems is hugely expensive and the burden of this can be shared through international collaborative projects.
- a clear strategy, which both countries have developed, with the aim of building power plants using zero emission technologies. This warrants further study in the UK. Such a strategy would be valuable in the UK for developing an infrastructure, especially given the benefits gained through the extra oil obtained using EOR and the delayed costs of decommissioning the existing North Sea infrastructure.
- the raising of public awareness of the benefits of CO<sub>2</sub> capture and storage in mitigating GHGs. Programmes such as advertising and reports would do much to make the public aware of the benefits these technologies could bring.

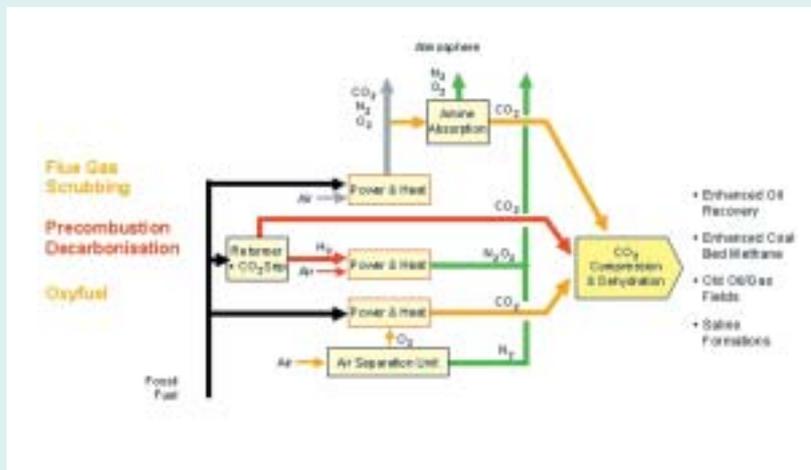
## 5 Carbon dioxide capture

Technologies for capturing CO<sub>2</sub> from power and heat processes utilising fossil fuels can be grouped under three broad categories:

- **Post-combustion** flue gas scrubbing routes, in which the CO<sub>2</sub> is scrubbed from the mixture of flue gases exiting the combustion plant.
- **“Oxy-fuel” firing** routes, in which the combustion process is fired with oxygen rather than air to create a flue gas primarily comprising CO<sub>2</sub>.
- **Pre-combustion decarbonisation**, in which a synthetic gas is produced from the fossil fuel (via a gasification process) and is decarbonised prior to combustion.

These three approaches to CO<sub>2</sub> capture are illustrated in the diagram below:

*Approaches to CO<sub>2</sub> Capture (based on a schematic from BP)*



The Mission included visits to a number of companies involved in the R&D, demonstration or deployment of technologies representing all three of these approaches.

### 5.1 Post-combustion Capture (Flue Gas Scrubbing Routes)

During the Mission, visits were made to **NATCO Group** in Houston, **BP** and the **US DOE** in Washington, DC, the **International Test Centre (ITC) for CO<sub>2</sub> Capture** at the University of Regina and ITC's pilot scale CO<sub>2</sub> capture plant at SaskPower's Boundary Dam power plant near Estevan in Saskatchewan, the **Canadian Clean Power Coalition** and the **CANMET Energy Technology Centre – Ottawa**; all have programmes or projects that address flue gas scrubbing technologies for CO<sub>2</sub> capture.

#### 5.1.1 Background to Post-combustion CO<sub>2</sub> Capture Technology

##### 5.1.1.1 General Position

There is a wide range of processes available for the capture of CO<sub>2</sub> (and other acid gases) from gas streams in general. Many of these have been used for dealing with hydrocarbon gas mixtures in the petroleum and gas industries since the early part of the 20th Century<sup>12</sup>. The choice of process will depend upon the composition of the gas stream and the CO<sub>2</sub> partial pressure.

The most suitable processes for separating CO<sub>2</sub> from gas mixtures can be summarised as :

- Absorption into an alkaline solution (such as an amine).
- Physical absorption into a solvent.
- Membrane permeation.
- Adsorption onto a solid.
- Methanation.

<sup>12</sup> Kohl, A L, and Nielsen, R B,1997. 'Gas Purification' Fifth Edition. Gulf Publishing Company, Houston Texas, 1999. ISBN 0-88415-220-0.

Absorption into alkaline solution is most suited to “high” gas flows of over 150m<sup>3</sup>/s, and “low” CO<sub>2</sub> partial pressures of under about 7 bar. At higher partial pressures, they are less cost effective than physical absorption processes.

Physical absorption into a non-reacting solvent is most suited to “high” gas flows of over 150m<sup>3</sup>/s, and “high” CO<sub>2</sub> partial pressures of over about 7 bar. High partial pressure is required in order to achieve a high solubility of the CO<sub>2</sub> in the solvent.

Membrane separation is most suited to “low” gas flows of under 150m<sup>3</sup>/s, and “high” CO<sub>2</sub> partial pressures of over about 7 bar. This is because membranes rely upon surface area, and do not achieve the economies of scale applicable to absorption processes. They also perform most effectively when there is a large difference in CO<sub>2</sub> partial pressure across the membrane.

Adsorption onto a solid is most suited to “low” gas flows of under 150m<sup>3</sup>/s, and “low” CO<sub>2</sub> partial pressures of under about 7 bar. The reasons are similar to those for membranes.

Methanation is most suited to “low” gas flows of under 150m<sup>3</sup>/s, and “low” CO<sub>2</sub> partial pressures of under about 7 bar. The cost of reagents would make this expensive for treating large quantities of CO<sub>2</sub>. (Methanation would not be suitable for the oxidising conditions present in flue gas.)

Absorption into an alkaline solution such as an amine has therefore become the most widespread option for CO<sub>2</sub> removal from large volumes of gas at low pressure. This applies to certain hydrocarbon gas mixtures, as described here, as well as to flue gases, as described in the Section 5.1.1.2.

A wide range of amines and mixtures of amines have been used for gas absorption and purification in the petroleum and gas industries – the majority of which are in fact alkanolamines. Triethanolamine (TEA) was the first alkanolamine to be used commercially for gas purification. However, this has now been largely displaced by other amines because of its low capacity for gas absorption, low reactivity and poor stability. The alkanolamines used most widely now are monoethanolamine (MEA), diethanolamine (DEA) and methyldiethanolamine (MDEA). However, diisopropanolamine (DIPA) and diglycolamine (DGA), 2-(2-amineethoxy) ethanol, are also widely used, as are the hindered amines such as 2-amino-2-methyl-1-propanol (AMP).

Sufficient data are now available to allow engineers to choose the best absorbent for each particular application, on technical and economic grounds.

MEA is currently the most common choice of reagent for the removal of CO<sub>2</sub> (or H<sub>2</sub>S) from gas streams at low pressure, particularly where a high removal efficiency is required. This is because its low molecular weight provides a high solution capacity at moderate concentrations, and it has a high alkalinity – being a primary amine. It can also be relatively easily reclaimed from contaminated solutions, and is cheaper than other amines. These advantages generally outweigh its disadvantages in these applications. The disadvantages are said to be that it forms irreversible reaction products with certain contaminants (carbonyl sulphide (COS) and carbon disulphide (CS<sub>2</sub>)), resulting in high amine losses; and its solutions are more corrosive than most other amines, particularly if amine concentrations exceed 20% and the solutions are highly loaded with acid gases such as CO<sub>2</sub>. However, several systems have been developed using corrosion inhibitors, to overcome these problems.

The licensors of amine scrubbing processes include Fluor, Dow Chemical, UOP, Shell International Petroleum, Union Carbide Corporation, BASF, Exxon Research and Engineering, Huntsman Corporation (formerly Texaco), Praxair and Mitsubishi Heavy Industries (MHI).

Literally hundreds of amine scrubbing plants, most using alkanolamines, have been constructed for the treatment of hydrocarbon gas mixtures in the petroleum and gas industries. Amine scrubbing for CO<sub>2</sub> capture from hydrocarbon gas mixtures is therefore very well established technology. However, it is apparent that significant developments and advances are still being made, and will continue to be made in the future. This is true for flue gas treatment, as well as for refinery and other hydrocarbon process gases, as discussed in the next section.

### 5.1.1.2 Amine Based Processes for CO<sub>2</sub> Capture from Flue Gases

The most established means of capturing CO<sub>2</sub> from combustion flue gases is by scrubbing the gas with an aqueous solution of an amine, primarily because the CO<sub>2</sub> partial pressure is normally within the range 0.3-0.15 bar. The depth and breadth of experience attained on amine scrubbing for CO<sub>2</sub> capture and other gas purification in the petroleum and gas industries is substantial. Over the last 25 years or so, this has been adapted for the capture of CO<sub>2</sub> from flue gases.

However, the flue gases generated from conventional fossil fuel power plants are different in many ways from the gas streams to which amine scrubbing has normally been applied in the petroleum, gas and chemical industries. Firstly, the CO<sub>2</sub> partial pressures are low, and it is this that causes amine scrubbing to be the favoured process over other options. Also flue gases have a much higher oxygen content than the above process gases. This can cause oxidation of amines to carboxylic acids and heat-stable amine salts, and can also accentuate corrosion problems.

Hot flue gases can cause amine degradation and reduce the efficiency of the CO<sub>2</sub> absorption process. Chapel, Ernest and Mariz<sup>13</sup> claim that the flue gas must be cooled to 50°C before it enters the absorber, by means of a direct contact cooler or a flue gas desulphurisation (FGD) plant, if fitted. Flue gases from coal firing can contain high levels of sulphur dioxide (SO<sub>2</sub>), traces of sulphur trioxide (SO<sub>3</sub>) and fly ash, and significant quantities of hydrogen chloride (HCl). Like the combustion products of gas firing, they can also contain significant quantities of nitrogen dioxide (NO<sub>2</sub>). Many amines, including MEA, react irreversibly with SO<sub>2</sub>, and SO<sub>3</sub>, producing stable salts that are not reclaimable, are highly corrosive to plant components and cause loss of amine. NO<sub>2</sub> also reacts with amines to produce heat stable salts that also give rise to amine losses.

The commercial consequences of the above issues are that capital and operating costs of amine scrubbing plants are very high. Costs are considered in more detail in Section 5.1.1.4. The highest contributor to operating cost is steam consumption for the stripper. In order to recover the amine and release CO<sub>2</sub> in the stripper, energy is required to provide the heat of reaction, sensible heat, and the heat of vaporisation of both water and amine.

There are conflicting requirements on the process: for example a high amine concentration increases the plant corrosion rate, but reduces the heat required for water vaporisation in the stripper. Reactive amines reduce absorber tower size and costs, but increase corrosion rates and regeneration costs.

The process vendors have been addressing these technical and economic issues in a variety of ways, so that a range of processes has and still is emerging. Some of the earliest process plants, those produced under the Kerr McGee license (now ABB Lummus Crest), used a 15-20% MEA solution<sup>14</sup>, which was fairly common in the petroleum and gas industries<sup>15</sup>. At this level, the amine concentration was low enough to avoid serious corrosion. Others, such as Fluor, used a 30% MEA solution, with an inhibitor to minimise corrosion and amine oxidation<sup>16</sup>. More recently, others have been developing amine mixtures or sterically hindered amines to boost process performance and reduce steam demand for regeneration, and also adopting alternative methods of controlling amine oxidation and corrosion.

Amine scrubbing processes have been developed for CO<sub>2</sub> capture from flue gases by a number of suppliers, including ABB Lummus and MHI. However, the Fluor Econamine FG<sup>SM</sup> process is the most widely established, and it is this process which is described here – as it would be applied to a gas turbine.

In the first stage of the process, the flue gases are cooled and saturated with water vapour in a direct contact cooler (DCC). This reduces the temperature of the flue gases to a suitable temperature for efficient scrubbing with an amine. If an amine scrubber was fitted to a coal-fired boiler, an FGD plant would be required upstream, and this would probably negate the requirement for the DCC.

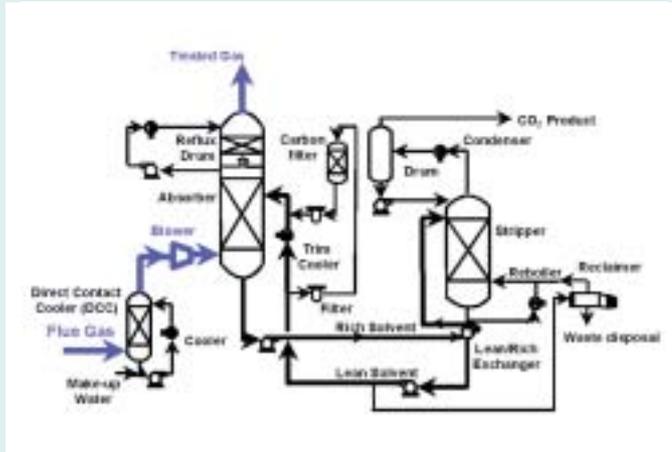
<sup>13</sup> Chapel, D, Ernest, J, and Mariz, C; 1999. 'Recovery of CO<sub>2</sub> from Flue Gases: Commercial Trends. Presented at the Canadian Society of Chemical Engineers Annual Meeting. Saskatoon, Saskatchewan, Canada, 4th to 6th October 1999. Paper Number 340.

<sup>14</sup> Mariz, C, 2002. 'Recovery of CO<sub>2</sub> from Flue Gases' Presentation made at IBC's Second Annual Carbon Sequestration Conference. Café Royal London, 15th to 16th May 2002.

<sup>15</sup> Kohl, A L, and Nielsen, R B, 1997. 'Gas Purification' Fifth Edition. Gulf Publishing Company, Houston Texas, 1999. ISBN 0-88415-220-0.

<sup>16</sup> Chapel, D, Ernest, J, and Mariz, C; 1999. 'Recovery of CO<sub>2</sub> from Flue Gases: Commercial Trends. Presented at the Canadian Society of Chemical Engineers Annual Meeting. Saskatoon, Saskatchewan, Canada, 4th to 6th October 1999. Paper Number 340.

Fluor  
Econamine  
FG<sup>SM</sup> Plant



After the DCC or FGD plant, the gases then pass through a blower to overcome the system pressure drop, before entering the amine scrubber, where CO<sub>2</sub> is removed by reaction with the amine. The flue gases are washed to remove residual amine, before being exhausted to atmosphere.

The scrubbing liquor, rich in CO<sub>2</sub>, is pumped to the stripper tower to release the CO<sub>2</sub> and regenerate the amine reagent. However, before reaching the stripper, the rich solvent passes through an indirect contact heat exchanger, where its temperature is raised by the recovery of heat from the "lean solvent" being discharged from the stripper.

A certain proportion of the lean solvent is recycled through the reboiler, where its temperature is raised by indirect contact with a steam supply from the power plant. An amine reclaimer is used in order to reduce amine losses caused by salt formation. Amine salts are reacted with sodium hydroxide to form sodium salts and the original amine. The recovered amine is returned to the process and the sodium salts are discharged to waste. In order to control suspended and dissolved solids in the amine liquor, a bleed stream is passed through activated carbon and mechanical filters.

#### 5.1.1.3 Research and Development Activity

There is a considerable amount of R&D being carried out by organisations other than the process suppliers. All of this was discussed on the Mission.

#### The International Test Centre (ITC) for CO<sub>2</sub> Capture, University of Regina.

ITC is a world leader in its designated field. Its facilities at the University of Regina and at SaskPower's Boundary Dam Power Station near Estevan in Saskatchewan were visited during this Mission.

ITC's Test Rigs  
at the  
University of  
Regina



Pilot Scale  
Facility at  
Boundary Dam  
Power Plant,  
Estevan

At present, the organisations participating in ITC's R&D programme include the US and Canadian Governments, the Provincial Governments of Saskatchewan and Alberta, the IEA Greenhouse Gas R&D Programme, Fluor, a coal supplier and three generating companies. These partners use the facility for a variety of tests on, for example, solvent and absorber packing performance, the evaluation of process integration to power plant and operational problem solving.

ITC's work includes:

- evaluation of thermodynamic and kinetic data on gas separation processes;
- selection and formulation of high performance solvents;
- investigation of solvent degradation and corrosion;
- development of corrosion protection systems, reactive membranes for gas separation, higher performance absorbers and regenerators;
- modelling and simulation of gas separation processes;
- process optimisation and cost studies; and
- process monitoring and control.

The Centre's staff have produced over 120 technical papers over the last 15 years or so. Their facilities include laboratories for bench scale research on solvent and packing performance, process kinetics and corrosion studies.

ITC have recently built a new pilot plant facility at the University in Regina. This is considered small enough to allow flexible operation, yet large enough to provide information that can be utilised for larger scale use, for example at their Boundary Dam pre-commercial pilot plant. It is designed for testing, among other things, column packings, separator units and membranes for CO<sub>2</sub> separation.

They also have a pre-commercial scale pilot plant test facility at Boundary Dam Power Station, which fires local lignite. This is used for testing process integration into the power plant system, and evaluating the technical and economic feasibility of processes and chemicals proposed through smaller scale studies in Regina. The plant is fitted with instrumentation to allow remote monitoring from Regina or elsewhere in the world through the Internet.

Through discussions with ITC's management it was apparent that stakeholders in CO<sub>2</sub> capture and storage from the UK could be well placed to participate in its R&D programme. This might offer an opportunity for UK companies to address some of the key issues arising from the application of amine scrubbing to UK power plants.

### **The Canadian Energy Research Institute (CERI)**

Recently, CERI has conducted an investigation into the costs for capture and geological sequestration of CO<sub>2</sub> in western Canada<sup>17</sup>. This includes an analysis of the costs of capture using the MHI amine scrubbing process when applied to a range of prototype flue gas sources, including four examples of coal-fired power plant. The study also includes a detailed sensitivity analysis on the effects of changes in certain input cost parameters such as equipment capital costs and process operating costs or energy consumption upon the overall cost per tonne of CO<sub>2</sub> captured. These data are available for analysis in order to identify the likely optimum power plant type for CO<sub>2</sub> capture in the UK, and the effects of power plant duty and capture technology advances upon the cost of capture.

### **The CENS Project (CO<sub>2</sub> for EOR in the North Sea)**

The CENS project is a scheme being developed to obtain CO<sub>2</sub> from large fossil-fired power plants in northern Europe and utilise this for EOR in the North Sea oil fields<sup>18,19</sup>, thereby reducing CO<sub>2</sub> emissions from the participating electricity generators. The project is being developed by Kinder Morgan CO<sub>2</sub> Company L.P., the largest CO<sub>2</sub> pipeline operator in the world, and Elsam, the largest power producer in Denmark.

<sup>17</sup> Fischer, L, Sloan T, and Mortensen, P, 2002. 'Costs for Capture and Sequestration of Carbon Dioxide in Western Canadian Geological Media' Canadian Energy Research Institute (CERI) Study Number 106. ISBN 1-896091-78-4. June 2002.

<sup>18</sup> Coleman, D, and Mai, B, 2002. 'CO<sub>2</sub> for EOR in the North Sea' Presented at IBC's Second Annual Carbon Sequestration Conference. Café Royal London, 15th to 16th May 2002.

<sup>19</sup> Sharman, H, Christensen, N P, Riley, NJ, and Lindeberg, E, 2003. "A CO<sub>2</sub> Infrastructure of the North Sea". DTI SHARP EOR Newsletter 4, January 2003 (<http://ior.rml.co.uk/issue4/CO2/INCO2/Summary.htm>)

The first power plant being targeted for CO<sub>2</sub> capture would be on the Danish coast, and capture would be achieved by amine scrubbing. The CO<sub>2</sub> would be compressed to 140 bar, and transported by submarine pipeline to the North Sea oil fields. The project partners hope to have this in service well within the present decade and are trying to involve power generators in the UK in the scheme; an early objective is to develop other CO<sub>2</sub> sources from the UK. The development of the first (Danish) phase of the project will be of considerable interest to potential UK stakeholders: This will include a detailed understanding of the issues surrounding the CO<sub>2</sub> capture plant.

#### **The Canadian Clean Power Coalition (CCPC)**

As described in Section 4.4.2, the CCPC is an association of coal producers, coal-fired electricity suppliers, two IEA Implementing Agreements, EPRI and the Canadian Federal and Provincial Governments. In addition to R&D on clean coal technology, the CCPC aims to construct two full scale demonstration plants for the removal of CO<sub>2</sub> and other emissions. The first of these will involve retrofitting equipment to an existing coal-fired power plant by 2007.

The technology options being evaluated for this retrofit demonstration are amine scrubbing of flue gases and oxy-fuel firing.

It would be very informative for interested parties in the UK to participate in, or in some way follow, the developments under these initiatives. The installation of a full scale commercial amine scrubber by the CCPC could be in place before that of the CENS project.

#### **NATCO Group's Membranes for CO<sub>2</sub> Separation**

As indicated previously, membranes have been used for gas separation for many years. They are most suited to high CO<sub>2</sub> partial pressures and low gas volumes. The Mission visited the SACROC oil field in Texas, where NATCO Group operates the world's first commercial membrane facility used for CO<sub>2</sub> separation/recycling from volatile and gaseous hydrocarbons associated with CO<sub>2</sub>-EOR production (see Section 8.1.2). The plant has been operated since 1983, and has recently been expanded to treat 5.1 million Nm<sup>3</sup>/day (approximately 60Nm<sup>3</sup>/s) of gas. The plant (using NATCO Group's "Cynara" extruded cellulose tri-acetate hollow fibre membrane technology), is much smaller and lighter in weight than the amine scrubber that preceded it, which makes it ideal for use offshore. Another similarly sized plant is now being constructed on an oil rig in the Gulf of Thailand. This is experience on an encouraging scale, but in order for membrane technology to be considered for use on flue gas streams, it must be demonstrated with flue gases at a considerably larger scale: A 500MW<sub>e</sub> coal-fired unit would generate about 500Nm<sup>3</sup>/s of flue gases, depending upon fuel quality and excess oxygen levels in the gases.

A NATCO Group "Cynara" Gas Separation Membrane Unit



### The CO<sub>2</sub> Capture Project (CCP)

The CCP, described in Section 4.4.1, is currently investigating a number of post-combustion CO<sub>2</sub> capture technologies as a part of the “focused technology development” phase. While the results of this activity are not yet available, the CCP Project team expressed the following messages to the Mission team:

- As already widely recognised, there are huge costs involved in the handling of flue gas streams – involving steam stripping, cooling, pressuring, etc.
- The largest variance in the total cost of CO<sub>2</sub> capture and storage was the cost of capture (variance of \$3-70/t compared to a total cost, including transport and storage, of \$6-90/t)

As far as post-combustion flue gas scrubbing for CO<sub>2</sub> capture is concerned, the CCP has concluded that amine scrubbing is the best available technology for this purpose<sup>20</sup>. The Project examined the requirements for an Econamine FG<sup>SM</sup> plant to capture 6,000 tonnes per day of CO<sub>2</sub> from an oil-fired combustion system at the BP Grangemouth refinery site. A very brief system description is provided on the CCP’s website, along with some cost estimates. These include an indicative capital cost of \$166 million for the Econamine plant. This may be a future source of additional information for UK stakeholders other than BP, on whose plant the study was carried out.

#### 5.1.1.4 Costs Overview and Potential for Cost Reductions

The most common large power generating units in the UK are 500MW<sub>e</sub> coal-fired boilers and these are the most likely candidates for CO<sub>2</sub> capture. The costs associated with one of these units have therefore been considered. One of these units would fire approximately 200 tonnes of coal per hour, and produce a little over 10,000 tonnes per day of CO<sub>2</sub>.

Chapel, Ernest and Mariz<sup>21</sup> estimate the operating costs of a Fluor Econamine FG<sup>SM</sup> plant producing 1,000 tonnes per day of CO<sub>2</sub> as \$18.7 per tonne of CO<sub>2</sub> captured. The major contributors to this are process steam, operation and maintenance (O&M) and electrical power. The same figures can be used as an upper limit of the current costs of an Econamine plant on a 500 MW<sub>e</sub> unit.

In order to put these costs into another perspective, it should be noted that the CENS Project team<sup>22</sup> suggest that for a highly efficient condensing steam turbine in Denmark, the unit efficiency would drop from 45% to 36%; a fall of 9 percentage points.

The 500MW<sub>e</sub> unit would result in roughly 2.5 million tonnes per year of CO<sub>2</sub> captured, at a 70% load factor. At a cost rate of \$18.7/t (£12.5/t) this would incur an annual operating cost of £31 million. It is suggested that these costs could fall in the future due to a reduction in stripper steam consumption, better integration of the stripper with the generating plant and a reduction in absorber packing pressure drop. MHI already claim to have made significant advances in all these areas and Praxair claim that the overall costs for the capture of a tonne of CO<sub>2</sub> could fall by as much as 60% over the next few years. If so, this would bring them to £12.4 million per year for a 500MW<sub>e</sub> unit.

The costs derived by Chapel, Ernest and Mariz and quoted above, assume that a FGD plant upstream of the amine plant could reduce the SO<sub>2</sub> concentration to less than 10vppm. Significantly higher concentrations would increase amine losses and raise the associated cost. The FGD process proposed for this duty involves the use of sodium hydroxide or carbonate and would produce sodium sulphate, which could be expensive to dispose of. There could therefore be an opportunity to reduce overall operating costs further by optimising FGD costs against amine losses, including an examination of the FGD process options.

<sup>20</sup> Simmonds, M, Hurst, P, Wilkinson, M B, Watt, C, and Roberts, C A, 2002. ‘A Study of Very Large Scale Post Combustion CO<sub>2</sub> Capture at a Refining and Petrochemical Complex’. Paper available on the Carbon Capture Project website [www.co2captureproject.org](http://www.co2captureproject.org)

<sup>21</sup> Chapel, D, Ernest, J, and Mariz, C; 1999. ‘Recovery of CO<sub>2</sub> from Flue Gases: Commercial Trends. Presented at the Canadian Society of Chemical Engineers Annual Meeting. Saskatoon, Saskatchewan, Canada, 4th to 6th October 1999. Paper Number 340.

<sup>22</sup> Coleman, D, and Mai, B, 2002. ‘CO<sub>2</sub> for EOR in the North Sea’ Presented at IBC’s Second Annual Carbon Sequestration Conference. Café Royal London, 15th to 16th May 2002.

Capital cost estimates from the CENS Project suggest that an amine scrubbing plant for one 500MW<sub>e</sub> coal-fired unit might cost very roughly £120 million. Simmonds and co-workers<sup>23</sup> estimated a capital cost of \$214 million for an Econamine FG<sup>SM</sup> plant with CO<sub>2</sub> drying and compression, which is designed for the recovery of 6,000 tonnes per day of CO<sub>2</sub> from an oil-fired combustion system. This suggests that plant designed for 10,000 tonnes per day would cost approximately £200 million.

At present there appears to be no detailed and consistent cost breakdown applicable to a large coal-fired boiler published in the open literature. Stakeholders such as the power generators will need to derive such costs before they can fully understand the business case for CO<sub>2</sub> capture from UK power plant. A significant reduction in the predicted costs of CO<sub>2</sub> capture compared to those quoted above, could have important consequences for future CO<sub>2</sub> capture and storage schemes – including those for EOR.

### 5.1.2 Amine Scrubbing: Operational and Practical Issues

Amine scrubbing is the best technology currently available for CO<sub>2</sub> capture from the flue gases of commercial power generating plant. The most important practical issue by far for a generating company, is to understand the costs of installing and operating such a system. As indicated above, there is a range of cost estimates available from a variety of sources, which vary considerably in their magnitude.

To this end, an early priority is to specify, obtain and evaluate a series of site specific design studies by the leading suppliers of the CO<sub>2</sub> capture technologies. These studies should address practical and engineering issues associated with a real site or sites, and should provide the first reliable estimates of costs – but still based on current understanding of the applicability and performance of the processes to power plant in the UK.

It would be advisable to commission such studies for more than one type of amine, and for more than one type of power plant – for example a coal-fired plant with existing FGD plant, a coal-fired plant without FGD plant, and a combined cycle gas turbine station. The studies should carefully address CO<sub>2</sub> capture plant integration into the existing power station. The primary issues are likely to be the number of boilers to be provided with CO<sub>2</sub> capture plant, whether the capture plant can be connected to alternative boilers, the effect of steam provision for the stripper, the impact on overall plant availability and flexibility and the locations of the stripper tower and amine scrubbers. The roles of the existing FGD plant booster fan and gas/gas heat exchanger could also be important.

It is also important to investigate possible cost minimisation initiatives, such as a reduction in tramp air in-leakage to the gas path upstream of the FGD plant. This would be costly, but would reduce the flue gas flow rate and therefore the design size and cost of the CO<sub>2</sub> capture plant gas path components.

#### 5.1.2.1 Application to Coal-fired Power Plant

In addition to the above design studies, it will be necessary to investigate possible operational problems arising from using amine technology on coal-fired plant in the UK. This would need to be done by experiment, probably in a pilot plant capable of operating on flue gases representative of those derived from UK solid fuels – accounting for the full range of fuels to be burnt.

The parameters that are likely to have an effect on the process performance include:

- flue gas temperature at the amine scrubber inlet;
- flue gas oxygen content;
- SO<sub>2</sub> and SO<sub>3</sub> content;
- NO<sub>2</sub> content;
- HCl content;
- fly ash content; and
- the detrimental effects that might be expected and the issues that need addressing include, amine losses, corrosion, aerosol formation, foaming and waste disposal.

<sup>23</sup> Simmonds, M, Hurst, P, Wilkinson, M B, Watt, C, and Roberts, C A, 2002. 'A Study of Very Large Scale Post Combustion CO<sub>2</sub> Capture at a Refining and Petrochemical Complex'. Paper available on the Carbon Capture Project website [www.co2captureproject.org](http://www.co2captureproject.org)

Information currently available suggests that for a 500MW<sub>e</sub> coal-fired boiler, amine losses could amount to about £3.5 million per year<sup>24</sup>, even if the inlet SO<sub>2</sub> content is reduced to less than 10vppm and NO<sub>2</sub> is held below 20vppm. Very few FGD plants can achieve outlet SO<sub>2</sub> concentrations approaching this level. It will therefore be necessary to invest in appropriate FGD technology to achieve this performance, and to address the effect on the cost of amine losses if a higher concentration is to be acceptable.

In order to achieve an FGD outlet SO<sub>2</sub> concentration of 5-10vppm, it will be necessary to considerably increase the performance of any FGD plant currently installed anywhere else in the world, or offered by any of the suppliers at present. This increase in FGD performance could probably be achieved by installing an additional scrubber tower or by adding a tray and an additional scrubbing loop.

Possible reagents for FGD “polishing” might include sodium hydroxide (or carbonate), lime or ammonia. The desulphurisation performance would have to be assessed and subsequently tested on a pilot plant.

If a coal-fired boiler was fitted with an selective catalytic reduction (SCR) plant to reduce NO<sub>x</sub> levels, this could significantly increase SO<sub>3</sub> levels in the flue gases downstream. A conversion rate of SO<sub>2</sub> to SO<sub>3</sub> of about 1% would not be unusual. Wet FGD scrubbers are very inefficient at removing SO<sub>3</sub>, so that in addition to SO<sub>2</sub> in the flue gases entering the amine scrubber, SO<sub>3</sub> levels alone might exceed 10vppm. This issue would require investigation.

NO<sub>2</sub> is known to react irreversibly with amines to form salts and contribute to amine losses, and the effect would need to be included in pilot plant studies.

Also the presence of amine salts is known to increase corrosion in amine scrubbing plant. This would need to be investigated in the context of fuels used in the UK – probably on a pilot plant.

Fly ash from coal-firing can cause foaming in the CO<sub>2</sub> absorber and stripper. This can lead to scaling and plugging of equipment, erosion, crevice corrosion, and increased solvent loss through chemical degradation and physical association with removed sludge<sup>25</sup>. Foaming propensity could be influenced not only by the level of contamination, but also by the ash composition, including its carbon content. Fly ash carbon content could be influenced by the nature of the in-furnace low NO<sub>x</sub> combustion system installed.

It has been suggested that soot from heavy fuel oil-firing, can stabilise an amine mist in a CO<sub>2</sub> scrubber and HCl is known to cause aerosol formation in ammonia. Aerosol formation should be looked for in pilot plant trials based on UK coals. If aerosol formation was a problem, it might be necessary to install an additional wet electrostatic precipitator after the CO<sub>2</sub> scrubber, incurring further costs.

The waste from the amine reclaimer could be expensive to dispose of. Disposal options will need to be considered, with a full knowledge of the composition and production rate of the waste.

Since coal-fired power plant are considered, at least by the CENS Project developers, as the most favourable source of CO<sub>2</sub> from within the UK, the need for pilot plant trials and design studies on coal-derived flue gases should be seriously considered by all stakeholders, including the UK Government.

#### 5.1.2.2 Application to a Gas Turbine

A gas turbine (GT) exhaust contains fewer types of contaminants than those from coal-derived flue gases, and are far less variable from one power plant to another. The main problems are likely to arise from the high oxygen content of the gas and the presence of NO<sub>2</sub>.

Amine scrubbing vendors have far more experience with GT flue gases than with coal-derived flue gases. There would therefore probably be no need to conduct pilot plant trials for potential GT

<sup>24</sup> Based on 10,000 te/d CO<sub>2</sub> capture, an amine loss of 1.6 kg/tonne CO<sub>2</sub> (Chapel et. al. 1999) and an amine cost of 87 pence per kg (59 US Cents per pound – Kohl and Neilsen, 1997).

<sup>25</sup> Chapel, D, Ernest, J, and Mariz, C; 1999. ‘Recovery of CO<sub>2</sub> from Flue Gases: Commercial Trends. Presented at the Canadian Society of Chemical Engineers Annual Meeting. Saskatoon, Saskatchewan, Canada, 4th to 6th October 1999. Paper Number 340.

applications in the UK. Nonetheless, before GTs are considered for CO<sub>2</sub> capture, a design study should be carried out and the GT exhaust composition should be carefully examined and compared with those for which the suppliers have commercial experience.

### 5.1.3 Amine Scrubbing: Implications and Lessons for the UK

Power generating companies, like any other business, will not make large capital investments, or commit to the burden of increased operating costs, unless it makes business sense to do so. The purchase and subsequent operation of CO<sub>2</sub> capture equipment on its power plant will incur very considerable capital and operating costs. This will be the case for amine scrubbing, oxy-fuel firing or any other technology.

The UK Government is therefore likely to have to provide the necessary business incentive if such a scheme is to be put in place in the UK.

At present, amine scrubbing is a leading candidate for the capture of CO<sub>2</sub> from existing power plants such as GTs or pulverised coal-fired stations. It is also likely to remain a leading option for new conventional subcritical or supercritical pulverised fuel-fired stations.

CO<sub>2</sub> capture by amine scrubbing is already a very well developed technology that has been used extensively in the petroleum and gas industries for almost a century. It has also been applied successfully to combustion flue gases for almost 25 years. It could be applied today if necessary, to gas, oil or coal-fired power plant and would be expected to achieve high CO<sub>2</sub> capture from the flue gases. There are at least four potential suppliers of the process technology.

However, the cost of building and operating such a plant on a large boiler in the UK would be very high indeed (£120-200 million), and would greatly increase the cost of electricity generation from that plant.

Also, it is clear that considerable advances are now being made on amine technology for CO<sub>2</sub> capture from the flue gases of large power boilers: These could dramatically reduce both capital and operating costs of this technology over the next few years.

It should also be recognised that there is still very limited commercial experience and even limited technical information on the operational performance of amine scrubbers on coal-fired power plant.

In this regard, it is worth reflecting upon the developments in FGD technology over the last thirty years. The first large scale application of FGD technology took place in the 1970s in the USA and Japan, and few problems were anticipated. However, many of these early plants experienced very severe problems of solid scale build-up, and the fouling blockage and corrosion of components. Over the next 20 years, plant designs were altered to reduce the corrosive potential of liquors, superior materials were developed and the process chemistry was improved. The Central Electricity Generating Board in England embarked upon pilot plant trials and other research in support of its intended FGD building programme. These studies demonstrated certain further design criteria and materials selections that proved to be very successful for the Drax and Ratcliffe FGD plants.

Over the 30 year period from the early 1970s to today, FGD plant costs have fallen to about 25% of their original level. It is interesting to reflect that many of the problems, the solutions and the advances made were not predicted before they were discovered.

This experience with FGD plant suggests that some unexpected and significant, if not serious, problems are likely to arise from the widespread application of amine scrubbing for CO<sub>2</sub> capture on fossil fuel-fired power plant. It would therefore be prudent to embark upon a R&D programme, in order to address possible problems of application to UK power plant.

However, a variety of governmental, industrial and academic organisations in Canada, the USA and elsewhere are already investigating these issues – at least in the context of their own national or business requirements. Many of these organisations appear willing to co-operate with new partners from their own or other countries. Collaboration with these bodies might provide the quickest and cheapest means of addressing the potential problems arising from the possible capture and storage of CO<sub>2</sub> from stationary combustion sources in the UK.

The British Government should promote the necessary RD&D work, in order to enable the UK stakeholders to evaluate the consequences and costs of adopting CO<sub>2</sub> capture and storage, as a means of meeting the UK's targets for reductions in GHG emissions.

## 5.2 Oxy-fuel Firing (O<sub>2</sub>/CO<sub>2</sub> Recycle Routes)

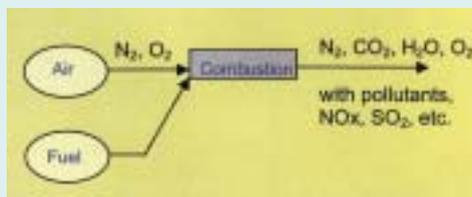
The Mission team had discussions relating to oxy-fuel firing as a route for CO<sub>2</sub> capture with **BP** and the **US DOE** in Washington, DC, the **Canadian Clean Power Coalition** and the **CANMET Energy Technology Centre – Ottawa**.

### 5.2.1 Background to Oxy-fuel Firing Technology

#### 5.2.1.1 General Position

Oxy-fuel firing (also known as O<sub>2</sub>/CO<sub>2</sub> recycle) is a means of combusting fuel (typically pulverised coal) in a conventional type steam generator (or oil/gas in a gas turbine) with the fuel being fired in an oxygen-rich atmosphere, or in an atmosphere where the ballast nitrogen (N<sub>2</sub>) in the atmosphere is replaced with CO<sub>2</sub>.

#### Conventional Combustion Air Firing

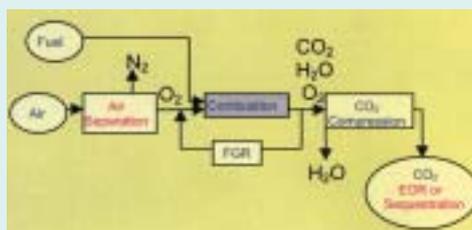


With conventional combustion-in-air, the inert N<sub>2</sub> in the atmosphere passes through the burners and boiler as ballast, slowing the rate of combustion and diluting the CO<sub>2</sub> in the exhaust gas. Typically, the proportion of CO<sub>2</sub> in the exhaust gas of a steam generator will be approximately 14% for pulverised fuel coal-firing, 8% with oil and 4% with natural gas.

The products of conventional combustion comprise CO<sub>2</sub>, steam (H<sub>2</sub>O), oxygen (O<sub>2</sub>) – being the excess O<sub>2</sub> not consumed during combustion – and other pollutants such as NO<sub>x</sub> and SO<sub>2</sub>. The ballast N<sub>2</sub> as it exhausts to atmosphere also carries a proportion of the heat generated during combustion, contributing to the efficiency losses of the process. The N<sub>2</sub> does, however, fulfil a vital role by slowing the rate of combustion and lowering the flame temperature.

For CO<sub>2</sub> capture, the O<sub>2</sub> for combustion is separated from the N<sub>2</sub> in an air separation unit (ASU) and diluted with CO<sub>2</sub> recirculated from the boiler or gas turbine exhaust (see diagram below). The proportion of CO<sub>2</sub> to O<sub>2</sub> will generally be set at a level appropriate for optimum performance of downstream plant and boiler heat transfer surfaces. In a retrofit application, the proportion of CO<sub>2</sub> to O<sub>2</sub> would be such that optimum performance would recognise the need to minimise the modifications required to downstream boiler surfaces. Generally this would be about 25-30% O<sub>2</sub> concentration in the CO<sub>2</sub>/O<sub>2</sub> mixture. In a new build, this percentage could be considerably higher.

#### Oxy-fuel Firing



The product of oxy-fuel firing is a flue gas consisting largely of CO<sub>2</sub> and steam, but also excess O<sub>2</sub> not utilised during combustion, ash particulates and other compounds arising from the oxidation of minerals and other elemental material in the fuel.

The steam can be readily separated from the flue gas stream by condensing, leaving, under optimum conditions, a flue gas consisting of some 90-95% CO<sub>2</sub>

by weight. This concentration of CO<sub>2</sub> with impurities may be sufficient for ECBM production or in sequestration into saline aquifers, however for EOR or other sequestration routes, additional purification will be required (typically using a cryogenic process). Compression of the CO<sub>2</sub>-rich flue gases for transport to the disposal location will enable some impurities to be separated from the CO<sub>2</sub>, however additional separation techniques may still be required.

### 5.2.1.2 Research and Development Activity

In both the USA and Canada, there was recognition from all the universities, research institutions, government bodies and companies visited during the course of the Mission that coal is, and will remain in the medium term, vital for electricity generation nationally and internationally. What was missing, however, from the long list of demonstration projects now in place for CO<sub>2</sub> capture and storage, were demonstration projects involving capture from power generation sources.

Although many pilot plants and research programmes have been undertaken, CO<sub>2</sub> capture is still, in most respects, an emerging technology when applied to power generation, with oxy-fuel firing one of the key elements of that technology requiring a practical demonstration.

Pilot testing of oxy-fuel firing on small-scale rigs has occurred at only two locations: Mitsui Babcock has tested oxy-fuel firing on a 160kW NO<sub>x</sub> reduction test facility at Renfrew in Scotland; and CANMET has a 300kW vertical combustor and flue gas treatment unit at their Energy Technology Centre in Ottawa. From discussions with the two groups, both appear to have performed very similar studies of the fundamental operational and practical issues of oxy-fuel combustion at different times over the last five years. In particular, investigations into NO<sub>x</sub> and SO<sub>x</sub> emissions, carbon-in-ash, in-furnace deposition and convective pass fouling have been undertaken.

The more recent work by CANMET for the Canadian Clean Power Coalition of a techno/economic assessment of the different CO<sub>2</sub> capture options for a range of boiler designs and fuel types, has now clearly established a lead for this group, although the UK facility has addressed a number of specific design options for oxy-fuel firing, such as:

- Operating at gas-side pressures significantly higher than atmospheric so that capital cost and operating cost savings could be achieved with the ASU and CO<sub>2</sub> compression/clean-up plant.
- Zero, or very low, rates of flue gas recirculation to the burner.

Co-operation between the two groups should therefore be investigated so that effort is not duplicated and maximum use is made of the (sometimes) limited financial and other resources available to the parties.

#### **The CO<sub>2</sub> Capture Project (CCP)**

The BP-led CO<sub>2</sub> Capture Project (see Section 4.4.1) is considering oxy-fuel routes for CO<sub>2</sub> capture in one of the post-combustion capture studies, however this study is not due to report until mid-2003. From the large number of capture technology options originally considered, 30 capture technologies were subsequently screened and a small number are currently being assessed in detail as part of the "focused technology development" phase.

The oxy-fuel firing studies (including chemical looping technology options) involve seven universities in the EU using as its baseline four configurations of power plant as representative types for capture. The results of these techno/economic studies will therefore provide a potentially valuable guide on the suitability and potential of this technology for CO<sub>2</sub> capture.

#### **US DOE's Carbon Sequestration Program**

This programme, described in Section 4.2.2, is committing approximately 40% of its \$32 million (2002) budget to the examination of CO<sub>2</sub> separation and capture technologies. This includes oxy-fuel firing, as well as post-combustion scrubbing, pre-combustion decarbonisation and other advanced integrated capture systems such as the use of advanced sorbents, advanced membranes and CO<sub>2</sub> hydrates.

An immediate target of the Carbon Sequestration Program is an international showcase demonstration of an integrated 100MW<sub>e</sub> power/sequestration project to be started during 2004. One of its key goals is a target of a less than 10% increase in the cost of energy when CO<sub>2</sub> capture is included. Oxy-fuel firing is a possible contender for such a demonstration.

### The Canadian Clean Power Coalition (CCPC)

The CCPC, described in Section 4.4.2, has a target to retrofit a large utility sized coal-fired plant with either oxy-fuel firing or other post-combustion capture technology by 2007.

Currently in Phase 1 of the C\$5m feasibility study, a pre-screening of the available technologies has been completed. The initial assessment concluded that the different capture technologies were comparable in terms of penalties and cost. Full studies are now in progress to assess in detail the technology options and costs for the retrofit plant options, as well as greenfield plant options, an emission control study (for NO<sub>x</sub>, SO<sub>x</sub>, mercury, particulates and all other pollutants except CO<sub>2</sub>), and an examination of CO<sub>2</sub> use and storage options.

When comparing oxy-fuel firing to amine scrubbing, it was noted that oxy-fuel firing has several advantages in the area of multi-pollutant management. Amine systems require the scrupulous scrubbing of SO<sub>x</sub> and also NO<sub>x</sub> to a lesser degree. The effect of mercury on amine scrubbing systems is also not well understood (although ITC's Boundary Dam test facility is investigating this issue). Amine scrubbing is therefore more appropriate when a very high quality CO<sub>2</sub> is required. With oxy-fuel firing, supported by downstream wet scrubbing (of particulates), an alkali can be employed to remove the nitrate compounds, while the SO<sub>2</sub> can be left as a liquid stream in the CO<sub>2</sub> depending upon the downstream use of the CO<sub>2</sub>. In an EOR application, this might not be possible (depending upon the miscibility pressure of the oil), however with ECBM or saline aquifer disposal, the SO<sub>2</sub> would not be a problem. In any event, a CO<sub>2</sub> concentration of >95% (and completely dry) is necessary for pipeline transportation in a dense phase.

The study, which is being undertaken by the CANMET Energy Technology Centre – Ottawa and described as being the most exhaustive of its kind, comprises a matrix of three existing Canadian power plants of different designs, firing three different coals (bituminous, sub-bituminous and lignite) with three different conversion techniques (including gasification). This study should therefore provide a useful marker for the suitability of the various technologies for world-wide application, although a full assessment will be required when (or if) the report is made available to outside bodies.

Phase 1 is due to report in Spring 2003, with Phase 2 (involving detailed engineering, permitting and construction) due to follow soon after.

Participation in the next phase of the project is still open to all parties.

### The CANMET CO<sub>2</sub> Consortium

The US DOE, Canadian Federal and Provincial Governments, various Canadian utilities, Fluor Daniel and McDermott Technologies (B&W Company) all provide funding for this research project led by the CANMET Energy Technology Centre (CETC) – Ottawa. This is an open consortium, with additional parties able to join the work programme.

The project is specifically looking at oxy-fuel combustion and its goal is to develop "elegant" oxy-fuel combustion techniques for enrichment and capture of flue streams. Started in 1994, the consortium is currently in Phase 6 of a work programme focused on O<sub>2</sub>/CO<sub>2</sub> combustion strategies for retrofit to an existing pulverised coal power plant. Its core research programme is aimed at:

- burner development (optimised for O<sub>2</sub>/CO<sub>2</sub> combustion);
- boiler performance simulation tools;
- multi-pollutant capture mechanisms; and
- advanced cycle development (with oxy-fuel combustion).

For the validation of oxy-fuel burner concepts (initially modelled using CFD techniques), the consortium uses a purpose built 300kW pilot plant, first used for oxy-fuel testing in 1995, since when over 100 tests have been completed.

*CETC-Ottawa's  
300kW  
Oxy-fuel Firing  
Pilot Rig*



The multi-pollutant capture research is conducted in a condensing heat exchanger environment, for removal of fine particulates, NO<sub>x</sub>, SO<sub>x</sub> and mercury. In such an environment, the SO<sub>2</sub> is readily removed using a bicarbonate solution. The mercury-related R&D (which they are actively pursuing) is specifically targeting the control technology aspects using two approaches – streams into the combustion gas to convert elemental mercury into an oxidised state, and within the condensing system from where they are trying to remove the mercury. This has involved extensive bench and pilot scale work using a proprietary process. The project involving the oxidation of mercury has been completed with promising results, and overall final process optimising testing is planned for early 2003.

The results of this work will feed into the Canadian Clean Power Coalition project for the retrofit of a utility plant by 2007.

#### **CANMET Oxy-fuel Field Demonstration Project**

This recently started five year project will design, build and test the world's first industrial scale oxy-fuel demonstration system for CO<sub>2</sub> capture, using initial seed funding of C\$600k from the Climate Change Action Plan. CETC – Ottawa will be responsible for optimising the whole concept, which will comprise a modular designed and trailer sized gas/oxy-fuel fired boiler with CO<sub>2</sub> compression included. It is being designed for use at a variety of geological sequestration sites for research into ECBM recovery and EOR:

- for ECBM – raw flue gas compression of the whole stream: 20%<CO<sub>2</sub><80% v/v
- for EOR – enriched product with CO<sub>2</sub> >98% v/v

The steam generated will drive a turbo-generator sufficient to power the auxiliary systems and compressor plant. For the development of oxy-fuel firing, the project will demonstrate the practices required for safe start-up, operation and shut-down for all applications of the technology including utility scale plant.

#### 5.2.2 Operational and Practical Issues

Recognised still as an emerging technology, there are many issues (some general for the technology, some specific for each application) which will determine whether oxy-fuel firing can be applied in a commercial application :

- uncertainties regarding boiler performance with recycled flue gas (CO<sub>2</sub>);
- air entrainment (will vary whether new-build or retrofit application);
- burner/combustion performance;
- boiler process issues;
- quality of CO<sub>2</sub> (dependant upon the sequestration method intended);
- auxiliary plant, parasitic shaft power; and
- CO<sub>2</sub> and pollutant removal from auxiliary plant.

For a boiler modified for oxy-fuel combustion, there will be a desire to maintain the same boiler surface configuration for continued operation with air combustion. With the gas recycling rate set to maintain the same steam outlet conditions, the change in flue gas composition with its different physical and thermal properties (and hence heat transfer characteristics) will have a large impact on furnace and convective surface performance. Work previously carried out on one particular boiler design showed that in the oxy-fuel combustion mode, the furnace heat absorption would increase with a lower furnace exit gas temperature. The pattern of steam and gas temperatures through the convective banks would continue to be lower, while the spray water flows would be higher. Overall, the boiler thermal efficiency would increase as a direct result of lower flue gas losses due to the lower mass of flue gas exhausted. However, this efficiency improvement would be offset by the increase in the overall auxiliary power requirements. It could be reasonably anticipated that a similar picture would arise for most boiler designs, however each would require specific analysis to decide the extent, if any, of modifications needed to the heat transfer surface arrangement. In this particular case, however, the differences in the performance of the different surfaces was such that no alterations to the surface were required.

The lower flue gas exit temperature expected during oxy-fuel combustion will give an increased risk of low temperature corrosion. This occurs when temperature conditions favour the condensation of sulphuric acid. Attention to this area may be necessary, with either a change in material at the economiser inlet and/or an increase in the temperature of the feed water to the economiser.

Air infiltration is a fact of life on large boiler plant. For safety reasons, these boilers operate under suction from the burner exit (i.e. in the furnace chamber) through to the induced draft fan. Hot gases are therefore prevented from leaking out of the boiler casing; any leakage is of cold air into the flue gas stream. In conventional plant, such in-leakage represents a loss in efficiency and active measures are taken to keep such infiltration to a minimum. The major sources of air in-leakage are through openings in the furnace membrane wall and penetrations in the boiler casing for the hot pipework to the heat transfer surfaces, at the air heater, at the induced draft fan and through any penetrations in the ducts, precipitator casings, etc. There is also controlled in-leakage at the mills, where seal air fans provide a pressure seal to prevent coal dust escape.

Obviously, any air leakage has a detrimental effect on the efficiency of the proposed process as it can significantly increase the duty of the CO<sub>2</sub> separation plant. Two of the main infiltration sources can be removed – the air heater being redundant in the modified plant, and the mill seal air can be replaced by recycled flue gas. However, some air infiltration is inevitable and must be allowed for in the process design.

The operation of the burners under conditions of oxy-fuel firing still gives some issues of concern, particularly in terms of flame stability, NO<sub>x</sub> emission, unburnt loss, flame luminosity, flame length and the slagging/fouling characteristics of the ash arising from the change in combustion. However investigation into all these issues and more are well advanced.

Another important operational issue with oxy-fuel combustion concerns the transport of the coal to the burners. With air firing, the mill outlet temperature is typically controlled to around 70-100°C by the addition of cold tempering air at the mill inlet. The maximum allowable mill outlet temperature is constrained by the materials of the flexible couplings in the pulverised fuel pipework and, more fundamentally, the volatile matter in the coal – the lower the coal volatile content the higher the acceptable mill outlet temperature:

Lignite	: 52-60°C
High Volatile Bituminous	: 66°C
Low Volatile Bituminous	: 66-82°C
Anthracite	: 93-99°C
Petroleum Coke	: 93-121°C

However, if recycled flue gas is to be used to dry and transport the coal to the burners, it should not be allowed to fall below around 130°C (i.e. the acid dew point). Whilst it may be possible to tolerate this higher temperature (after modifications are made to the pulverised fuel pipework system), as a result of lower O<sub>2</sub> content if the O<sub>2</sub> is added to the primary comburant after the pulverising mills, the possibility of treating this portion of the flue gas must be considered. Such treatment would involve chilling the flue gas to below the dew point to remove the acid components (SO<sub>2</sub> and SO<sub>3</sub>) in solution

along with much of the moisture, followed by reheating to the required mill inlet temperature.

One other major consideration for the implementation of an oxy-fuel system, is the safety and operability of the boiler. Implementation of oxy-fuel firing will require modifications to the boiler control systems including the boiler safety interlocks and tripping systems, and this will impact on the plant operating procedures even when firing in the conventional manner. Some of these changes are likely to affect boiler availability and turndown when oxy-fuel firing, however all these control issues are ones which can be resolved using tried and trusted technology.

### 5.2.3 Implications and Lessons for the UK

Unfortunately, no specific technical or economic issues came to light during the Mission in relation to oxy-fuel firing, as all the relevant projects in the USA (i.e. the CCP) and in Canada (the techno/economic evaluation for the CCPC) have not yet reached their reporting stages. It was clear, however, that unless a major developmental leap is made with membrane technology or one of the other capture technologies, oxy-fuel firing will be one of the key CO<sub>2</sub> capture technologies alongside amine scrubbing - depending largely on the configuration of the required plant and purity of CO<sub>2</sub> required for the method of sequestration method employed.

That all the projects identified are so well advanced and have such strong Government backing (especially in Canada), highlights the immediate need for similar support in the UK. Such support would go some way to ensuring that the UK and UK industry will not be left to buy-in the know-how when the application of this technology is required. The time frame is not too late for this to happen; for example there is an opportunity to be involved in the next phase of the CCPC CO<sub>2</sub> capture and storage project starting next year and leading to the retrofit of a coal-fired utility plant by 2007.

With the strong backing from Government, the Canadian organisations visited during the Mission (such as CETC-Ottawa, the Alberta Research Council and the University of Regina) are all proactive in the international bodies addressing GHG and CO<sub>2</sub> capture. On the basis that "you only get out what you put in", Canada is set to gain enormously, with the UK inevitably lagging behind – assuming that the status quo is maintained.

If not actively involved in such research activities, UK industry will always be "looking in" and following. To be actively involved, UK industry requires Government support as the return on such investment and the degree of finance involved are too long and too great respectively for industry to make in what is an increasingly risk adverse and short term driven market place.

All the projects concerning oxy-fuel firing visited have either strong US and/or Canadian Government backing, with in most cases the industry representatives being supported by their respective Government (such as the B&W Company in the CAMNET CO<sub>2</sub> Consortium). UK industry, and the UK itself, requires the same commitment.

## 5.3 Pre-combustion Capture/Decarbonisation (Hydrogen and Syngas Routes)

During the course of the Mission, visits were made to a number of organisations involved in the development or deployment of pre-combustion decarbonisation of fossil fuels. These included **ChevronTexaco** in Houston, **US DOE** in Washington DC, **Dakota Gasification Company's** Great Plains Synfuels Plant near Beulah in North Dakota, the **Canadian Clean Power Coalition** and **ZECA Corporation** in Calgary, Alberta.

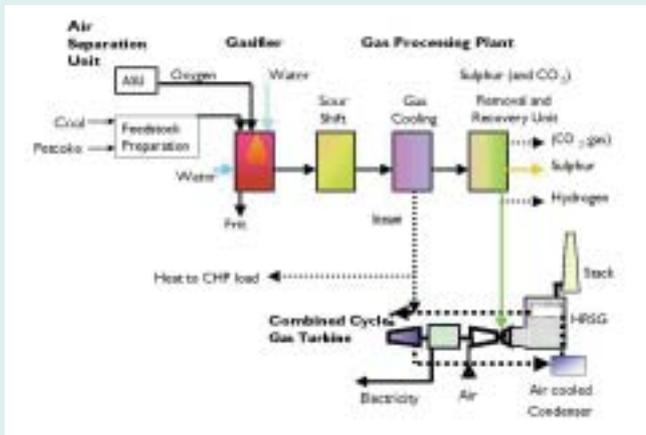
### 5.3.1 Background to Pre-combustion CO<sub>2</sub> Capture

#### 5.3.1.1 General Position

Pre-combustion CO<sub>2</sub> capture is possible through the use of integrated gasification combined cycle (IGCC) technology. In IGCC plant, a combined cycle gas turbine (CCGT) is designed to use a synthesis gas (syngas) manufactured from coal or other carbonaceous feedstocks.

In the manufacture of syngas, O<sub>2</sub> is produced in a cryogenic air separation unit (ASU) and fed to the gasifier, where coal is added. The two react to produce a syngas rich in carbon monoxide (CO) and steam. Ash from the feedstock, once it has passed through the gasification process, is removed as a hard glassy material. The CO and steam rich syngas is then converted in a catalytic shift conversion to

*A Schematic of  
an IGCC Power  
Plant with  
Pre-combustion  
CO<sub>2</sub> Capture*



Sulphur, which is present in the solid fuel prior to gasification, is recovered in its pure elemental state using physical solvents in a sulphur removal and recovery unit (SRRU). CO<sub>2</sub> can be captured at the same stage, before the syngas is combusted in the CCGT, through a scale up of the physical solvent plant. As described above, IGCC benefits from the CO<sub>2</sub> being at high pressure (typically 40-70 bar) and high concentration (typically 40%) at the time of removal.

The excellent environmental performance of gasification technology, particularly with regard to emissions of SO<sub>2</sub> and NO<sub>x</sub>, has been demonstrated in several international clean coal power stations.

As indicated earlier, the most common technologies that are used for CO<sub>2</sub> removal from gaseous streams are chemical solvents and physical solvents. Chemical solvents, such as MEA, MDEA, DEA and solutions of potassium carbonate, have a high capacity to absorb CO<sub>2</sub> at low pressure and low concentration. As such, they are the preferred technology for removal of CO<sub>2</sub> from flue gases, where CO<sub>2</sub> concentrations are typically 3-14% at near atmospheric pressure.

Although these chemical solvents have high CO<sub>2</sub> absorption capacity at low pressure, this capacity tails off at higher pressure. Physical solvents, on the other hand, take advantage of Henry's Law, whereby the amount of CO<sub>2</sub> which can be physically absorbed in a solvent is proportional to the partial pressure. The partial pressure of CO<sub>2</sub> is governed by the pressure and concentration of CO<sub>2</sub> in a gas. Hence when CO<sub>2</sub> is to be removed from gas streams where it is present at high pressure and high concentration, physical solvents are preferred.

One benefit of the use of physical solvents for the removal of CO<sub>2</sub> at high partial pressure, is that far smaller quantities of solvent are required compared to use of chemical solvents. This leads to smaller plant size with lower capital cost.

The other main benefit of physical solvents is a much lower energy requirement per tonne of CO<sub>2</sub> captured. Chemical solvents require large quantities of energy to release the captured gas to regenerate the solvent. This is because absorption processes that operate at low pressure have a high reaction energy, which requires a large energy input for solvent regeneration. Physical solvents are regenerated through a let down of the pressure, which reduces the solubility of the captured gases. Typically the main energy requirement is restricted to that associated with solvent circulation within the capture plant.

Pre-combustion capture of CO<sub>2</sub> was first commercialised over fifty years ago, when Fluor and the El Paso Natural Gas Company developed a physical solvent suitable for CO<sub>2</sub> removal. This "Fluor Solvent" process utilised propylene carbonate as a solvent, operating at low temperature. It was selected primarily for its high solubility of CO<sub>2</sub>, together with relatively low solubility of methane.

As the technology has matured, other physical and hybrid physical/chemical solvents have been developed to meet specific process requirements for the capture of CO<sub>2</sub> and other acid gases such as H<sub>2</sub>S.

### 5.3.1.2 Overview of Commercially Proven Solvents

The following section gives an overview of the properties of some of the main commercially proven physical solvents that are in use. These are mainly used for acid gas removal from methane or other hydrocarbons, or syngas containing significant quantities of CO and H<sub>2</sub>.

Commercially proven physical solvents that are in use today include:

- Fluor Solvent (propylene carbonate) – Fluor;
- Rectisol (methanol) – Lurgi Oel;
- Selexol (dimethyl ether of polyethylene glycol) – UOP; and
- Purisol (normal methyl pyrrolidone) – Lurgi Oel

#### Fluor Solvent

Fluor Solvent is propylene carbonate and has a molecular weight of 102.

The relative solubility of various gases in Fluor Solvent at 25°C is as follows:

Hydrogen	1
Nitrogen	1
Methane	5
Carbon dioxide	128
Carbonyl sulphide	241
Hydrogen sulphide	421
Water	38,461

Fluor Solvent was developed for its capability to separate CO<sub>2</sub> from methane through a combination of relatively high CO<sub>2</sub> solubility compared to methane solubility. It is good for bulk CO<sub>2</sub> removal, where minimum loss of hydrocarbons is the main requirement.

#### Rectisol

Rectisol is methanol (CH<sub>3</sub>OH) with a molecular weight of 32.

The relative solubility of various gases in Rectisol at 25°C is as follows:

Hydrogen	1
Nitrogen	1
Methane	5
Carbon dioxide	50
Carbonyl sulphide	133
Hydrogen sulphide	167

Methanol has a relatively high vapour pressure compared to alternatives under normal process conditions and requires cooling or other measures to limit solvent losses. Methanol is, however, a relatively inexpensive solvent that is widely available.

Rectisol has been used for production of clean synthesis gas from oil or coal gasification.

#### Selexol

Selexol is a mixture of dimethyl ethers of polyethylene glycol, and has a formula of CH<sub>3</sub>(CH<sub>2</sub>CH<sub>2</sub>O)<sub>n</sub>CH<sub>3</sub>, where n is between 3 and 9.

The relative solubility of various gases in Selexol at 25°C is as follows:

Hydrogen	1
Nitrogen	1.5
Methane	5
Carbon dioxide	76
Carbonyl sulphide	175
Hydrogen sulphide	670
Water	55,000

It is suited for selective removal of H<sub>2</sub>S and other sulphur compounds from syngas, or for bulk removal of CO<sub>2</sub>. The process was first introduced around 30 years ago and, as of May 2002, there were 55 Selexol units in commercial operation. It has been the process usually chosen for selective removal of H<sub>2</sub>S from synthesis gas or landfill gas.

### Purisol

Purisol is normal methyl pyrrolidone (NMP) and has a molecular weight of 99.

The relative solubility of various gases in Purisol at 25°C is as follows:

Hydrogen	1
Nitrogen	1
Methane	5
Carbon dioxide	156
Carbonyl sulphide	425
Hydrogen sulphide	1,594
Water	625,000

This process is suited to selective desulphurisation of synthesis gas to fuel gas quality, for example for combustion in gas turbines, where it may be desirable for most of the CO<sub>2</sub> to remain in the cleaned gas for control of NO<sub>x</sub> formation on combustion of the gas in the gas turbine.

### 5.3.2 Operational and Practical Issues in the USA and Canada

#### ChevronTexaco, Houston

Texaco has been a market leader in gasification since 1948, with over 130 plants licensed in the last 52 years. It operates as both a process licensor and project owner. It sees IGCC as a current viable choice for clean coal power capacity, which requires low emissions of SO<sub>2</sub> and NO<sub>x</sub>. There has been a significant uptake of licensed syngas capacity between 1991 and 2000, with the addition of some 100 million Nm<sup>3</sup>/day of syngas production capacity for use in power generation.

The Texaco gasification process typically accepts a range of feedstock alternatives, such as coal, petroleum coke, heavy oil, Orimulsion or wastes, and partially oxidises them in a gasifier which is fed by oxygen. The O<sub>2</sub> is typically produced through cryogenic separation of O<sub>2</sub> from air. The process produces a synthesis gas rich in CO, with H<sub>2</sub>, N<sub>2</sub>, H<sub>2</sub>S, CO<sub>2</sub> and steam also present.

The requirement for sulphur capture is a process with high selectivity for sulphur removal, with low solvent regeneration energy requirements. To provide a clean synthesis gas for combustion in a gas turbine, the H<sub>2</sub>S is typically removed pre-combustion by a physical wash process at high pressure. To provide effective process conditions, the syngas is cooled to around 40°C prior to sulphur removal. Sulphur removal is usually followed by the recovery of elemental sulphur in a Claus unit. All these processes are mature petrochemical and refinery operations. EPRI reported in 1987 that the Selexol and Purisol processes were suited to this application, and the Selexol process has been demonstrated in the Cool Water (USA), Sarlux (Sardinia, Italy) and API Energia (Italy) IGCC plants, which use Texaco gasifiers.

The current Texaco IGCC reference plant (TEPCO, Florida) provides for greater than 98% sulphur removal using conventional, low temperature, H<sub>2</sub>S removal from syngas using technology that is proven in the chemical and refining industries.

ChevronTexaco see the next generation of IGCC plants being capable of low cost CO<sub>2</sub> capture, with a relatively low penalty from loss of thermal efficiency. In this design, a saturated syngas produced by the gasifier, and which is rich in CO and steam, is converted by the following water gas shift reaction:



This yields a high pressure syngas rich in CO<sub>2</sub> and H<sub>2</sub>. The acid gas removal unit is designed for low cost removal of both H<sub>2</sub>S and the CO<sub>2</sub>, yielding a H<sub>2</sub>-rich gas to be utilised in clean fuel applications. This technology is proven, to the extent that there are nine ammonia projects in China which already utilise this approach with ChevronTexaco gasification units. The captured CO<sub>2</sub> is recombined with ammonia to produce urea, which is a solid fertilizer.

This approach has also been adopted for a ChevronTexaco petroleum coke gasification unit to produce urea and ammonia at Coffeyville, Kansas.

The process has the following main steps relating to acid gas removal:

- quench gasification of petroleum coke;
- water gas shift reaction;
- gas cooling;
- H<sub>2</sub>S physical absorption with Selexol and solvent regeneration;
- CO<sub>2</sub> physical absorption with Selexol and solvent regeneration; and
- CO<sub>2</sub> purification.

This provides a high purity stream of CO<sub>2</sub> for urea production by reaction with ammonia. The ammonia is produced by reaction of the H<sub>2</sub>, which is the other product in this process, with N<sub>2</sub>. This approach could also be used for production of H<sub>2</sub> for clean fuel applications, together with the capture of CO<sub>2</sub> for use in EOR or ECBM applications.

## US DOE

The Mission team heard about current US perspectives on pre-combustion CO<sub>2</sub> capture. A recent paper co-authored by the US DOE's National Energy Technology Laboratory (NETL) at the Nineteenth Annual Pittsburgh Coal Conference in September 2002, concluded that :

"Gasification-based energy conversion systems, such as IGCC, can provide stable, affordable, high-efficiency energy production with minimal environmental impact. Recent studies have shown that these plants can be built to efficiently accommodate future CO<sub>2</sub> capture technology that could further reduce their environmental impact. The outstanding environmental performance of IGCC, makes it an excellent technology for the clean production of electricity. IGCC systems also provide flexibility in the production of a wide range of products including electricity, fuels, chemicals, hydrogen and steam, whilst utilising low-cost, widely available feedstocks. Coal-based gasification systems provide an energy production alternative that is more efficient and environmentally friendly than competing coal-fired technologies."

At the same conference a paper co-authored by the US Environmental Protection Agency (EPA) concluded:

"Overall, the outlook of IGCC technology is promising. The technology will receive further acceptance by one or more of the following developments:

- more aggressive deregulation of power markets will promote multi-product IGCC projects.
- more extensive use of emission trading allows IGCC to benefit from over-compliance, at least with regard to SO<sub>2</sub> and particulates, and hence enhance its cost effectiveness.
- the need for significant CO<sub>2</sub> reductions, due to climate change obligations, could make IGCC the technology of choice amongst the fossil-based options."

The US DOE has developed the "Vision 21" concept of a power plant for the future that could revolutionise the power and fuels industry within the next 15 years (see Section 4.2.1). It would process a wide variety of fuels, produce multiple products, and coupled with CO<sub>2</sub> capture and storage, would emit very little GHGs into the atmosphere. CO<sub>2</sub> capture is seen as ultimately being through chemical or physical separation methods. Development efforts are being extended to cost effective measures for sulphur control and air separation, together with measures for dealing with H<sub>2</sub> and CO<sub>2</sub> product gases.

Furthermore, in January 2002, the US DOE issued its carbon sequestration "technology roadmap" for pathways to sustainable energy (see Section 4.2.1). The research thrust on pre-combustion capture is centred around improvements in solvent performance and the development of membrane separation techniques. By 2006, the aim is to initiate a cost-sharing pre-commercial test of an advanced pre-combustion CO<sub>2</sub> capture system. The desired outcome is efficient, low-cost electricity and H<sub>2</sub> production from fossil fuels with low GHG emissions.

*Dakota  
Gasification  
Company's  
Great Plains  
Synfuels Plant*



**Dakota Gasification Company's Great Plains Synfuels Plant**

The Mission made a site visit to the Great Plains Synfuels plant near Beulah, North Dakota, operated by the Dakota Gasification Company (DGC). The plant was supported by a US DOE programme aimed at encouraging the production of synfuels following the oil shocks of the 1970s, and started gasifying lignite commercially in 1984. Over 16,000 t/day of lignite is fed to a gasification plant containing 14 gasifiers. The raw gas stream that exits each gasifier is first cooled in a waste heat boiler that generates steam. One third of the gas is sent to a shift conversion unit, where some of the CO and steam is converted to CO<sub>2</sub> and H<sub>2</sub>. This stream is recombined with the other two thirds of the gas and cooled to 35°C.

The mixed gas is then sent to the acid gas removal unit where CO<sub>2</sub> and H<sub>2</sub>S is removed by the Rectisol process. The cleaned product gas is then sent to a methanation unit, where it is passed over a nickel catalyst. This causes CO and the remaining CO<sub>2</sub> to react with H<sub>2</sub> to produce methane, the main product of the plant.

The acid gas removal plant comprises a removal column, where the CO<sub>2</sub> and H<sub>2</sub>S are captured by the Rectisol solvent, and a regeneration column, where the Rectisol is regenerated and the CO<sub>2</sub> and H<sub>2</sub>S are released through pressure reduction.

In 1997, DGC signed an agreement with PanCanadian Petroleum Ltd to deliver 1.5-2.0Mt/year of CO<sub>2</sub> for use in EOR operations at their Weyburn oil field. The contract meant that PanCanadian (now EnCana Resources) would take some 40% of the total available CO<sub>2</sub> captured in the synfuels plant. Delivery of the first CO<sub>2</sub> to Weyburn commenced in September 2000, and this plant now demonstrates the feasibility of large scale pre-combustion capture of CO<sub>2</sub> by physical solvents for commercial application in EOR. More details concerning the Weyburn operation, and the supporting research programme looking at the fate of the CO<sub>2</sub> injected, are given in Sections 7.2.1 and 8.1.2.

### The Canadian Clean Power Coalition (CCPC)

The structure and activities of the CCPC are described in Section 4.4.2 and the technical options for the first of the two demonstrations planned (i.e. the retrofitting of CO<sub>2</sub> capture technology to an existing coal-fired power plant) are addressed in Sections 5.1.1.3 (amine scrubbing) and 5.2.1.2 (oxy-fuel firing).

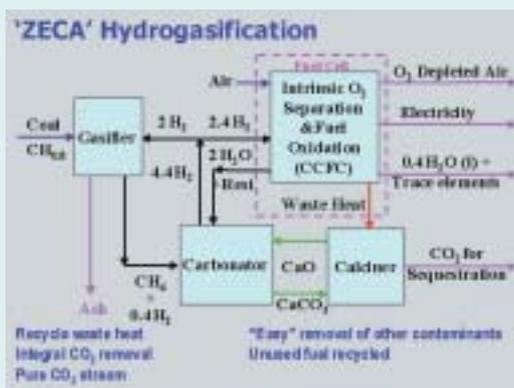
The second proposed demonstration is for the development, construction and operation of a full scale "greenfield" coal-fired project by 2010. This would probably involve gasification technology and pre-combustion capture/decarbonisation.

### ZECA Corporation

ZECA Corporation (formerly the Zero Emissions Coal Alliance) is a private-public partnership involving a number of US, Canadian and European organisations as shareholders (Arch Coal, Caterpillar, EPCOR Utilities, Fording Coal, Pinnacle West Capital Corporation, RAG Coal International, Salt River Project and the Coal Association of Canada) with some other members of the original alliance having options on shares (Alberta Energy Research Institute, Kennecott Energy, the US DOE's Los Alamos National Laboratory and Saskatchewan Power Corporation).

ZECA Corporation's key aim is to develop an emissions free plant concept involving a number of integrated chemical reactions in a system comprising a hydrogasifier, parallel reforming/carbonation chambers, a calciner and a solid oxide fuel cell (SOFC).

*ZECA Corporation Emissions Free Plant Concept involving a hydrogasifier, parallel reforming/carbonation chambers, a calciner and a solid fuel cell*



In essence, a fossil fuel is gasified with H<sub>2</sub> in the hydrogasifier to produce synthetic natural gas (SNG) which, together with steam, is passed through a bed of hot lime that reforms the SNG producing limestone and H<sub>2</sub> (half of which is product and half used in the hydrogasifier). This reforming process is then reversed (in practice, this would be achieved by using two parallel chambers, one absorbing carbon, one emitting carbon). The limestone is heated (using waste heat from the SOFC, other process heat or H<sub>2</sub>), forming lime and pure CO<sub>2</sub> (for sequestration). The SOFC, fed with the H<sub>2</sub> product from the reformer chamber, produces electricity and steam (used in the reformer).

The pure CO<sub>2</sub> stream is available for sequestration using any storage technology option, although ZECA Corporation, via their association with Los Alamos National Laboratory, believe that in the longer term, mineralisation is the best solution.

Work is ongoing within the partnership and elsewhere (including CETC-Ottawa and Los Alamos) to develop this concept cycle and verify the performance of its various component parts. Proposed future activities include:

- comparing the ZECA hydrogasifier/reforming steps plus CO<sub>2</sub> capture with existing gasifier configurations;
- exploring applications of ZECA technologies to existing and future oil sand operations;
- site specific evaluations; and
- conceptual case studies.

The longer term goal of ZECA Corporation is to complete a commercial scale demonstration of ZECA power plant technology by 2020.

### 5.3.3 Implications and Lessons for the UK

Both the USA and Canada are providing significant support to programmes involving fossil fuel gasification and pre-combustion capture of CO<sub>2</sub>, and there is a recognition that CO<sub>2</sub> capture through this route is linked to H<sub>2</sub> production. There is experience at Dakota Gasification Company's synfuels plant in North Dakota of large scale (1.5-2.0Mt/yr) pre-combustion capture of CO<sub>2</sub> from a coal gasification plant, with use in commercial EOR operations.

There will be an increasing demand for replacement generation capacity in the UK post 2005 with the closure of existing power stations. Use of advanced cleaner fossil fuel technology, such as IGCC with pre-combustion capture and storage, in next generation power stations, could lead to significant strategic benefits to the UK.

#### **Security of Supply**

Such developments would enable indigenous fossil fuels such as coal to be utilised in an environmentally acceptable manner through low cost pre-combustion CO<sub>2</sub> capture and storage.

If the captured CO<sub>2</sub> were to be used for EOR, it would provide a route to enabling increased recovery of indigenous hydrocarbons. Oil production in the UK Sector peaked in 1999, and many of the earlier larger oil fields are now producing at a small fraction of annual peak production. There is now a window of opportunity in the UK for incremental oil recovery through CO<sub>2</sub> injection. This would require low cost CO<sub>2</sub> to be available in significant volumes.

#### **Environmental**

IGCC technology would enable low emissions of SO<sub>2</sub>, NO<sub>x</sub> and particulates to be achieved, comparable to that from natural gas CCGT plant. Pre-combustion capture also provides a low cost route to CO<sub>2</sub> capture. Coupled with geological storage, this would provide low carbon emissions from fossil fuels.

The fuel produced is hydrogen, enabling carbon emissions to be reduced in sectors other than electricity generation, such as transportation. Hydrogen is seen as being used in increasing quantities as an energy carrier to supply stationary or transport fuel cell applications. This has been re-emphasised since the Mission by President Bush's announcement in February 2003 of a \$1.2 billion support package for "Hydrogen Economy" applications. IGCC at large scale could make low cost H<sub>2</sub> available in bulk, financed initially in the electricity market. This in turn could enable an earlier realisation of the "hydrogen economy".



## 6 Carbon dioxide transport in pipelines

As a part of the Mission, site visits were made to two pipeline operations supplying CO<sub>2</sub> for injection into depleting oil fields for the purpose of EOR. One of these pipelines was transporting CO<sub>2</sub> predominantly from naturally occurring underground formations, the other transporting CO<sub>2</sub> recovered from the production of synfuels from lignite.

While aspects concerning the long term storage of CO<sub>2</sub> in geologic structures will be addressed in Section 7, and the commercial use of CO<sub>2</sub> for EOR at these two oil fields will be described in detail in Section 8.1, this section of the report examines the pipeline transportation of CO<sub>2</sub>.

The first pipeline visited by the Mission team is owned and operated by **Kinder Morgan CO<sub>2</sub> Company L.P.** and supplies CO<sub>2</sub> to the CO<sub>2</sub>-EOR operation at its SACROC Field near Snyder, West Texas, USA. The second pipeline visited transports CO<sub>2</sub> from the Great Plains Synfuels Plant operated by **Dakota Gasification Company** near Beulah, North Dakota, USA, to a CO<sub>2</sub>-EOR operation being conducted by **EnCana Resources** (formerly PanCanadian Petroleum Ltd) at its Weyburn Field in Saskatchewan, Canada.

### 6.1 Background

Fiscal measures enacted in the USA in the 1970s and 1980s (e.g. the Oil Windfall Tax introduced by the Reagan Administration), aimed at encouraging security of energy supply and domestic oil production, have subsidised EOR operations and its associated infrastructure up to the present day. Further details of the current fiscal support for CO<sub>2</sub>-EOR in the USA is provided in Section 9.4.

Large gas fields with high purity CO<sub>2</sub> were discovered by accident in the search for natural gas deposits. The exploitation of these natural accumulations of CO<sub>2</sub> has led to abundant, cheap supplies of high quality CO<sub>2</sub> – an ideal “working fluid” for gas injection EOR operations (see Section 8.1).

The most practical way to transport the large volumes of CO<sub>2</sub> needed for onshore EOR operations is via pipeline.

This extensive use of CO<sub>2</sub> for EOR operations has led to the USA having the largest network of CO<sub>2</sub> pipelines in the world and being the leader in the development and application of CO<sub>2</sub> pipeline technology. Kinder Morgan (who also operates natural gas and petroleum pipelines) are the largest transporter and marketer of CO<sub>2</sub> in the USA, owning the most extensive CO<sub>2</sub> pipeline network in the industry, with around 1,600km of pipelines and a net recoverable CO<sub>2</sub> reserve in excess of 140 billion m<sup>3</sup>. In the USA there are some 2,400km of trunk pipelines that carry around 114Mt of CO<sub>2</sub> per year (in dense phase) and supplying 700km of lateral lines to EOR operations. This compares with around 800,000km of pipelines carrying natural and hazardous gas. The CO<sub>2</sub> infrastructure supplying West Texas delivers around 22Mt of CO<sub>2</sub> annually to over 40 floods in the Permian Basin. The CO<sub>2</sub> for EOR operations is sourced from natural CO<sub>2</sub> fields in Colorado and New Mexico. A small amount of CO<sub>2</sub> recovered from purification operations at four natural gas plants (Val Verde) is also used: This CO<sub>2</sub> contains hydrogen sulphide (H<sub>2</sub>S) contamination and is therefore only suitable for use in sour gas (i.e. containing H<sub>2</sub>S) fields such as SACROC.

*CO<sub>2</sub> Supplies  
(million cubic  
feet/day) and  
Sources  
(courtesy of Kinder  
Morgan CO<sub>2</sub>  
Company L.P.)*



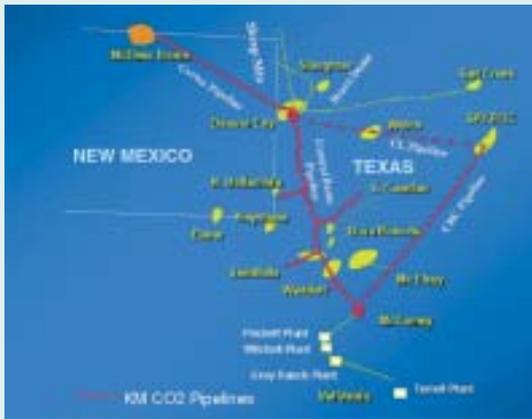
Another major CO<sub>2</sub> pipeline (330km in length) supplies CO<sub>2</sub> from Dakota Gasification Company's synfuels plant in North Dakota to an EOR operation at EnCana's Weyburn Field in Saskatchewan.

## 6.2 Operational and Practical Issues

The following sections consider the main CO<sub>2</sub> pipelines in the USA and Canada, together with construction, regulation and safety issues.

### 6.2.1 Permian Basin CO<sub>2</sub> Pipeline Networks

*CO<sub>2</sub> Pipelines and Oil Fields in W Texas and SE New Mexico (courtesy of Kinder Morgan CO<sub>2</sub> Company L.P.)*



#### McElmo Dome and the Cortez and McElmo Creek Pipelines

Primarily owned by Kinder Morgan (the operator) and ExxonMobil, the McElmo Dome is one of the world's largest known natural accumulations of nearly pure (98%+) CO<sub>2</sub> having an estimated 0.4 trillion m<sup>3</sup> of reserves (around 100 years supply). This dome produces from the Leadville formation at 2,440m with 44 wells that produce at individual rates up to 2.8 million m<sup>3</sup>/day. Due to increasing demand, both the McElmo Dome and its pipelines have recently been expanded by the installation of larger gathering lines to several wells, and by increasing compression and pumping capacity. Additional expansions are currently under consideration. Two pipelines carry CO<sub>2</sub> from the McElmo Dome: the 808km, 762mm (30") diameter Cortez Pipeline, operated by Kinder Morgan, carries more than 28 million m<sup>3</sup>/day of CO<sub>2</sub> to the Denver City Hub in West Texas, while the smaller 64km, 203mm (8") diameter McElmo Creek Pipeline, operated by ExxonMobil, supplies 1.7 million m<sup>3</sup>/day to their McElmo Creek Unit in Utah.

The Cortez Pipeline originates at an altitude of 2,280m which allows the CO<sub>2</sub>, once it has been pumped into the pipeline, to be gravity driven, without the need for booster pumping stations, to the 915m altitude at the line end. This does require the line to be decompressed en route to maintain the line within 103-145 bar limits.

#### Bravo Dome and the Bravo and Transpetco/Bravo Pipelines

Initially holding reserves of approximately 225 billion m<sup>3</sup>, the Bravo Dome covers an area of more than 360,000 hectares. This dome currently produces more than 11.3 million m<sup>3</sup>/day of CO<sub>2</sub> from more than 350 wells. Production here comes from the Tubb Sandstone at 700m. Recent developments include more than 40 new wells, as well as an upgrade to the compression plant. The 508mm (20") diameter Bravo Pipeline, owned by Occidental Permian, Kinder Morgan and Crosstimbers, runs 350km to the Denver City Hub and has a capacity of 10.8 million m<sup>3</sup>/day, delivering CO<sub>2</sub> at 124-131 bar. Major delivery points along the line include the Slaughter Field in Cochran and Hockley Counties, Texas, and the Wasson Field in Yoakum County, Texas. BP operates this pipeline on behalf of Occidental Permian. In 1996, Transpetco began operation of the Transpetco/Bravo Pipeline to the ExxonMobil-operated Postle Field near Guymon, Oklahoma. This 193km, 324mm (12<sup>3</sup>/<sub>4</sub>") diameter pipeline has a capacity of 5 million m<sup>3</sup>/day of CO<sub>2</sub>.

#### Sheep Mountain Field and Pipelines

The Sheep Mountain Field, owned by BP and ExxonMobil, is the smallest CO<sub>2</sub> source field serving the Permian Basin, with published initial reserve estimates of 57-85 billion m<sup>3</sup> of 97% pure CO<sub>2</sub>. BP is the operator of this field, which produces from 1,830m in the Dakota and Entrada formations in Huerfano County, Colorado. The Sheep Mountain Pipeline runs 296km southeast to the Rosebud connection with the Bravo Dome source field. This 508mm (20") diameter pipeline has a capacity of 9.3 million

m<sup>3</sup>/day. A separate 610mm (24") diameter pipeline with a capacity of 13.6 million m<sup>3</sup>/day runs 360km south to the Denver City Hub (at 141 bar) and onward to the Seminole San Andres Unit. BP and ExxonMobil own the northern portion of Sheep Mountain, while BP, ExxonMobil and Amerada Hess own the line south of Bravo Dome. BP operates both sections of this pipeline.

#### The Central Basin Pipeline

This pipeline, owned by Kinder Morgan, varies in diameter from 660mm (26") at Denver City down to 406mm (16") near McCamey, Texas. The present capacity of the line is 17 million m<sup>3</sup>/day, but if power were added, the capacity could be increased to 34 million m<sup>3</sup>/day.

#### The Este Pipeline

The Este Pipeline is 191km long, 305-356mm (12-14") in diameter, and is operated by ExxonMobil. Other major owners in the line include BP, Conoco and Occidental Permian Ltd. The capacity of the line is 7 million m<sup>3</sup>/day at Denver City and 4.25 million m<sup>3</sup>/day at the Salt Creek Terminus.

#### The Slaughter Pipeline

This pipeline, operated by ExxonMobil, is a 305mm (12") diameter line, with a capacity of approximately 4.5 million m<sup>3</sup>/day. The line runs 64km from Denver City to Hockley County, Texas.

#### West Texas and Llano Lateral Pipelines

Trinity Pipeline L.P. owns and operates these two pipelines. The West Texas Pipeline extends from the Denver City Hub 204km south to Reeves County, Texas. The Llano Lateral runs 85km off the Cortez main line. Both pipelines vary in diameter from 203-305mm (8-12") and have capacities of approximately 2.8 million m<sup>3</sup>/day.

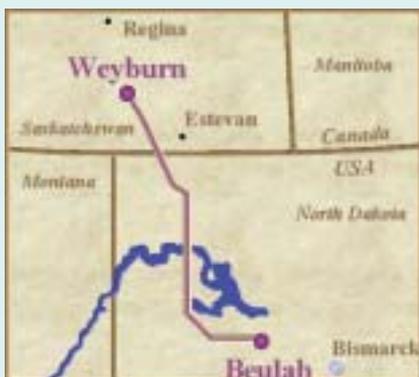
#### Canyon Reef Carriers (CRC) Pipeline and (planned) Centerline Pipeline

Constructed in 1972, the CRC Pipeline is the oldest CO<sub>2</sub> pipeline in West Texas. Now owned by Kinder Morgan, it extends 225km from McCamey, Texas, to Kinder Morgan's SACROC Field. The pipeline is 406mm (16") in diameter and has a capacity, following the completion of an expansion project in 2001, of approximately 8.2 million m<sup>3</sup>/day. In April 2002, Kinder Morgan announced an expansion of CO<sub>2</sub> supplies to SACROC with plans to build a new \$40 million Centerline Pipeline that will originate near Denver City, Texas, and transport CO<sub>2</sub> to the field. The pipeline will consist of 193km of 406mm (16") pipe. Construction is due to be completed in the third quarter of 2003 and is subject to standard permitting and regulatory approvals. The new pipeline will primarily supply the SACROC Unit, but will also be available for existing and prospective third-party CO<sub>2</sub> projects in the Horseshoe Atoll area of the Permian Basin. Existing projects include the Reinecke, Sharon Ridge and Cogdell Units. Oil production from SACROC has increased by approximately 50% since Kinder Morgan acquired an interest in SACROC and assumed operations in June of 2000, and it is evident that more CO<sub>2</sub> infrastructure is needed if SACROC is to achieve its maximum potential production levels. The planned additional infrastructure will increase CO<sub>2</sub> deliveries to the project from 3.54 million m<sup>3</sup>/day to well over 5.6 million m<sup>3</sup>/day when the expansion comes online in late 2003. Kinder Morgan expects CO<sub>2</sub> deliveries to SACROC to grow to approximately 9.2 million m<sup>3</sup>/day.

#### 6.2.2 The DGC-Weyburn CO<sub>2</sub> Pipeline

The CO<sub>2</sub> used in the Weyburn EOR operation in Saskatchewan is supplied from the Great Plains Synfuels Plant (GPSP), located some 13km north west of the town of Beulah in North Dakota. This plant is operated by the Dakota Gasification Company (DGC), a subsidiary of Basin Electric. The plant's prime activity (and reason for construction) is the manufacture of synthetic natural gas (SNG) derived from lignite supplied by the adjacent Freedom Mine. The GPSP has subsequently developed the production of a range of by-products, of which fertilizer has been the most important, with CO<sub>2</sub> being the most recent by-product to be marketed.

The DGC-Weyburn CO<sub>2</sub> Pipeline



In July 1997, a 15 year contract was signed between DGC and PanCanadian Petroleum Ltd (now EnCana Resources) to supply CO<sub>2</sub> to the Weyburn Field along a purpose-built 330km pipeline (some of the commercial aspects of this contract are described in Section 8.1.2). DGC allocated \$110 million to build the pipeline and compressor and expected to receive \$15-18 million in net annual revenue from PanCanadian. A subsidiary company, Souris Valley Pipeline Ltd, was formed to operate the 56km of pipeline crossing Canadian territory, with DGC operating the US portion of the pipeline. CO<sub>2</sub> has been delivered to the Weyburn Field since September 2000. The pipeline is constructed from carbon steel (API 5L) and has seamless welded joints, external corrosion proof coating and cathodic protection (see later). The pipeline is buried to a minimum depth of 1.5m and, along one section, it underlies a man-made lake. The pipeline is designed to cope with rapid temperature changes (-78.5°C) that could arise from depressurisation in the event of catastrophic failure. It has a diameter of 356mm (14") to Tioga in North Dakota (where a lateral spur could be fitted in the future if needed, i.e. to supply other EOR operations en route) and then 305mm (12") to Weyburn. The 305mm diameter section will handle in excess of 5,000 tonnes of CO<sub>2</sub> per day. There are no pumping stations en route.

The gas is delivered to the Weyburn Field at around 152 bar and can be injected at this pressure (minimum pressure to maintain CO<sub>2</sub> in its dense phase is around 103 bar). The compression is accomplished with a German (Borsig) built compressor that uses a single central gear to drive all the nine stages of compression. The compressed gas is cooled between each successive stage. This is apparently the largest compressor (two trains, each with a capacity of 2,500 tonnes per day of CO<sub>2</sub> compressed to 172 bar) of this type. It uses a single speed drive and central gear to run all stages. In the first year, the compressors had teething problems that resulted in lower than expected CO<sub>2</sub> deliveries, but these problems are now resolved.

The level of purity of the CO<sub>2</sub> supplied from the GPSP (96%+) is ideal for use in EOR. This is because 100% pure CO<sub>2</sub> is less effective as an EOR injectant than slightly impure CO<sub>2</sub> (CO<sub>2</sub> dissolves more readily into oil when small impurities are present). The presence of hydrogen sulphide (H<sub>2</sub>S) as an impurity – typically 2.5% - is also an advantage, as this particular gas further enhances the ability of the injected CO<sub>2</sub> to mix with the oil. Since Weyburn already contains H<sub>2</sub>S, introducing this gas into the oil reservoir presents no additional problems. One disadvantage of the syngas source of CO<sub>2</sub> is the presence of mercaptans. These sulphurous organic compounds have a strong odour and it only requires minute concentrations for the human nose to pick up the smell. (They are deliberately added to natural gas supplies for this reason so that leaks can be detected). The CO<sub>2</sub> supply to Weyburn typically comprises the following gases (% or ppm by volume): 96% CO<sub>2</sub>; 0.9% H<sub>2</sub>S; 0.7% methane (CH<sub>4</sub>); 2.3% C<sub>2</sub>+ hydrocarbons; 0.1% carbon monoxide (CO); <300 ppm nitrogen (N<sub>2</sub>); <50 ppm oxygen (O<sub>2</sub>); <20 ppm water (H<sub>2</sub>O).

### 6.2.3 CO<sub>2</sub> Pipeline Construction Costs

As a rule of thumb pipeline construction costs are approximately \$1.225 per millimetre diameter per kilometre length (approximately \$50k/inch mile).

### 6.2.4 CO<sub>2</sub> Cost/Price

The cost per tonne of CO<sub>2</sub> delivered to Kinder Morgan's SACROC Field in West Texas is currently approximately \$20/tonne.

In the case of EnCana's Weyburn Field, the CO<sub>2</sub> is purchased from DGC and governed by a long term (15 year) contract. The price per tonne of CO<sub>2</sub> is of the order of \$19/tonne and needs to allow for cost recovery of the pipeline construction (capital cost \$110 million), plus running, maintenance and compression costs. This price is likely to be the upper price limit due to potential competition from alternative CO<sub>2</sub> sources within Canada. The pipeline has extra capacity and sections designed in anticipation of joining new supply spurs to the main pipeline. If future CO<sub>2</sub> contracts are won from other oil field operators, then the net revenue for the remaining 8,000 tonnes/day CO<sub>2</sub> capacity could be greater than that derived from the contract with EnCana to supply CO<sub>2</sub>-EOR operations at the Weyburn Field.

### 6.2.5 Pipeline Regulation and Safety

In the USA, CO<sub>2</sub> pipeline operations are conducted under the regulation of the Office of Pipeline Safety in the U.S. Department of Transportation and are subject to the 1999 Code of Federal Regulations, Part 195 - "Transport of Hazardous Liquids". They are classified as "High Volatile/Low Hazard and Low Risk". At State level, authorities act as Certifying Agents, e.g. in Texas this includes the Texas Railroad Commission's Pipeline Safety Programme in the Oil & Gas Services Division. As CO<sub>2</sub>, in the presence of water, is corrosive to mild steel, it is a fundamental requirement to transport the CO<sub>2</sub> in a "dry" state, which makes it virtually inert. Another problem is that dense phase CO<sub>2</sub> is an excellent solvent (hence its use for EOR); this means that it can attack valve seals. Seal materials have now been perfected to high operational standards, however the experience of mercaptan odours as associated with the Weyburn Pipeline (see below), suggests that even modern valve seals are permeable to very small amounts of CO<sub>2</sub>, potentially adding to gas leakage along the valve stems. Notifiable leakages in CO<sub>2</sub> pipelines are rare (see table below) and comparable in frequency per kilometre of length to natural gas leaks. However, the impact of a CO<sub>2</sub> leak is likely to be much less hazardous than a natural gas leak, as CO<sub>2</sub> is not flammable or an explosive. CO<sub>2</sub> readily disperses in turbulent air. CO<sub>2</sub> is denser than air so with respect to open ground, it is only in situations where the air is stagnant and topography is such that CO<sub>2</sub> can pond where significant hazardous build-ups can occur. Although CO<sub>2</sub> is not explosive, the Mission team heard anecdotal information concerning an incident where an underground pipeline leak caused a build-up of CO<sub>2</sub> dry ice around the pipe that eventually failed causing violent depressurisation. The pipeline was repaired within 24 hours and no injuries were reported. One other incident has also occurred. In both cases leakage was due to external corrosion of the pipe.

#### Comparative Pipeline Incident Statistics, 1994-2000

(Source: Office of Pipeline Statistics/ US Department of Transportation)

Pipeline Content	Natural Gas	Hazardous gases	CO <sub>2</sub>
Incidents	510	1,220	5
Fatalities	21	16	0
Injuries	75	66	0
Damage	\$135m	\$370m	\$54,000
Incidents/1,000km/year	0.14	0.69	0.23

Kinder Morgan has an excellent safety record and follows many regulations and procedures to monitor and ensure the integrity of its pipelines:

- Pipeline operating conditions are monitored 24 hours a day, 7 days a week by personnel in control centres using a Supervisory Control and Data Acquisition (SCADA) computer system. This electronic surveillance system gathers such data as pipeline pressures, volume and flow rates and the status of pumping equipment and valves. Whenever operating conditions change, an alarm warns the operator on duty and the condition is investigated. Both automated and manual valves are strategically placed along the pipeline system to enable the pipeline to be shutdown immediately and sections to be isolated quickly, if necessary.
- Visual inspections of Kinder Morgan's pipeline right-of-way are conducted by air and/or ground on a regular basis. The right-of-way is a narrow strip of land reserved for the pipeline. Above ground marker signs are displayed along the right-of-way to alert the public and contractors to the existence of the pipeline.
- Internal inspections are conducted periodically by passing sophisticated computerised "smart pigs" through most pipelines to confirm the wall thickness of the pipe.
- Cathodic protection (a small electric current) is used to protect pipelines from external corrosion.
- Kinder Morgan's public education programme is designed to prevent third-party damage to its pipelines. Additionally, the company is a member of numerous "call-before-you-dig" programmes or "one-call" systems across the United States, which are designed to help the public, contractors and others identify the location of pipelines before excavation or digging projects to prevent damage to pipelines and protect the public. The leading cause of pipeline accidents is third-party damage caused by various types of digging and excavation activities.

Emergency preparedness and planning measures are in place at Kinder Morgan in the event that a pipeline incident occurs. The company also works closely with local emergency response organisations to educate them regarding CO<sub>2</sub> pipelines and how to respond in the unlikely event of an emergency.

Examples of procedures are as follows:

#### ***“What is a Pipeline Emergency?”***

- *A weakened or damaged pipeline*
- *Fire or explosion near or directly involving a pipeline or pipeline facility*
- *A natural disaster affecting the pipeline, such as an earthquake, flood or soil erosion*

#### ***A Leaking Pipeline***

*How to Recognize a Pipeline Leak When Near a Pipeline Right of Way*

*Listen for: Hissing or roaring sound*

*Look for: A white cloud, fog, or ice; dying plants amid healthy ones; unusual blowing of dirt or dust; persistent bubbles in water*

#### ***What to do in a Pipeline Emergency***

- *Immediately leave the area – on foot – in an upwind direction*
- *Avoid making contact with escaping liquids or vapors*
- *Abandon all equipment being used in the area*
- *DO NOT drive into an area in which you encounter a leak or vapor cloud*
- *Warn others to stay away from the area*
- *DO NOT try to operate any pipeline valves yourself*

*From a distant phone, call Kinder Morgan’s CO<sub>2</sub> Emergency number, 1-877-390-8640, and call 911 or your local fire, police, or sheriff’s office.”*

In Canada, CO<sub>2</sub> pipelines are regulated by the National Energy Board. The Mission team visited the DGC-Weyburn Pipeline at both the “source end” (DGC’s synfuels plant near Beulah, North Dakota), and at the “use end” (the Weyburn Field near Weyburn, Saskatchewan). While the US section of the pipeline is regulated under the Office of Pipeline Safety, as described above, the Canadian section of the pipeline is regulated under the National Energy Board as a Class 1 “Sour Service” Pipeline.

As in the case of the Kinder Morgan pipelines, the DGC-Weyburn pipeline is controlled by a SCADA computer system from Beulah. The control system monitors volumetric flow rate. Pressure control valves are set at 30km intervals; these valves comprise a pressure transducer, controller and valve operator and antenna. The control valves are automatically closed in event of pipeline failure. In November 2000, there was a valve leak emitting mecaptans near Tioga that necessitated the line being shut down for 17 days while fixing the problem.

DGC has taken the initiative to avoid dangerous leaks by using leak detection technology manufactured by Stoner. It tested leak detection accuracy and the precision of leak location identification for leaks ranging in size from a simulated pipeline rupture to a seepage-size leak.

Stoner’s system is integrated to a Honeywell Plantscape SCADA system, which monitors both the pipeline and the CO<sub>2</sub> compressor station. Based on data provided by the Stoner system, a Plantscape Leak Detection screen displays the detection of a leak, the estimated location, a location range in both miles and kilometers, and the leak size. In addition to leak detection capabilities, the Stoner system monitors pipeline instrumentation and identifies calibration or instrument drift problems.

### 6.3 Implications and Lessons for the UK

Experimental CO<sub>2</sub> floods were tried in the UK East Midlands oil fields during the 1960s by BP, but due to the high cost of obtaining CO<sub>2</sub> (from industrial sources) and the impracticality of trucking large quantities of CO<sub>2</sub>, the experiment was suspended. These barriers still exist today. Unlike the USA, where the large volumes of relatively cheap CO<sub>2</sub> necessary for EOR are abundantly available from natural accumulations (in the USA CO<sub>2</sub> prices have fallen as the infrastructure has matured), CO<sub>2</sub> is not available from natural accumulations in the UK. Supplies will necessarily have to be from industrial capture - a much more expensive route. Early, "low hanging fruit" supplies from industrial sources, i.e. where relatively pure streams of CO<sub>2</sub> are already generated (e.g. natural gas processing or in petrochemical and fertiliser plant) will not provide sufficient volumes for large scale or multiple CO<sub>2</sub>-EOR operations in large offshore fields. (Note: the recent DTI SHARP Report estimated that over 60 offshore fields could be suitable for CO<sub>2</sub>-EOR). Large scale or multiple operations will require CO<sub>2</sub> to be supplied by deliberate capture (e.g. from power plants, cement works, etc). However, until capture costs fall low enough to enable the industrial supplier to sell the CO<sub>2</sub> at a commercial rate, or there are statutory or fiscal mechanisms that demand that CO<sub>2</sub> be captured and transported to an underground repository, then it is unlikely that a large CO<sub>2</sub> market and infrastructure will emerge. Interestingly, in the USA, it was legislation encouraging the security of supply, not environmental legislation, which stimulated and continues to stimulate the CO<sub>2</sub> market and associated infrastructure.

In the UK, no CO<sub>2</sub> pipeline infrastructure currently exists. This will require significant investment to build, without immediate return (note that the DGC Weyburn pipeline is exempted from tax royalties). Main trunk pipelines could be built with spur junctions constructed in anticipation of taking lateral lines (as was the case with the DGC-Weyburn pipeline). It may be possible to adapt some of the existing pipeline infrastructure to carry CO<sub>2</sub> instead of natural gas, but it is more likely that new pipelines would have to be laid. Some operational cost savings could be achieved if pipeline routing was combined with existing pipelines.

UK pipelines are more likely to be in proximity to buildings than in the USA (the DGC-Weyburn pipeline is routed with more than 400m clearance of buildings). It may be desirable to have closer spacing of monitoring devices and closure valves. Unlike North America, natural gas pipelines are common in the UK, supplying domestic, public and industrial premises. Natural gas pipelines are accepted by the public, despite deaths almost annually from explosions. Prior to the 1970s, town gas was similarly supplied. This contained highly toxic CO and H<sub>2</sub>S, which can also be found in industrially supplied CO<sub>2</sub> (cf. DGC's CO<sub>2</sub> supply). These factors suggest that public acceptance of CO<sub>2</sub> pipelines should be achievable. Mectaptans could be an issue with respect to industrially supplied CO<sub>2</sub>, especially with that supplied from pre-combustion capture (e.g. gasification). Problems of mectaptan leaks through valve seals associated with the DGC-Weyburn pipeline seem to have been resolved. Whilst leaks occurred, complaints were received from over 90km radius. Similar releases of mectaptans in the UK, though non-hazardous, could become a significant public nuisance if recurrent.

Supplying CO<sub>2</sub> to marine operations adds another corrosion issue not faced by onshore trunk pipelines in North America, where all CO<sub>2</sub> pipelines and EOR operations are onshore. However, pipeline coating technologies to prevent marine corrosion are already developed for North Sea pipelines. Kinder Morgan's view is that marine corrosion is a bigger risk than CO<sub>2</sub>/H<sub>2</sub>S corrosion with respect to potential CO<sub>2</sub> pipelines in the North Sea.



## 7 Geological storage

During the Mission, discussions were held with a number of organisations regarding the activities underway in the USA and (particularly) Canada to understand the science, engineering and long-term viability of CO<sub>2</sub> storage in geological structures. Much of this discussion concerned the International Weyburn CO<sub>2</sub> Monitoring and Storage Project, currently underway in conjunction with the commercial CO<sub>2</sub>-EOR activity at the Weyburn Field in Saskatchewan. Meetings were held with **BP**, the **US DOE**, **EnCana Resources** (Weyburn Field Unit), the **Petroleum Technology Research Centre (PTRC)** at the University of Regina, the **Alberta Research Council** and the **Canadian Environment Research Institute (CERI)**.

### 7.1 Background to the Technology

In order to achieve the dramatic reductions in CO<sub>2</sub> emissions required to stabilise the atmosphere at its current raised level of 375ppm by volume, global emissions will have to be reduced by over 60% by 2050 (see Section 1). A level of 550ppm is thought to be dangerous, not only due to the increased risk of climate change, but also because at that level several important marine organisms are harmed. To restore the atmosphere to its pre-industrial concentrations of around 280ppm, zero emission or even negative emission strategies would be required. Capturing CO<sub>2</sub> from fossil fuel use, especially high volume point source installations (e.g. power plants, petrochemical facilities and cement works) and then injecting it into suitable geological structures, could provide a significant contribution to emission reduction. This is especially so when energy projections for the next fifty years show that fossil fuels will remain the dominant source of energy.

Clearly, large CO<sub>2</sub> accumulations trapped naturally in geological structures exist (e.g. the McElmo and Bravo Domes – see Section 6.2.1), where the CO<sub>2</sub> has remained for tens of thousands to millions of years. Geological storage of CO<sub>2</sub> serves to mimic these natural examples. Underground storage strategies include trapping free gas in a geological structure or reacting/absorbing the CO<sub>2</sub> onto minerals. The majority of these strategies involve injecting CO<sub>2</sub> in its dense phase into the subsurface. Because injecting CO<sub>2</sub> into hydrocarbon fields and coal beds can result in enhanced production of hydrocarbons, this provides an early cost effective route to geological storage. In these “commercial” examples, the storage of CO<sub>2</sub> is not the central requirement but a useful by-product of a commercial operation. The largest potential for geological storage is in deep saline aquifers (below about 700m), however, until society is prepared to place an appropriate value on dedicated CO<sub>2</sub> capture and storage, this potential is unlikely to be realised.

The remainder of this section focuses on demonstration projects currently being undertaken or at a mature stage of planning.

### 7.2 Operational and Practical Issues

#### 7.2.1 The International Weyburn CO<sub>2</sub> Monitoring and Storage Project

EnCana’s oil field at Weyburn has been producing oil for almost 50 years and CO<sub>2</sub>-EOR operations commenced in 2000 with the aim of producing an incremental 130 million barrels of oil and extending the field’s life by around 25 years. It is also anticipated that some 20 million tonnes of CO<sub>2</sub> will be injected and become permanently stored underground over the lifetime of this project. This commercial “tertiary production” phase is described more fully in Section 8.1.2.2, but extensive research activities, under the “International Weyburn CO<sub>2</sub> Monitoring and Storage Project” have commenced to study the fate and security of the CO<sub>2</sub> once it is injected deep underground. These activities will help the understanding of the suitability of underground storage as a viable technique for large-scale reduction in CO<sub>2</sub> emissions to the atmosphere.

The Weyburn CO<sub>2</sub>-EOR operation represented an excellent site at which to undertake extensive research since there are probably only a few fields in the world that have such a detailed database of production and injection information, geophysical logs and over 600 cores accessible. Furthermore, it was possible to collect a full suite of baseline data before CO<sub>2</sub> injection began. In this way, it is possible to compare all monitoring results back against a clear baseline. One final point is that both EnCana and the Provincial Government of Saskatchewan are co-operative partners in the venture.

### 7.2.1.1 Project History

The International Weyburn CO<sub>2</sub> Monitoring and Storage Project began as a result of a workshop on sequestration hosted by the Petroleum Technology Research Centre (PTRC) of the University of Regina in August 1999. As a result of the international interest in undertaking a research programme at the Weyburn site, a research consortium consisting of public- and private-sector research agencies from Canada, the United States and Europe was established and funding requests made to various governments and their agencies and industry partners early in 2000.

In July 2000, a four year research project to study geo-sequestration and storage of CO<sub>2</sub> was launched by PTRC in close co-operation with EnCana of Calgary, Alberta. The project is now sponsored by a number of governments and industrial sponsors from North America, Europe (including the DTI) and Japan and has a cash budget of over C\$20million, with a similar value of “in-kind” contributions, particularly from EnCana. The project serves to answer several key questions:

- Is sequestration acceptable to the public and regulatory agencies?
- Can sequestration into geological formations offer long-term permanent storage for CO<sub>2</sub>?
- How much CO<sub>2</sub> can actually be stored and verified?
- What are the economic drivers?
- What are the risks associated with the sequestration option?
- Which technologies will be needed for monitoring and verifying the integrity of CO<sub>2</sub> sequestration?

The big question in the minds of the public and regulators is the integrity of storage. To help conduct a risk analysis, “FEP” (features, events and processes) methodology, adapted from experience in the nuclear industry, has been applied to Weyburn. This approach draws information from all existing data and information outputs from new research and field operations. FEPs are applied as follows:

- Features
  - an object, structure, or condition that has the potential to affect the storage system performance.
- Events
  - a natural or man-made phenomenon that has the potential to affect storage system performance, and that occurs during a relatively short time interval.
- Processes
  - a natural or man-made phenomena that has the potential to affect the storage system performance, which operates throughout the entire performance period.

This analysis takes into account all possible future scenarios for the area, be they naturally or anthropogenically induced. It will then set the level of risks associated with these events. For example, what is the risk of an earthquake damaging the cap rock or what would the effect be of mining operations passing through the reservoir to the underlying potash deposits? What are the risks to humans if a city is developed over the oil field in the future?

The project is divided into a number of tasks defined as follows<sup>26</sup>:

**Task 1: Field Support and Co-ordination** includes the support for and co-ordination of all the field activities and is led by EnCana Resources. This task includes the field supervision of monitoring crews, the acquisition of field performance data such as production and injection data, as well as specific research tasks carried out by EnCana such as groundwater sampling and analyses, tracer studies and four-dimensional, three-component (4-D, 3-C) surface seismic surveys.

**Task 2: Geo-science Framework** incorporates seven sub-tasks involved in different aspects of the geology and is led by Saskatchewan Industry and Resources. These investigations combine fresh reprocessing and interpretations of existing two-dimensional seismic surveys, well logs, core information as well as comprehensive hydrogeological studies on the direction and approximate rate of natural brine movement within the Mississippian aquifers and aquitards. Detailed shallow hydrogeological mapping is also carried out for the immediate area of Weyburn, as well as on a regional basis.

<sup>26</sup> Moberg, R. et al. 2002: The IEA Weyburn CO<sub>2</sub> Monitoring & Storage Project. Sixth International Conference on Greenhouse Gas Control Technologies (GHGT-6), Kyoto, Japan, 1-4th October 2002

**Task 3: Geochemical Sampling, Monitoring and Prediction** consists of a thorough investigation and modelling of the short- and long-term impact of the CO<sub>2</sub> on the reservoir rock and fluids and is led by Alberta Research Council. Baseline reservoir fluid, reservoir mineral and injection fluid compositions, and input and output flows have been determined both from historical data and chemical analyses prior to CO<sub>2</sub> flooding for the Phase 1a CO<sub>2</sub>-EOR area of the Weyburn field. At regular intervals during CO<sub>2</sub> flooding of the Weyburn reservoir, suites of water and gas samples are collected from producing wells and analysed. Preliminary analyses indicate that there is evidence of carbonate dissolution. The observed spatial distribution patterns for each element and isotope are similar between pre- and post-CO<sub>2</sub> injection but significant short-term temporal changes in them have been observed before adjusting back to the pre-injection pattern. The results of these analyses will be used in the long-term prediction of chemical reactions. A special task has been set up to develop the framework for and conduct a performance assessment of the sealing system(s) of the Weyburn oil reservoir. This includes examining possible leakage paths through the cap rock and well bores.

**Task 4: Monitoring CO<sub>2</sub> Movement** consists of a series of comprehensive high resolution time-lapse seismic monitoring surveys designed to determine the dynamic response of the reservoir to injection of CO<sub>2</sub> and is jointly led by Lawrence Berkeley National Laboratories and the Colorado School of Mines. This also includes seismic surveys carried out by EnCana as part of their miscible flood monitoring programme. A suite of baseline and repeat surveys such as subsurface horizontal cross-well and vertical seismic profiling and surface nine-component and three-component seismic surveys have been successfully completed during the Autumn of 2000 and 2001: While the Mission team was at the Weyburn site in November 2002, a third survey was being conducted. Early results from the interpretations of the seismic surveys are very encouraging. The next challenge is to fully integrate the results of these seismic surveys and to convert the processed data to yield engineering type parameters such as effective porosity, fluid saturations and permeability that can then be input into the numerical modelling for the reservoir.

*Seismic Source  
Truck  
Conducting  
Multi-component  
Seismic Survey,  
November 2002*



**Task 5: Storage Performance** is led by PTRC and includes collection and analyses of fluid samples to determine changes in composition during the four year period, short-term numerical simulations of several patterns within Phase 1a of EnCana's EOR project that will then be scaled up to the full 75 patterns and long-term modelling and risk assessment. The most difficult part of this research project will be to incorporate all the research findings of the other research providers into the final long-term modelling and risk assessment. Monitor Scientific, the research provider with expertise in risk assessment for nuclear waste disposal, will "reverse engineer" data flows to ensure that the right data from other research providers will be provided at the right time. A number of escape scenarios must be analysed too as part of the risk assessment.

**Task 6: Storage Economics** is led by the Alberta Research Council and involves the development of a CO<sub>2</sub>-EOR/storage economic model to assess the economics of CO<sub>2</sub> storage pre- & post-EOR operations. This model will be used to assess different injection and production strategies and their impact on oil production and CO<sub>2</sub> storage.

### 7.2.2 Enhanced Coalbed Methane (ECBM) in Alberta

This international demonstration project, led by the Alberta Research Council, is investigating the commercial viability of ECBM production applied to low permeability coal beds by injection of CO<sub>2</sub>-rich waste streams and the associated CO<sub>2</sub> sequestration potential.

More details of the work programme are given in Section 8.2.2.

### 7.2.3 Canadian Energy Research Institute (CERI), Calgary

In 2002, CERI completed a study of Canada's underground storage potential. The study focused on the Western Canada Sedimentary Basin (WCSB) and undertook uniquely detailed assessments of individual CO<sub>2</sub> sources and potential storage reservoirs. The study calculated potential storage capacities in the WCSB for hydrocarbon fields, coal beds and saline aquifers. It has screened the best opportunities and included economic analysis of various storage and CO<sub>2</sub> capture scenarios, providing a useful pointer to suitable demonstration sites in the WCSB.

### 7.2.4 Acid Gas Injection Monitoring

At the end of 2001, there were 31 sites in Alberta where acid gas was re-injected into depleted oil and gas reservoirs and deep saline aquifers primarily as a safe method of disposal of waste H<sub>2</sub>S streams. The composition of the re-injected gas varies from 20% CO<sub>2</sub> and 80% H<sub>2</sub>S to 95% CO<sub>2</sub> and 5% H<sub>2</sub>S. Acid gas injection operations in Alberta represent an analogue for geological sequestration of CO<sub>2</sub> and an opportunity to learn about the operational safety of these activities. Understanding the fate of the injected gases is an important opportunity to investigate the feasibility of CO<sub>2</sub> geological storage. The Alberta Geological Survey (AGS) of the Alberta Energy and Utilities Board (AEUB) and the Alberta Research Council (ARC) are jointly carrying out a project to review the information submitted by operators to AEUB in the process of obtaining approval for and running these 31 acid gas injection operations. AGS is reviewing the subsurface characteristics and ARC is reviewing the surface facility characteristics of these operations. One of these sites will be selected and undergo a comprehensive due diligence study to establish the viability and importance of this technology for creating GHG emission credits when a trading market is firmly established.

## 7.3 Implications and Lessons for the UK

The UK is actively involved in the International Weyburn CO<sub>2</sub> Monitoring and Storage Project - the British Geological Survey, supported by DTI, leads the EU research team which is involved in several of the tasks listed above. The research outputs from the Weyburn research project will be invaluable, as no CO<sub>2</sub>-EOR operations are being conducted in Western Europe. What is needed to supplement the Weyburn activities is more knowledge about CO<sub>2</sub> floods in clastic reservoirs (the most likely scenario in UK applications) and how a CO<sub>2</sub> flood can be optimised in an offshore setting, where well spacing will be wider and injectivity patterns different.

The Cabinet Office's PIU Energy Review (referred to in Section 1) recommended that the DTI makes a decision on whether to support a programme for CO<sub>2</sub> capture and storage. The Mission team believe that a demonstration project on underground CO<sub>2</sub> storage is needed in the UK to build confidence in the technology. It would be vital to undertake extensive research activities into the fate of CO<sub>2</sub> injected during any such demonstration activity, and the security of the storage (i.e. is the CO<sub>2</sub> likely to be stored for time periods of the order of 1,000 years or more?).

The Alberta ECBM demonstration project, which addresses CO<sub>2</sub> sequestration onto low permeability coals, is of direct relevance to the UK since permeability is one of the greatest concerns for CBM, and therefore ECBM success in the UK.

The acceptance of acid gas injection into Canadian depleted oil fields and deep saline aquifers provides an important analogue for dedicated CO<sub>2</sub> storage options in the UK; particularly with respect to low purity streams of CO<sub>2</sub> (which could reduce capture costs), safety and regulation.

## 8 Carbon dioxide use

Sequestration of CO<sub>2</sub> within geological formations, such as those associated with depleted oil and gas fields, saline aquifers and coal measures (as described in Section 7.1), will only be undertaken for environmental reasons (i.e. climate change amelioration). However, certain properties of CO<sub>2</sub> make its use as a “working fluid” possible and opens up potential opportunities for revenue generation.

The first such use of CO<sub>2</sub> is for enhanced oil recovery (EOR) from depleting oilfields. In this case, the ability of CO<sub>2</sub> to penetrate rock pores to reach stranded oil, act as a solvent and “swell” the residual oil and sweep it from the matrix of the oil-bearing strata, makes CO<sub>2</sub> a potentially attractive injectant into depleting fields to provide “tertiary production” (i.e. usually after water flooding has been used for secondary production). This use – CO<sub>2</sub>-EOR, or “CO<sub>2</sub> flooding” – has been deployed in North America for over 30 years.

Another potential use of CO<sub>2</sub> within a geological structure is for enhanced coal bed methane (ECBM) production. This potential use is only in the early stages of development but uses injected CO<sub>2</sub> to displace coal bed methane (CBM) and increase its production. Clearly, whereas CBM extraction may precede mining of the coal itself, ECBM production would only be an option for unmineable coal seams.

Although not currently being practised in North America, enhanced gas recovery (EGR) using CO<sub>2</sub> injection is being considered for deployment elsewhere in the world. BP discussed its proposed CO<sub>2</sub>-EGR project in Algeria with the Mission team. This technology is not discussed further in this report as it is not being developed, demonstrated or deployed in North America, however, it should be noted that it might have possible applications in the North Sea.

Since depleting oilfields and unmineable coal seams represent two significant potential “sinks” for CO<sub>2</sub> in the UK, the possibilities of CO<sub>2</sub>-EOR and CO<sub>2</sub>-ECBM providing a revenue stream to partially (or in some cases elsewhere in the world, fully) offset the costs of CO<sub>2</sub> capture, transportation and sequestration, may be of considerable interest.

This section of the report examines the CO<sub>2</sub>-EOR and CO<sub>2</sub>-ECBM activities being undertaken in the USA and Canada, and their potential application in the UK.

### 8.1 CO<sub>2</sub> Use for Enhanced Oil Recovery

During the course of the Mission, site visits were made to two producing oilfields using CO<sub>2</sub>-EOR (or “CO<sub>2</sub> flooding” as it is more commonly known in North America). The first was the SACROC oilfield near Snyder in the Permian Basin of West Texas, USA, now operated by **Kinder Morgan CO<sub>2</sub> Company L.P.** The second was the Weyburn oilfield near Weyburn in the Williston Basin in the southern part of the Province of Saskatchewan, Canada, operated by **EnCana Resources** (formerly PanCanadian Petroleum Ltd).

Several other meetings during the course of the Mission covered aspects of CO<sub>2</sub>-EOR including **NATCO Group** in Houston, **BP** and the **US DOE** in Washington, DC. Discussions were also had with various organisations involved in different aspects of EnCana’s Weyburn operation, particularly the **International Test Centre (ITC) for CO<sub>2</sub> Capture**, the **Petroleum Technology Research Centre (PTRC)**, both based at the University of Regina, the **Alberta Research Council** in Edmonton, Alberta and **CANMET Energy Technology Centre (CETC) – Devon** in Alberta and **CETC – Ottawa** in Ontario (both part of Natural Resources Canada). More general discussions concerning the economics of CO<sub>2</sub>-EOR were also had with the **Canadian Energy Research Institute (CERI)** in Calgary, Alberta.

#### 8.1.1 Background to the Technology

While the usage and definition of the term enhanced oil recovery varies, it is generally used to describe the process of injecting either a liquid or gas into a reservoir to scrub out oil remaining after pumping (“primary production”) is no longer economically productive. Primary production (also referred to as “primary depletion”) uses natural producing processes such as liquid expansion and solution gas drive, but generally leaves behind more than 80% of the original oil in place (OOIP).

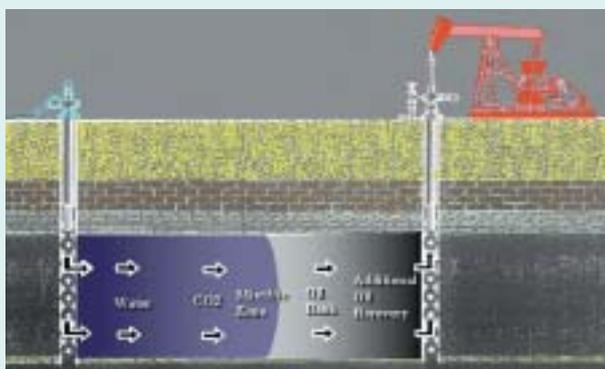
The most common EOR technique is “water flooding” (or “secondary production”), which involves pumping water into the oil reservoir to increase pressure and boost production. Use of this technique, discovered accidentally in 1880, expanded rapidly from the 1920s and is still extensively used. Even after secondary production, often as much as 80% OOIP remains in the oil-bearing strata.

“Tertiary production” uses gas injection processes. CO<sub>2</sub> injection has become the leading EOR process in the US, adding decades to the life of reservoirs believed to be depleted and millions of barrels of oil to the world supply. In 2000, gas injection (mostly CO<sub>2</sub>) accounted for about 44% – 328,000 barrels of oil per day (BOPD) – of the total US EOR production. In Canada, the emphasis is on hydrocarbon gas injection, with 29 such projects and only two CO<sub>2</sub> floods. In the Gulf of Mexico, a nitrogen injection EOR project is operating.

In CO<sub>2</sub>-EOR, the CO<sub>2</sub>, which is miscible with oil, penetrates small pore structures in the oil-bearing strata to contact stranded, immobile, residual oil. At certain pressures (i.e. above the minimum miscibility pressure – usually requiring a depth of at least 750m) the CO<sub>2</sub> and the oil mix, with the CO<sub>2</sub> acting as a solvent to overcome the forces that trap the oil in the rock pores. The CO<sub>2</sub> effectively dissolves into the oil, causing the oil to swell in volume and reduce in viscosity – both effects helping it to move through the strata. The CO<sub>2</sub> dissolves more readily into the lighter oil fractions, this results in production of a lighter crude than the virgin one, which is also richer in volatiles and hydrocarbon gases. In carbonate reservoirs, the CO<sub>2</sub> also partly dissolves the rock, improving its permeability, which in turn releases oil and aids its movement to the production wells. When the pressure in the reservoir rises, the injected CO<sub>2</sub> creates a “bank” of oil that is driven to the producing wells in the oil field where, due to its reduced viscosity, it is easier to pump to surface. In this way, the CO<sub>2</sub> sweeps the immobile, medium weight oil that has been left behind after water flooding.

To increase the effectiveness of CO<sub>2</sub>-EOR tertiary production, sequential injection of CO<sub>2</sub> followed by water – so called “water-alternating-gas (WAG)” patterns – are used to drive the oil banks to the wells. This is illustrated in the diagram below:

CO<sub>2</sub>-EOR  
with Water-  
Alternating-  
Gas (WAG)  
Pattern



Although not practised in North America, an alternative to WAG is “gravity stabilised gas injection (GSGI)”. In this technique, the injectant is pumped into the top of the depleting reservoir, displacing hydrocarbons downwards to the bottom of the reservoir. GSGI can lead to the recovery of more residual oil, and could probably lead to more CO<sub>2</sub> being sequestered, while needing fewer wells. However, the “breakthrough periods” (i.e. the time delay between injecting CO<sub>2</sub> and producing CO<sub>2</sub> with additional oil at producer wells) would likely be considerably longer, with consequential effects on cashflow. Since GSGI is not practised in North America, it is not covered by this report, although it should be noted that it might be an attractive alternative to WAG in any future CO<sub>2</sub>-EOR operation in the North Sea due to the need for fewer wells.

In 1972, the USA was the first country to use miscible “CO<sub>2</sub> flooding” (i.e. CO<sub>2</sub>-EOR) for tertiary oil production: This first commercial application took place at the SACROC oil field in the Permian Basin of West Texas. Throughout the 1980s, many operators established CO<sub>2</sub> flood projects in other US States, Canada, Turkey, Trinidad and Hungary, but the majority of activity remains in the West Texan Permian Basin with 47 such projects currently active, representing around half of the CO<sub>2</sub> floods world-wide and accounting for more than 20% of the area’s oil production. During 2002, the billionth barrel of CO<sub>2</sub>-EOR oil was produced in the Permian Basin and the production of 175,000 barrels of oil per day (BOPD) is attributable to CO<sub>2</sub>-EOR (in the USA as a whole, this figure rises to 200,000 BOPD).

Almost all the CO<sub>2</sub> used in the Permian Basin floods comes from natural sources in Colorado and New Mexico via a 1,600km network of pipelines. This experience of piping pressurised (dry) CO<sub>2</sub>, plus the experience of injecting into depleting oilfields using “WAG” patterns, pumping oil and CO<sub>2</sub> from producing wells and separating CO<sub>2</sub> from the hydrocarbon and recycling to injection wells for, in the case of SACROC, 30 years, has led to world leading technology developments with applicability to the UK context.

### 8.1.2 Operational and Practical Issues

There are many similarities and some key differences between the two operations visited as part of this Mission. For this reason, they are examined separately below but in such a way that the similarities and differences are clear.

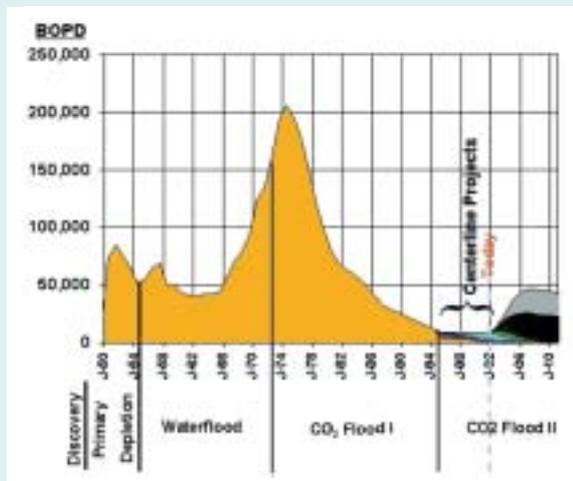
#### Kinder Morgan’s SACROC CO<sub>2</sub>-EOR Operation, West Texas

##### History

The Kelly-Snyder oil field was discovered in 1948 with an estimated 2.8 billion barrels of original oil in place (bbl OOIP), making it the seventh largest oilfield in North America. Primary production/depletion (gas expansion drive with minor water influx) occurred between 1948 and 1954. During this period, production was limited by Government “Well Allowances” and peaked at 112,000 BOPD in November 1950. Water “cut” (i.e. percentage of water in the well production fluids) rose from zero to around 9% over this period.

The field was later utilised in 1954 as the “SACROC” (Scurry Area Canyon Reef Operators Committee) unit. After utilisation, secondary (“waterflood”) production commenced in 1954 and continued until early 1972. Production was still controlled by Government allowances, based on “field” output by this stage, reaching 150,000 BOPD. By this stage, the water cut had risen to around 27%.

SACROC  
Development  
History  
(courtesy of  
Kinder Morgan  
CO<sub>2</sub> Company L.P.)



From the early 1970s, a favourable tax regime encouraged oil operators to undertake tertiary production on depleting oilfields. This environment continues today with a complex mixture of five or six National/State tax credit schemes. Overall, these schemes equate to roughly a 50% reduction in tax on a barrel of oil produced. This, understandably, led to a thriving tertiary recovery business, with SACROC leading the way. Further information on fiscal measures for encouraging CO<sub>2</sub>-EOR is included in Section 9.4.1.

In 1972, tertiary production using CO<sub>2</sub> injection commenced at SACROC. With relatively low CO<sub>2</sub> injection rates of 4.25-5.0 million normal m<sup>3</sup>/day, oil production continued to rise so that by the time production allowances were removed in 1974, production reached its peak of 211,000 BOPD. Production rates could probably have been much higher if the operators had had a greater understanding of minimum miscibility pressure (i.e. to keep the CO<sub>2</sub> dissolved in the oil) and the geology. From this time, production declined steadily until, by early 1995, production had fallen to 10,000 BOPD with a water cut of 97%. CO<sub>2</sub> injection rates had likewise fallen to 1.4Nm<sup>3</sup>/d and it appeared that SACROC’s life was drawing to an end having produced over 1.2 billion barrels of oil from some 1,700 wells.

In 2000, Kinder Morgan purchased that part of SACROC that had been owned and operated by Devon Energy and set about a second phase of CO<sub>2</sub>-EOR based around higher CO<sub>2</sub> injection rates and better miscible flooding (compared to suspected immiscible flooding previously). It focused attention on developing an optimised pattern of CO<sub>2</sub>/water injector wells, water injector wells and producer wells in a small area around the centre-line of the field. Kinder Morgan also purchased from Shell CO<sub>2</sub>, their naturally occurring CO<sub>2</sub> reserves at McElmo Dome in Colorado (0.4 trillion m<sup>3</sup> reserves or around 100 years worth of high pressure, 98%+ purity CO<sub>2</sub>) and 1,600km of pipeline linking this to SACROC and other fields (see Section 6.2.1).

#### Current Operations at SACROC

The Canyon Reef oil-bearing strata is a complex Pennsylvanian age (equivalent in age to some of the upper Carboniferous, coal measures of the UK) carbonate reef system. It is discontinuous and heterogeneous, with lateral and vertical discontinuities, detrital flows, karsting, high and low permeability areas, micro fractures and short distance changes in porosity. The reef undulates, with a depth varying from 1,920m to 2,070m (average depth is 2,040m) and the average thickness of the reef is 80m. Porosity varies from <5% to >20% (averages 7.6%) with an average permeability of 19.4mD. The 21,000ha SACROC field extends to approximately 25km by 13km.

As described in Section 6.2.1, the majority of the CO<sub>2</sub> used for CO<sub>2</sub> floods in West Texas is supplied by Kinder Morgan CO<sub>2</sub> Company from its McElmo Dome natural source in southern Colorado. The CO<sub>2</sub> for SACROC is transported to the oil field via the Canyon Reef Carrier (CRC) Pipeline as “dry” (<0.5gH<sub>2</sub>O/Nm<sup>3</sup>CO<sub>2</sub>), dense phase, supercritical fluid, effectively eliminating corrosion (see later note).

This natural and “sweet” (98%+ pure) CO<sub>2</sub> is supplemented by 5 million tonnes/year of CO<sub>2</sub> captured from four natural gas processing plants owned by Associated Gas using amine scrubbing. This CO<sub>2</sub> is relatively “sour”, with around 2,000ppm of H<sub>2</sub>S in it, and is at a low pressure (~0.35 bar). This captured CO<sub>2</sub> (which forms a part of the recent large CO<sub>2</sub> emission trading deal with Ontario Power Generation and CO<sub>2</sub>e.com) typically forms between 5% and 10% of the 6.7 million Nm<sup>3</sup>/day of CO<sub>2</sub> passing through the CRC Pipeline to SACROC.

On arrival at the gas processing complex at SACROC, the dense phase CO<sub>2</sub> from the CRC pipeline (at about 100 bar) is combined, as necessary, with the CO<sub>2</sub> recovered from the oil field product (at about 75 bar) to make up the required flow for re-injection and is pumped through a 2,240kW, 8.5 million m<sup>3</sup>/day pump to an injection pressure of 138 bar. This is then distributed by pipeline to the injector wells.

Of the approximately 1,700 wells that have been drilled over the years at SACROC, Kinder Morgan currently has 410 wells (200 injector wells and 210 producer wells) in operation for this tertiary stage of production. The long-term aim is to increase this to 1,000 operational wells. It is expected that some 800 will be operational by August 2003, requiring a new CO<sub>2</sub> supply pipeline (the proposed Centerline Pipeline – see Section 6.2.1) to be built from Denver City to SACROC during 2003.

Wells at SACROC are vertical, giving access to the several oil-bearing zones that comprise the complex reef structure.

The 200 injector wells inject around 5.1 million Nm<sup>3</sup>/day (about 9,450t/day) of CO<sub>2</sub> and 31,800m<sup>3</sup>/day of water in WAG patterns that mean changing injectant every few days. A number of the injector wells only inject water; this is used towards the edge of the producing area to create a “water curtain” to contain the CO<sub>2</sub>.

The injector well arrangement is shown in the photograph on the opposite page. The water supply pipe (right) is joined by the CO<sub>2</sub> supply pipe (coming in from the side) before passing through a turbine meter (good for metering dense phase CO<sub>2</sub>) and a choke valve to the well “christmas tree”. Although the injector wells are currently manually controlled, it is intended to automate them and effect control from the control centre.

*CO<sub>2</sub>/Water  
Injector Well  
at SACROC*



Well spacing is approximately 200m, with the wells generally arranged in a “5-spot” grid pattern (i.e. four wells in a square with a well in the centre).

The WAG pattern is carefully managed by a reservoir management team at SACROC. On the one hand, large “slugs” of CO<sub>2</sub> to create banks of oil travelling to the producer wells are desirable. On the other hand, too much CO<sub>2</sub> injection can create gas production control problems, plus CO<sub>2</sub> can be ten times as expensive to inject as water. A CO<sub>2</sub> flood is more complicated than a waterflood and the reservoir management engineers need to carefully determine how much CO<sub>2</sub> to inject, how fast to inject it, and when to switch to water injection. At the present time, the water injection as a proportion of hydrocarbon pore volume is around 15% generally, although it is intended to increase this to around 60%. As the distance increases between injection point and producer well, there is a tendency to see a “plateauing” of CO<sub>2</sub> production (and hence oil production); in these situations, the water injection phases of the WAG pattern are generally extended (or initiated earlier) so as to push the oil bank more cost effectively towards the producer wells. This is colloquially referred to at SACROC as “wetting the WAG”!

CO<sub>2</sub> and water pressures are important in the WAG cycle – both currently 138 bar. Work undertaken by ChevronTexaco has looked at any effect that high injection pressure might have on the strata matrix. Up to 400 pore volumes of CO<sub>2</sub> was put into a rock matrix with no discernable effects on matrix integrity.

“Breakthrough” periods at SACROC are generally 3-6 months, although delays of 2-3 years have been experienced on other West Texas oil fields.

Approximately one third of the CO<sub>2</sub> injected remains in the strata. Clearly, Kinder Morgan wish to minimise the loss of this valuable working fluid: If CO<sub>2</sub> storage was also an objective at SACROC (rather than it being a purely commercial EOR operation), then this would be viewed somewhat differently.

The current 210 producer wells produce around 15,000 BOPD, 2.7 million Nm<sup>3</sup>/day of gases (CO<sub>2</sub> and hydrocarbon gas) and 26,250m<sup>3</sup>/day of water. The production of all these is steadily increasing as the CO<sub>2</sub>-EOR matures.

Although corrosion due to the CO<sub>2</sub> is not a problem prior to injection (due to the CO<sub>2</sub> stream being “dry”, i.e. <0.5gH<sub>2</sub>O/Nm<sup>3</sup>CO<sub>2</sub>), at the producer well, corrosion becomes a major issue. When CO<sub>2</sub> dissolves in water, a small fraction hydrolyses to form carbonic acid while the remainder exists as physically dissolved CO<sub>2</sub>. Carbonic acid dissociates to form bicarbonate ions and hydrogen ions and is quite corrosive to most carbon steels. The casing and tubing that form the annular producer well are therefore liable to corrosion. To counteract this, the tubing is lined with polyethylene (very tough, ductile and resistant to acids and solvents) and the annulus between the casing and the tubing is filled with inhibitor fluid. This has reduced corrosion to less than 2.5µm/year. The surface structure of the producer wells are made of carbon steel but lined with an epoxy plastic or fibreglass coating (standard oil industry practice). It has been found that the presence of H<sub>2</sub>S tends to combat carbonic acid problems associated with CO<sub>2</sub> injection by forming a protective iron sulphide scale on carbon steel: However, this effect provides limited protection since the H<sub>2</sub>S itself affects the metallurgy and causes corrosion.

At SACROC, the fluids (i.e. oil and water) are pumped to the surface by submersible pumps at the bottom of the producer wells. These pumps are fitted with rotary gas separators – the gases are not pumped but rather allowed to expand up the casing/tubing annulus and are then recombined with the pumped fluids at the well head at a pressure of 52 bar. The producer well arrangement is shown below.

*Producer Well  
at SACROC*



The product from the 210 producer wells is pumped to one of eight separator tank batteries (this will increase to 20 as the number of wells is increased) where the lined well pipes are combined in header manifolds – made of 316 stainless steel (these items are hard to line). The residence time in the lined, three phase separator tanks is sufficient to separate the oil, water and gases. The oil is fed to automated pump stations for onward transfer. The water goes directly to central water treatment plants to “de-energise” the water (i.e. release dissolved CO<sub>2</sub>). This is done in 1,600m<sup>3</sup> multi-stage, epoxy lined tanks fitted with skimmers to recover any carry-over oil. Centrifugal water pumps return the water at 138 bar to the network feeding the injector wells. The gases (CO<sub>2</sub> and hydrocarbons) are collected from the three phase separators and are pumped at 14 bar to the gas processing complex. It is important to manage the cut of CO<sub>2</sub> in the product gas stream (i.e. to keep the CO<sub>2</sub> as low as possible). Infra red CO<sub>2</sub> analysers are located at the eight separator tank batteries and if the CO<sub>2</sub> cut goes above 85%, the control centre will instigate an injection of additional water at the injector wells (i.e. “wet the WAG”).

Gas processing depends on the simple logic: if the product gas does not have enough methane and higher hydrocarbons to make processing worthwhile, then simple compression and re-injection is the best approach. By controlling the product gas to <85% CO<sub>2</sub>, the decision at SACROC is to process the gas.

The gas from the producer wells (typically 80% CO<sub>2</sub>; 5% methane; 15% heavier hydrocarbon gases at a pressure of 14 bar) is further compressed to 35 bar, dewatered by a regenerative desiccant unit, chilled and fed to a number of membrane gas separation units. These “Cynara” gas separation membranes, manufactured by NATCO Group, are based on extruded cellulose tri-acetate, asymmetric, hollow fibres that allow CO<sub>2</sub> (and H<sub>2</sub>S) to permeate faster than methane and other hydrocarbons (due to the partial pressure of the CO<sub>2</sub> and its relatively straight molecular structure). The result is a CO<sub>2</sub>-rich permeate stream and a CO<sub>2</sub>-lean non-permeate stream. The capacity of the membrane units at SACROC has been expanded recently by 2.3 million Nm<sup>3</sup>/day to a total of 5.1 million Nm<sup>3</sup>/day by the installation of new, second generation Cynara membrane units. It is interesting to note the dramatic

decrease in the size of these units for a higher throughput. The new membrane gas separation units are shown in the photograph below.

The non-permeate stream (typically >90% hydrocarbon gases; <10% CO<sub>2</sub>) is processed in a standard gas plant to produce natural gas liquids (ethane, propane, butane, etc). Any remaining CO<sub>2</sub> is scrubbed out using an amine scrubbing plant (that used to handle the entire gas separation prior to the installation of the first membrane units) and fed back to the CO<sub>2</sub>-rich stream.

The membranes are also effective at separating the higher carbon hydrocarbon gases and volatiles from low carbon ones. The revenue from the additional gas production has been greater than expected, and has made a significant contribution to the profitability of the SACROC operation.

The CO<sub>2</sub>-rich stream (typically 92-95% CO<sub>2</sub>; 5% methane) is re-compressed from 2.75 bar to 117 bar, cooled from 48°C to 30°C in a cooling tower (necessary to keep the CO<sub>2</sub> in a dense phase) and returned to the injector network via the 2,240kW pump described earlier (topped-up as necessary with CO<sub>2</sub> from the CRC Pipeline).

The SACROC oilfield has a power requirement of 60-70MW, with about 55% of this being associated with compression and re-compression. Much of the balance is associated with water pumping and well pumping. As the operation develops, the power capacity will be increased to 120MW, with some on-site self-generation planned. One interesting point to note is that it is planned to increase the pressure of the gases returning from the separator tank batteries to the gas processing complex from 14 bar to 21-24 bar and operate the membrane separators at this pressure rather than at 35 bar as is currently the case: This will eliminate the need for compression prior to gas separation so reducing the power requirement by around 25%.

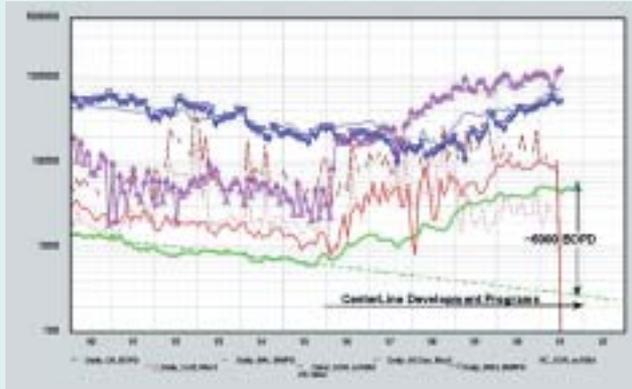
Production costs for tertiary production at SACROC are approximately US\$15-16/bbl.

The diagram below illustrates the overall trends, since 1990, in injecting CO<sub>2</sub> and water, and the effect on the production of oil, water and gases. The incremental oil production trend, resulting from the better optimised second CO<sub>2</sub>-EOR phase from 1995, is clearly evident, with an incremental 6,000 BOPD (approximately) indicated.

*New Membrane  
Gas Separation  
Plant at SACROC*



*Injection/  
Production  
Trends for  
SACROC  
Center-Line  
CO<sub>2</sub>-EOR  
(courtesy of  
Kinder  
Morgan CO<sub>2</sub>  
Company L.P.)*



Kinder Morgan believe that they can increase this substantially in the next five years, increasing field production to 50,000 BOPD, virtually all of which will be attributable to CO<sub>2</sub>-EOR. Furthermore, it is believed that this production level can be sustained until 2020 or beyond. This incremental recovery due to CO<sub>2</sub> injection represents 13-15% OOIP for that part of the field subject to CO<sub>2</sub>-EOR, or 6% OOIP for the whole Unit. Put another way, the total incremental oil production since 1995 will amount to perhaps as much as 200 million barrels – bigger than most operations being planned in the deep waters of the Gulf of Mexico. On average in the Permian Basin, 140-200Nm<sup>3</sup> of CO<sub>2</sub> (0.26-0.37tCO<sub>2</sub>) is required to yield a barrel of CO<sub>2</sub>-EOR oil.

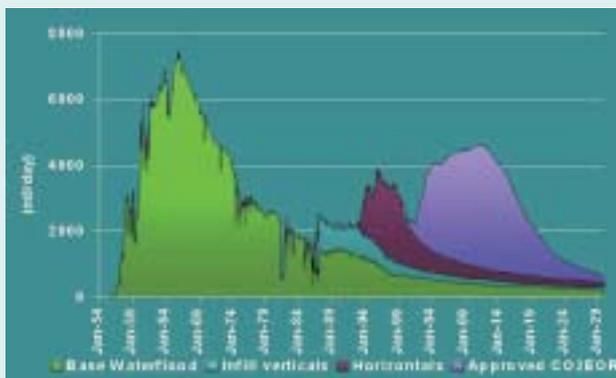
#### **EnCana's Weyburn CO<sub>2</sub>-EOR Operation, Saskatchewan**

##### History

The Weyburn oilfield, some 130km SE of Regina, was discovered in 1954 with an estimated 1.4 billion barrels OOIP. Primary production/depletion commenced in 1955, with production (by gas expansion) rising rapidly to about 31,500 BOPD by the end of 1963.

Secondary production using an extensive waterflood was initiated in 1964. Production peaked at about 47,200 BOPD in 1966 but declined steadily over the following 20 years to the level of 9,400 BOPD by 1986. This production was supplemented by a programme of drilling additional vertical infill wells from 1986, and horizontal wells in the "pay zone" from 1994. The vertical infill wells boosted production up to around 12,600 BOPD, with the horizontal wells further increasing production up to around 22,000 BOPD. However, by 1998, cumulative production was approaching 330 million barrels of oil (23% OOIP) and production was once more in decline. The secondary production operations are expected to yield a total of 350 million barrels of oil, i.e. 25% OOIP. The development history of Weyburn is illustrated below.

*Development  
History for  
Weyburn  
(courtesy of  
PTRC)*



In recognition of this, discussions began in 1995 concerning the supply of about 3.4 million Nm<sup>3</sup>/day of CO<sub>2</sub> from the Dakota Gasification Company (DGC) to EnCana Resources, (formerly Pan-Canadian Petroleum Ltd) Canada's largest oil company, who owned 70% of the Weyburn oilfield (the remaining 30% was owned by 36 smaller companies). EnCana was proposing a C\$1 billion investment over five years for a large-scale CO<sub>2</sub>-EOR project. In June 1999, the Government of Saskatchewan, after

extensive consultancy with EnCana, announced that it had developed a special royalty and tax framework for the Weyburn CO<sub>2</sub> project, which was designed to encourage commercial development of CO<sub>2</sub>-EOR operations in the Province. On this basis, it negotiated a long-term (15 year) contract to purchase up to 2.7 million Nm<sup>3</sup>/day of CO<sub>2</sub> from DGC. This required DGC to build a 330km pipeline from their Great Plains Synfuels Plant near Beulah in North Dakota to the Weyburn oil field; this was completed early in 2000. This pipeline is described in more detail in Section 6.2.2.

In August of 1999, a workshop was held in Regina to determine the feasibility of launching a research project, in conjunction with the CO<sub>2</sub>-EOR production at Weyburn, into the long-term fate and security of CO<sub>2</sub> storage in geological structures. Based on the support and encouragement at this workshop, a major international research consortium was established and funding requests made to various governments/agencies and industry partners early in 2000. The International Weyburn CO<sub>2</sub> Monitoring and Storage Project was launched in July 2000 by PTRC (located next to the University of Regina) and EnCana. The project, which is now funded by a number of governments and industrial sponsors from North America, Europe and Japan, is described in more detail in Section 7.2.1. The CO<sub>2</sub>-EOR activity started in September 2000.

#### Current Activities at Weyburn

The Weyburn oil field is one of a number of large oil fields that lie along the Mississippian (lower Carboniferous – equivalent in age to some of the Carboniferous limestone in the UK) sub-crop belt on the northern extent of the Williston Basin. This Basin extends across much of southern Saskatchewan, the SW corner of Manitoba, much of North Dakota and parts of Montana and South Dakota. Medium gravity crude oil occurs in a 1.5-15m thick pay zone known as the Midale Beds at an average depth of 1,420m. The Midale Beds comprise two distinct beds that each vary in occurrence and thickness across the field and have different porosity and permeability values. The Marly layer (dolomite) has a porosity that varies from 20% to 37% (averages 26%) and a permeability that varies from 0.1mD to 150mD (averages 10mD), while the Vuggy layer (limestone) has a porosity that varies from 2% to 15% (averages 15%) and a permeability that varies from 0.01mD to 500mD (averages 30mD). The Weyburn Field covers an area of 18,000ha and extends to approximately 12km by 16km.

The CO<sub>2</sub> from DGC is 96%+ pure, with typically 0.9% H<sub>2</sub>S content. As for SACROC, the CO<sub>2</sub> is transported dry and at such a pressure (152 bar) that it remains a dense phase, supercritical fluid for ease of pumping and to minimise corrosion. Although EnCana contracted to purchase up to 2.7 million Nm<sup>3</sup>/day of CO<sub>2</sub> from DGC, it currently requires 80% of this (2.2 million Nm<sup>3</sup>/day), although this will increase as the next phase of the CO<sub>2</sub>-EOR commences (mid 2003).

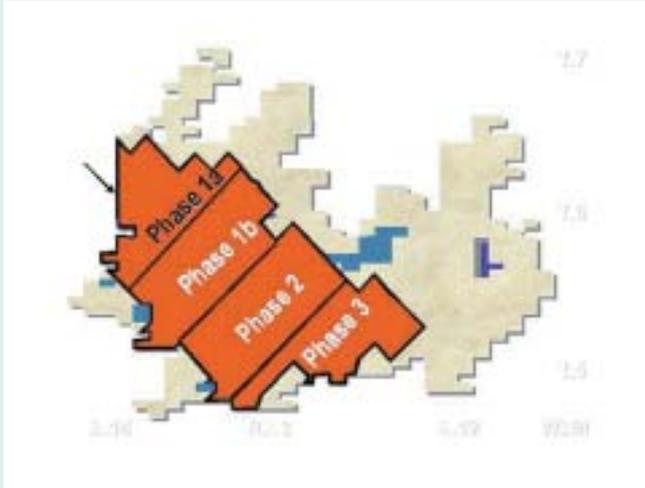
The CO<sub>2</sub> pipeline from Beulah surfaces at EnCana's CO<sub>2</sub> receiving terminal where it is combined with the recycled and re-compressed CO<sub>2</sub> from the producer wells. Currently, some 0.5 million Nm<sup>3</sup>/day of CO<sub>2</sub> is recycled from the oil gathering network, which, when combined with the CO<sub>2</sub> from the Beulah pipeline, provides the 2.7 million Nm<sup>3</sup>/day (about 5,000 tonnes/day) of CO<sub>2</sub> required for the Phase 1a CO<sub>2</sub>-EOR operation. This CO<sub>2</sub> is piped to CO<sub>2</sub> injection satellites that feed the individual injector wells.

The operation at Weyburn differs significantly from SACROC in that Weyburn targets a single, relatively thin oil-bearing layer, whereas SACROC targets several oil-bearing zones that can be accessed in a single vertical well. At Weyburn, the drilling of horizontal wells has been necessary to maximise well contact with the target reservoir.

The Weyburn oil field has a total of 720 wells of which 320 are automated. Phase 1a of the CO<sub>2</sub>-EOR operation, which covers 4,920ha, involves 134 wells (29 injector wells and 105 producer wells). The next phase of operation, Phase 1b, will involve a further 48 wells (8 injector wells and 40 producer wells) and is due to commence in mid 2003 (depending on the rate of recycling of CO<sub>2</sub>).

The wells at Weyburn were drilled in a "9-spot" grid pattern (i.e. eight producers in a square around a single injector) and typically have a spacing of around 150m. This has proved effective for CO<sub>2</sub>-EOR. In preparation for the CO<sub>2</sub>-EOR operation, EnCana had to drill a number of producer wells to complete the pattern or convert some wells from producer to injector or vice versa. It was also decided to drill many deviated horizontal holes, usually two per well in a "tuning fork" pattern, for both some injector wells and some producers. The extensive waterflood operations since 1964, together with more detailed geological investigations leading up to the Phase 1a activity, have provided excellent reservoir knowledge and enabled optimisation of the CO<sub>2</sub> flood. The diagram below illustrates the planned phases of the CO<sub>2</sub> flood.

Phases for  
CO<sub>2</sub>-EOR at  
Weyburn  
(courtesy of  
PTRC)



The 29 injector wells (13 horizontal “tuning fork” layout CO<sub>2</sub>-only injectors and 16 vertical WAG injectors) active in Phase 1a, inject the 2.7 million Nm<sup>3</sup>/day of CO<sub>2</sub> – a constant injection volume, controlled by manually set choke valves – and 3,200m<sup>3</sup>/day of water at a pressure of around 152 bar in a WAG pattern. Other, water only, vertical injectors maintain a water curtain around the CO<sub>2</sub>-EOR area, preventing CO<sub>2</sub> losses laterally away from the producers.

The injector well configuration is very similar to that at SACROC, with the addition of a small, fibreglass wellhead enclosure (colour coded tan) to protect the structure in the harsh weather conditions and to allow leaks to be detected. The H<sub>2</sub>S gas in the recycled CO<sub>2</sub> is useful for leak detection and H<sub>2</sub>S detectors are used in preference to CO<sub>2</sub> detectors. Water injection wells are similarly protected by green fibreglass shells.

Of the 105 producer wells (over half of which are horizontal “tuning fork” layout and the remainder vertical single leg wells) in Phase 1a, 36 have responded so far to the CO<sub>2</sub> injection that commenced in September 2000, with approximately one additional well responding each week. These wells are producing around 7,000 BOPD, 0.5 million Nm<sup>3</sup>/day of gases (CO<sub>2</sub> and hydrocarbon gas) and varying amounts of water in emulsion with the incremental oil.

Pumping, where needed, is performed by a mixture of electric submersible pumps (on higher production wells), “pump jacks” (i.e. rod pumps) and “Rotoflex” pumps (i.e. rod pumps driven by a belt system), however, some wells are free flowing or “flumping” (i.e. free flowing at times and requiring pumping at other times – with pumping cycles controlled using transducers). The most productive well in the Phase 1a operation is producing a total of 420m<sup>3</sup>/day of emulsion. A gas:oil ratio at the producer wells is typically 35:1 (m<sup>3</sup>/m<sup>3</sup>), but can be higher on some producing wells. To combat corrosion, chemical corrosion inhibitor fluids are routinely used in the annular space between the casing and the tubing. When a well is shut-off for any extended time period, the well is filled with inhibitor fluid. Linings have not been used to date.

The product from the producer wells (at varying pressures, controlled by choke valves, depending on distance) is piped in fibreglass flowlines to one of five “oil satellites” - gathering points/group separators, which each handle the output from up to 30 wells. The product flowlines from the wells are combined in stainless steel manifolds (see photograph below) and fed to a three phase test separator unit (i.e. gases, water and emulsion) for routine monitoring of product constituents, and a large two phase separator vessel that separate the gases (CO<sub>2</sub> and hydrocarbon gases) from the emulsion (oil and water).

The emulsions from the EOR satellites are combined with the liquids produced from 73 existing conventional oil satellites and processed centrally through water knock-out vessels and standard oil treaters to separate the water and any residual CO<sub>2</sub> dissolved in the fluids. The recovered water is passed to the water injection plant for re-injection and the dewatered oil goes directly to oil sales. The CO<sub>2</sub> separated in this emulsion processing plant is at a low pressure (0.2 bar) and needs to be compressed in a battery gas compressor to 6.5 bar in order to be recombined with the gases from the EOR oil satellites.

*Producer Well  
Flowlines  
Manifold at  
an EOR Oil  
Satellite*



Unlike SACROC, the hydrocarbon gases produced from the CO<sub>2</sub>-EOR producers are not separated from the CO<sub>2</sub> but are pressurised and recycled with the CO<sub>2</sub> for re-injection. The same is not true of the conventional secondary production wells, where, since there is no CO<sub>2</sub> being produced, the gaseous phase is predominantly hydrocarbons and goes directly to gas sales. The EOR satellite product gases are fed through an inlet separator (a retention time vessel to knock out any remaining water and oil) and recombined with the CO<sub>2</sub> from the fluids treatment facilities before compression to 152 bar by two 4.5MW (4-stage) recycle gas compressors (with inter-stage cooling and associated liquids capture) to be fed back into the CO<sub>2</sub> injection network, topped up from the DGC pipeline, as required.

The incremental oil production due to the CO<sub>2</sub>-EOR operation at Weyburn is currently about 5,000 BOPD: This is expected to increase to about 22,000 BOPD over the next ten years. EnCana expects to inject some 20 million tonnes of CO<sub>2</sub> over the 20 year project life and produce an incremental 130 million barrels of oil – 9% OOIP (expected recovery factor is around 16%, but current plans are to implement CO<sub>2</sub>-EOR on only the best portion of the total unit). This will increase the overall recovery of oil from the Weyburn oilfield to 38% OOIP and extend the field's life by around 25 years.

### 8.1.3 Other Activities Ongoing in North America

The **CO<sub>2</sub> Capture Project (CCP)**, led by BP, has been described in Section 4.4.1. This major international collaboration has recently started a one year "focused technology development" phase examining around 20 of the technologies that have been judged most likely to meet the Project's stringent cost reduction and technology development status targets. While the Mission team were unable to ascertain which technologies have passed the screening criteria, it is clear that CO<sub>2</sub>-EOR from depleting oil fields represents one of the most promising CO<sub>2</sub> storage routes.

The **US DOE's Carbon Sequestration Program**, described in detail in Section 4.2.2, is currently committing some 40% of its budget (expected to be \$40-45 million in 2003) on geological sequestration. This pathway of investigation addresses EOR from depleting oil fields, ECBM recovery from unmineable coal reserves and storage in saline aquifers.

As the programme's activities develop from R&D, to regional partnerships (i.e. developing regional inventories of CO<sub>2</sub> sources and sinks, establishing verification protocols, testing sequestration technologies at small scale, etc.), and from there to integrated power plant capture and geological sequestration demonstrations, CO<sub>2</sub>-EOR is likely to be an option of great interest.

### 8.1.4 The Economics of CO<sub>2</sub>-EOR in North America

Both the SACROC operation of Kinder Morgan and the Weyburn operation of EnCana are only economically attractive enterprises on account of the fiscal regimes in which they operate. Without such tax credits or royalty adjustments, neither operation would be profitable.

The economics of CO<sub>2</sub>-EOR are determined by a large number of factors, of which the most significant are the prevailing oil price, the EOR yield (i.e. units of oil per unit of CO<sub>2</sub>), the cost of CO<sub>2</sub> and the capital costs of EOR plant.

Much of the economic information concerning the two operations visited during the course of the Mission is commercially sensitive (e.g. the costs of plant), but information on yield was available and is included in the descriptions of the operations above.

The cost of CO<sub>2</sub> delivered to SACROC and Weyburn, while not made directly available, was estimated by the Mission team to be approximately \$20/tonne and \$19/tonne respectively.

The Rate of Return of the SACROC operation was around 12-15%, which may not be attractive to an oil "major", but appears sufficient for a company like Kinder Morgan to keep investing in expanding their operation.

#### 8.1.5 Implications and Lessons for the UK

From the two site visits and the several meetings concerning CO<sub>2</sub>-EOR, a number of key points relevant to any application of CO<sub>2</sub>-EOR for tertiary oil production in the UK emerge:

- EOR using CO<sub>2</sub> injection is an established technology in widespread use in the USA and at two oilfields in Canada, with over 30 years experience existing in West Texas. It is applicable to a wide range of geological conditions, porosities and permeabilities.
- CO<sub>2</sub>-EOR makes a significant contribution to oil production in the USA, accounting for around 200,000 BOPD. This is particularly true of West Texas where CO<sub>2</sub>-EOR accounts for more than 20% of oil production. (The billionth barrel of CO<sub>2</sub>-EOR oil was produced from West Texas this year).
- CO<sub>2</sub>-EOR is enabling significant amounts of incremental oil to be recovered (13-15% OOIP at SACROC and 9% OOIP at Weyburn) and significantly extending the operating life of those oil fields deploying it.
- Strong parallels exist between the current position in the North Sea with the situation in West Texas at the time of the last major oil crisis when EOR was used to boost US production. Security of supply, as in the UK now, was an increasingly important issue. Successful implementation relied on the introduction of financial incentives and had major benefits in terms of increased security of supply, more jobs and a greater contribution to the GDP. Importantly these were longer term in nature and necessary to encourage the required investment.
- Long-term commercial contracts exist between CO<sub>2</sub> suppliers and users (for example at the Weyburn Project between Dakota Gasification Company and EnCana Resources).
- CO<sub>2</sub>-EOR is stimulating a market for CO<sub>2</sub> and, in some cases, leading to early trading in emissions reductions.
- There are no significant technical problems to the deployment of CO<sub>2</sub>-EOR (corrosion problems have been largely solved, H<sub>2</sub>S has not proved to be a problem and many technologies to aid operations have been developed).
- The use of WAG techniques has been largely optimised and allows effective recovery and cost effective operation. In North Sea applications, where well spacing is likely to need to be much greater, gravity stabilised gas injection (GSGI) techniques might be more appropriate. While GSGI methods may produce more oil and allow more CO<sub>2</sub> to be stored, with the need for fewer wells, "breakthrough" periods are likely to be longer.
- Effectiveness of CO<sub>2</sub>-EOR depends on a good understanding of the geology and the conditions for miscibility.
- CO<sub>2</sub>-EOR requires a certain pressure in the strata and a certain specific gravity of oil to be effective.
- CO<sub>2</sub> is relatively easy to handle when it is in a dense phase (supercritical fluid). This requires a certain operating pressure to be maintained. However, compression costs are significant.
- Separating CO<sub>2</sub> from hydrocarbon gases is relatively simple, where the economics merit it. Membrane technology has much to offer and can provide an optimised technology option when combined with amine scrubbing. Technology advances are continually happening in this area, notably size reduction and throughput increases.
- Highly effective collaborations between industry, governments and academia have been very beneficial in creating international demonstrations.

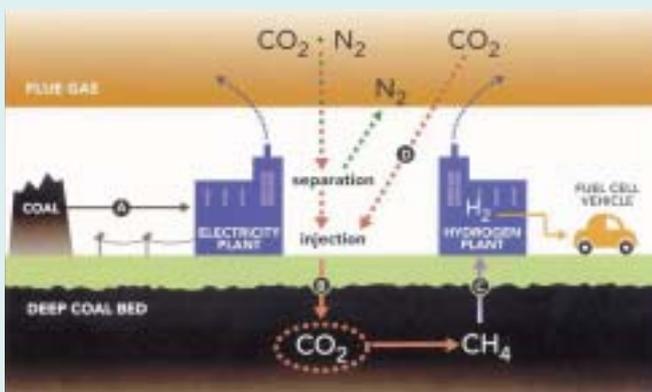
- Several onshore UK fields have more than 5 million barrels of OOIP, i.e. are above the minimum size considered for Permian Basin fields. Most onshore UK fields have only been produced through primary production techniques and will leave around 80-90% of OOIP on abandonment.
- A study, conducted under the DTI's Sustainable Hydrocarbons Additional Recovery Programme (SHARP), concluded that around 60 offshore fields are large enough to be considered as CO<sub>2</sub>-EOR candidates. Well spacing/patterns and reservoir management will be different to onshore EOR operations because of the limited well access offshore. Capital and operating costs and risks will be higher, however the rewards of prolonging field life and accessing additional oil, and the provision of infrastructure that would pave the way for dedicated CO<sub>2</sub> storage, might make such projects attractive in the medium to long term.

## 8.2 CO<sub>2</sub> Use for Enhanced Coal Bed Methane Recovery

Leading the research efforts into coal bed CO<sub>2</sub> sequestration is the Provincial research organisation, the Alberta Research Council (ARC) [www.arc.ab.ca](http://www.arc.ab.ca). ARC carries out applied research in many fields, including energy technologies, and serves the Canadian oil industry with a comprehensive range of capabilities, recently expanded to cover climate change technologies. Its work on gas separation, fuel cells, and alternative fuels should come as no surprise, but it is perhaps better known in the UK for its work on reducing GHG emissions using enhanced coal bed methane (ECBM). Injecting CO<sub>2</sub> into deep, unmineable coal seams displaces methane from the coal. The produced methane, very similar to natural gas, can be used as a fuel, whilst the CO<sub>2</sub> remains sequestered. Alberta's deep coal beds have the capacity to store 18,300MtCO<sub>2</sub><sup>27</sup>, equivalent to almost 30 years' CO<sub>2</sub> emissions from the whole of Canada. Based on a forecast of CBM production made by Canada's National Energy Board<sup>28</sup>, it is estimated that 380MtCO<sub>2</sub> could be sequestered each year by 2025 - approximately half of Canada's GHG emissions. A similar picture emerges in Australia, China and elsewhere in the world where coal permeability is sufficient to allow ECBM operations. Currently, the high costs of CO<sub>2</sub> capture and compression mean that the economics of ECBM are not as attractive as EOR, but ARC's experimental and analytical work, including a micro-pilot test well, is adding to the knowledge base that will determine if ECBM has a future role. It is worth noting here that ARC's ECBM project is supported by an international group of 28 interested parties, including the UK DTI and some major oil companies, but no coal mining companies.

The diagram below illustrates a possible ECBM energy chain for reducing GHG emissions in which: coal is burned (A) to produce electricity and flue gases; the CO<sub>2</sub> (B) is captured and injected into deep, unmineable coal measures; the coal adsorbs the CO<sub>2</sub> releasing methane (C); the methane is produced and reformed into H<sub>2</sub> and CO; the H<sub>2</sub> is used in fuel cell vehicles and pure CO<sub>2</sub> (D) is injected back into the coal bed.

Reducing  
GHG  
Emissions  
using ECBM



<sup>27</sup> Wong, S., Gunter, W. D. and Mavor, M. J. (2000a) Economics of CO<sub>2</sub> sequestration in coalbed methane reservoirs, Society of Petroleum Engineers paper no. SPE 59785 presented at the 2000 SPE/CERI Gas Technology Symposium, Calgary, Alberta, Canada, 3-5 April.

<sup>28</sup> National Energy Board (1999) Canadian energy supply and demand to 2025, Calgary, Alberta, Canada: National Energy Board, 30 June.

## 8.2.1 Background to the Technology

### Methane in Coal

Whilst the anaerobic biodegradation of plant matter produces methane, and is probably the first step of coalification, this biogenic methane is likely to escape to atmosphere (or into porous geological strata) well before the latter stages of coalification. The methane found in coal is predominantly thermogenic, the result of the increasing temperatures and pressures which increase the coal's carbon content or "rank" with the loss of hydrogen and oxygen as water, carbon dioxide and methane. There are examples from Europe (e.g. Poland) where coal has been enhanced with methane by microbial remobilisation via groundwater invasion millions of years before the present day.

The main mechanism of methane retention in coal beds is physical adsorption, i.e. retention on the large surface area found within coal's micropore structure<sup>29</sup>. By contrast, natural gas reservoirs consist primarily of compressed methane gas in void spaces.

Methane is released, or desorbed from the coal when it is de-stressed and fractured during, for example, mining operations. The rate of methane desorption depends upon the coal's permeability (typically 1-60mD) which itself depends upon many complex factors including the cleat structure and microfracturing.

Coal mine methane, or "firedamp" as it is also known, is captured at operational mines for safety reasons, allowing gassy coal seams to be worked without risk of explosion. The captured methane is often of a sufficiently high purity (>30%) to allow it to be used safely in gas engines (usually reciprocating) for power generation.

### Coal Bed Methane (CBM)

The production of coal bed methane (CBM) from coal seams conventionally requires the drilling of many vertical boreholes from the surface into the coal seam. Hydraulic fracturing ("hydrofracturing") is usually required to form a cavity and fractures into the coal measures to assist gas flow. Hydrofracturing is an art and the better the resulting gas flow paths, the fewer the wells needed in a CBM field. An alternative to hydrofracturing is to use directional drilling technology to create horizontal, in-seam boreholes. The larger contact area with the coal increases gas productivity, but drilling contractors are cautious about in-seam drilling in UK coals<sup>30</sup> and experience based on long holes drilled from working underground mines suggests gas productivity may be low in any case.

Four factors determine the attractiveness of CBM:

- the gas content of the coal (measured in m<sup>3</sup>/t and ranging from a trace to 25m<sup>3</sup>/t);
- the nature of fracturing and permeability of the coal, measured in milli-Darcy (below 1mD and CBM is not practical<sup>31</sup>);
- the seam thickness, which might be the aggregate of a number of smaller seams; and
- the water content and its quality (i.e. is dewatering required and is water disposal likely to be a problem?).

It is a favourable combination of these factors that determines whether particular coal measures lend themselves to CBM extraction. For example the sub-bituminous coals of the Powder River Basin in Wyoming, USA, have low gas content but high permeability (10-1,000mD) and are good CBM producers.

Microbial technology may have a role in enhancing the production of methane from some coals, and research into methanogens continues. In addition to the direct conversion of some coal components (e.g. n-alkanes) into methane, the microbes may enhance the permeability of coal seams by removing pore-plugging waxes. This is a complex subject and production rates may be limited by the formation temperature, accumulation of toxic waste products and the cleat areas accessible to microbes. The coal must also be of sufficient permeability to allow microbes to be introduced, but the biomass formation itself could reduce permeability.

<sup>29</sup> Davidson, R. M., Sloss, L. L. and Clarke, L. B. (1995) Coalbed methane extraction, report no. IEACR/76, London: IEA Coal Research, January.

<sup>30</sup> Creedy, D. P., Garner, K., Holloway, S. and Ren, T. X. (2001) A review of the worldwide status of coalbed methane extraction and utilisation, report no. COAL R210, DTI/Pub URN 01/1040, London: Department of Trade and Industry.

<sup>31</sup> Hughes, B. D. and Logan, T. L. (1990) How to design a coalbed methane well, *Petroleum Engineer International*, 5(62), pp.16-20, May.

Most coal bed methane reserves lie in deep coal seams that have not been mined and are unlikely to be mined. There has been little commercial exploitation of this fossil fuel resource, despite considerable exploration and testing. In the USA, "Non-conventional Fuel Tax Credit" incentives have resulted in extensive development in the San Juan (Colorado and New Mexico) and Black Warrior (Alabama) coal basins. CBM gas production from these now accounts for about 8% of dry natural gas production in the USA<sup>32</sup>. Outside of the USA, there has been very little CBM activity; lack of local markets and/or gas pipeline infrastructure has limited development in Australia and China, whilst low seam permeability is a major constraint in Europe. In Canada, the CBM resource is estimated to be more than 6,000 billion m<sup>3</sup><sup>29</sup> compared with proved natural gas reserves of 1,690 billion m<sup>3</sup><sup>33</sup>; yet, there is only one well producing commercially in southern Alberta. The low permeability of Canadian coal measures has inhibited exploitation.

#### Enhanced Coal Bed Methane (ECBM)

Methane can be "swept" from coal measures using nitrogen or CO<sub>2</sub>. Two physical effects enhance the production of methane:

- a reduction of the partial pressure of methane in the fracture network of the coal results in enhanced methane desorption from coal surfaces; and
- carbon dioxide is preferentially adsorbed onto coal surfaces and so displaces additional methane (the ratio of CO<sub>2</sub> molecules adsorbed for each methane molecule released is around two in high volatile bituminous coals and up to 10 in sub-bituminous coals).

In ideal, homogenous coal measures, the CO<sub>2</sub> is not expected to "breakthrough" from the injection well to production wells until the bulk of the methane has been produced<sup>27</sup>. In situations where there is no value attached to the sequestered CO<sub>2</sub>, this becomes an expensive loss of working fluid. Nitrogen is then the preferred gas for enhanced methane production because it can be separated from the methane and recycled over and over again with far less adsorption loss. The ECBM strategy adopted depends on economic factors: natural gas selling price, eligibility and value of any CO<sub>2</sub> credits, and the cost of the injectant.

Whilst there is some research into ECBM as a means of sequestering CO<sub>2</sub>, like conventional CBM, it does depend upon the coal seams having a moderate to high permeability, certainly >1mD. This presents an apparently insurmountable barrier to the commercial development of such techniques in many parts of the world. However, Canada, the European Union (the RECOPOL project) and the USA (the Coal-Seq project) are funding research projects to understand this important sequestration option.

#### 8.2.2 Operational and Practical Issues

There have been two ECBM trials in the world using CO<sub>2</sub>:

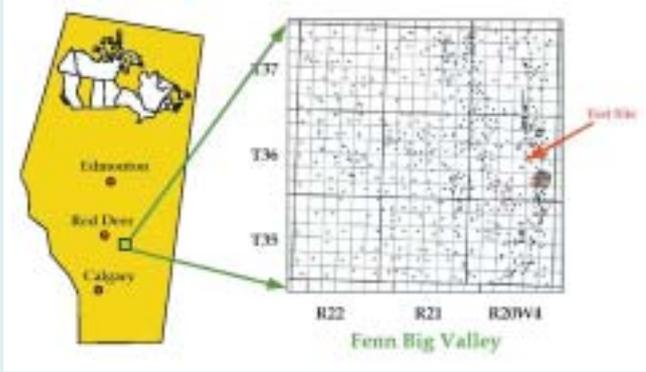
- Since 1996, Burlington Resources in the US San Juan Basin, New Mexico, has injected 57 million Nm<sup>3</sup> (2Bscf) of CO<sub>2</sub> from a natural source at its Allison Unit<sup>34</sup>. Increased methane production has been observed with no CO<sub>2</sub> breakthrough. The cost of the 98% pure CO<sub>2</sub> is estimated to be approximately \$12.35/tCO<sub>2</sub>. CO<sub>2</sub>, occurring naturally in the coal, is produced along with the methane and, given its low concentration, this does not have to be separated. However, if breakthrough of the CO<sub>2</sub> injectant occurs, then this would negate any sequestration benefits unless it was separated. The cost implications of a separation plant are clear.
- ARC has completed its single well, micro-pilot field test in a Gulf Canada CBM well at Fenn-Big Valley in Alberta, including tests to determine the benefits, both technical and economic, of using a mix of CO<sub>2</sub>/N<sub>2</sub> to enhance methane production.

<sup>32</sup> EIA (2001) U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 2001 Annual Report, Energy Information Administration.

<sup>33</sup> BP (2002) BP statistical review of world energy, London: British Petroleum plc, June.

<sup>34</sup> Stevens, S. H., Kuuskraa, V. A., Spector, D., and Riemer, P. (1998) CO<sub>2</sub> sequestration in deep coal seams: pilot results and worldwide potential, presented at the Fourth International Conference on Greenhouse Gas Control Technologies, Interlaken, Switzerland, 30 August - 2 September.

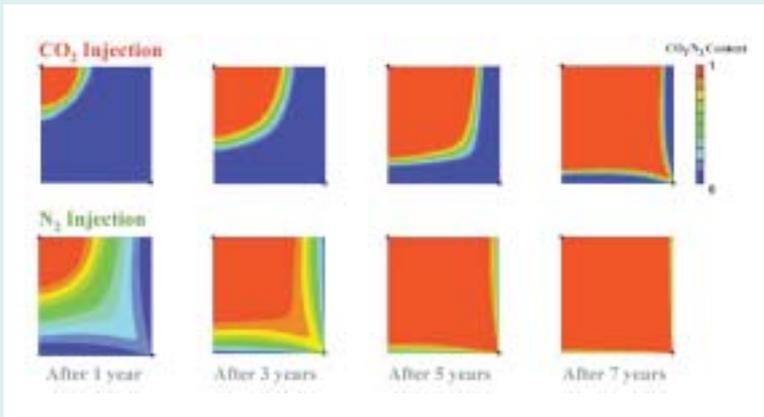
Location of Alberta Research Council's ECBM Test Site



ARC's micro-pilot test was the second phase of a three phase R&D programme:

- Phase I: Proof of concept study - initial assessment and feasibility of injecting CO<sub>2</sub>, N<sub>2</sub> and flue gases into Mannville coals (completed July 1997)
- Phase II: Design and implementation of a single well, micro-pilot test using a "huff and puff" approach to ECBM (completed April 1999)
- Phase IIIA: Flue gas injection into a new, second well at test site (completed spring 2000)
- Phase IIIB: Design and implementation of a full-scale, 5-well, pilot project (now scheduled for 2005)

Numerical Modelling of a 5-spot Pattern ECBM Well Layout for a Constant Injection Rate (one quarter of 5-spot pattern shown)



As a part of Phase II, ARC evaluated a number of commercial software packages for reservoir simulation. Although adequate for predicting primary CBM production, they have shortcomings when modelling the ECBM micro-pilot test. Improved understanding of multiple gas sorption/diffusion and possible changes in the coal matrix volume due to adsorption of CO<sub>2</sub> (a swelling that leads to reduced permeability) are needed to improve future simulation models.

Collection of Core Samples and Pressurised Storage to Determine Gas-in-place, Gas Composition and Gas Storage Capacity during Drilling of Second Well at Fenn-Big Valley Micro-pilot Test Site



*Flue Gas  
Injection into  
Test Well at  
Fenn-Big Valley  
Micro-pilot  
Test Site*



The potential of ARC's work with gas mixtures is the use of unprocessed flue gases as the injectant, thus avoiding the costly CO<sub>2</sub> capture stage. Pure CO<sub>2</sub>, pure N<sub>2</sub>, 47:53 CO<sub>2</sub>:N<sub>2</sub> and 13:87 CO<sub>2</sub>:N<sub>2</sub> (exhaust gases from a compressor engine) have all been injected during the Phase IIIA "huff and puff" tests. If the produced gas is used on-site, the nitrogen that breaks through may not need to be separated; however, corrosion issues when injecting flue gases are not trivial. With the CO<sub>2</sub>:N<sub>2</sub> ratios found in raw flue gases, there would be no avoided CO<sub>2</sub> since the amount sequestered would be roughly equal to the additional emissions from flue gas compression<sup>35</sup>. The coal reserves at Fenn-Big have a low permeability (1-5mD), so results of the tests are of international importance; they are currently being processed and will be reported in due course.

ARC has performed a preliminary economic analysis for a conceptual 100 well ECBM field to exploit coal reserves lying at 1,280m comprising two seams totalling 9m. A 5-spot, 130ha well pattern (an injection well surrounded by four producing wells) is proposed to recover about 72% of the estimated 125 million Nm<sup>3</sup> (4.4Bscf) of gas-in-place. With a CO<sub>2</sub> cost of \$19/tCO<sub>2</sub>, ARC calculates a gas production cost of \$81.84/million Nm<sup>3</sup> (~20p/therm) dropping to \$44.75/million Nm<sup>3</sup> (~11p/therm) where flue gas is the injectant.

### 8.2.3 Implications and Lessons for the UK

It is widely recognised that CBM development needs are country and coalfield specific. As such, care must be taken not to assume that the rather encouraging reports from ARC's work can be applied to the UK situation.

The CBM resource in the UK is estimated to be around 2,000 billion m<sup>3</sup><sup>29</sup>. This can be compared with the UK's proven natural gas resource of 730 billion m<sup>3</sup><sup>33</sup>. Unfortunately, due to the low permeability of UK coals, the potentially recoverable volume of CBM is estimated to be 30 billion m<sup>3</sup>, just 1.5% of the total resource.

Up to 1999, nine CBM wells had been drilled in the UK; with development hindered by gas ownership issues. Since then, five more wells have been drilled into unmined coal seams, and a further three wells into areas of coal that have been de-stressed due to mining activity (all by Evergreen Resources (UK) Ltd.). The latest drilling techniques and production enhancement techniques were used (air-foam drilling, nitrogen-foam fracking and coiled tubing).

Unfortunately, there has been insufficient information published from CBM exploration and testing activity in the UK to determine whether favourable conditions exist. Current indications are that gas production rates may be low to marginal. Results from tests by Evergreen Resources will provide a definitive answer and these are awaited with interest.

The same conclusions apply equally to ECBM schemes where there would be additional value in sequestering CO<sub>2</sub>. Presentations made to the UK Mission team by ARC left some questions unanswered. In coals having low permeability, it would be expected to inject CO<sub>2</sub> under fracturing conditions, or following hydrofracking, to achieve acceptable injectivity. The costs and effectiveness of this have not been reported by ARC. In addition, coal matrix swelling during the preferential

<sup>35</sup> Wong, S., Gunter, W. D., Law, D. and Mavor, M. J. (2000b) Economics of flue gas injection and CO<sub>2</sub> sequestration in coalbed methane reservoirs, proceedings of the Fifth International Conference on Greenhouse Gas Control Technologies, Cairns, Australia, 13-16 August.

adsorption of CO<sub>2</sub> will tend to close the cleat system and reduce permeability (conclusively demonstrated by Mavor and Vaughan)<sup>36</sup>. Though there remains some uncertainty regarding the swelling effect, it has huge implications upon the ability to enhance the production of methane in low permeability coals. ARC needs to fully report its micro-pilot gas production and composition test results (alongside comparative simulation results) and make progress with the 5-spot trial, originally scheduled for 2001.

Until technologies are developed which allow a quantum leap in the production of CBM from low permeability seams, commercial exploitation of the UK's CBM resource seems unlikely. One possible revolutionary development would be the application of microbial technology to enhance CBM production<sup>37</sup>, and further work is needed to examine the compatibility of biogenic methane production with ECBM and CO<sub>2</sub> sequestration.

Despite this note of caution, the prize (including the enormous volume of offshore coal and lignite reserves on the UK Continental Shelf) is very great if ECBM can be successfully deployed. It is recommended that the DTI continues to support R&D work in this area at a level sufficient to better understand the ECBM process and to determine whether ECBM could be of benefit to the UK.

<sup>36</sup> Mavor, M. J. and Vaughan, J. E. (1998) Increasing coal absolute permeability in the San Juan Basin Fruitland formation, SPE Reservoir Evaluation and Engineering, pp.201-206, June.

<sup>37</sup> Scott, A. (2001) Benefits and limitations of revolutionary microbial technology to enhance coalbed methane production, presented at International investment opportunities in coalbed and coalmine methane, Hilton Green Park, London, 28 & 29 March.

## 9 Social, legal and research issues

Discussions were held with most of the organisations that the Mission team visited concerning non-technical aspects of CO<sub>2</sub> capture and storage. These included:

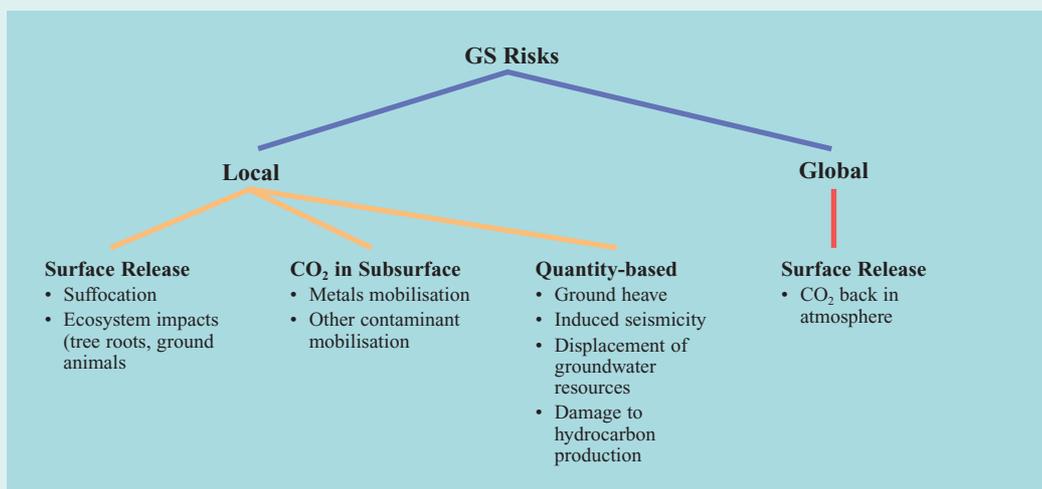
- health, safety and environment (HSE) aspects of CO<sub>2</sub> storage in geological structures;
- public perception of such operations;
- legal issues;
- fiscal frameworks to encourage CO<sub>2</sub>-EOR or ECBM recovery; and
- R&D requirements, positioning and co-operation needs and opportunities.

Such issues are complex and, consequently, this section aims to capture the main issues that came to light on the Mission.

### 9.1 Health, Safety and Environment

The main issues for health, safety and environment concern CO<sub>2</sub> leakage and associated risks and hazards. Pipeline leakage issues are addressed in Section 6.2.5 and surface activities associated with CO<sub>2</sub>-EOR operations are described in Section 8.1.2. This section of the report addresses HSE concerns associated with subsurface CO<sub>2</sub> storage. The diagram below illustrates the main areas of geological storage risk.

*Linkage of Risks Associated with Underground Geological Storage*<sup>38</sup>



The fact that many natural CO<sub>2</sub> accumulations have stayed underground in North America for thousands to millions of years is comfort that, in the right setting, geological storage of CO<sub>2</sub> is likely to be secure and pose no hazardous risk. However, these natural accumulations have had time to stabilise from the early effects that CO<sub>2</sub> may have had during the start of the accumulation. Several researchers are active in North America studying these natural analogues that could provide a long-term picture of the fate of large accumulations of CO<sub>2</sub> in the subsurface.

In some active volcanic areas in North America, natural CO<sub>2</sub> is leaking to surface. The most spectacular example of this phenomenon is that at Mammoth Mountain, California where CO<sub>2</sub> leakage is affecting vegetation and killing trees. There has also been one fatality attributed to CO<sub>2</sub> leakage. This area is being researched extensively by the US Geological Survey and partners in the BP-led CO<sub>2</sub> Capture Project consortium (see Section 4.4.1). One interesting approach has been the use of remote sensing (airborne and satellite) to image CO<sub>2</sub> seeps.

The greatest concern, especially for onshore CO<sub>2</sub> storage, surrounds the effect that CO<sub>2</sub> may have on groundwater, especially potable water. CO<sub>2</sub> in the presence of water is reactive and has an acidifying effect (i.e. reducing pH). This could have implications in the subsurface, as lowering pH can remobilise heavy metals. It is probable that any leakage of free gas to surface can be fixed (e.g. an old well leak can be capped) or the problem ameliorated, to some extent, by engineering solutions (e.g. better

<sup>38</sup> Wilson-Jackson, E. & Keith, D. W. 2002: Geologic carbon storage: understanding the rules of the underground. Sixth International Conference on Greenhouse Gas Control Technologies (GHGT-6), Kyoto, Japan, 1-4th October 2002.

ventilation in building basements, etc.). However, if potable water supplies are compromised, the damage could be permanent and an important resource lost.

Dense phase CO<sub>2</sub> is buoyant in brine and will try to rise, hence cap rock integrity is of fundamental importance in acting as a barrier to upwards CO<sub>2</sub> movement. Much effort is being placed on looking at the geochemistry of such barriers (e.g. in the International Weyburn CO<sub>2</sub> Monitoring and Storage Project – see Section 7.2.1), but less effort so far has been placed on the geomechanics (the Mission team were given a presentation on this aspect by the Geological Storage Research Group at the Department of Civil and Environmental Engineering, University of Alberta, Edmonton). The sheer physical displacement of brine by injecting CO<sub>2</sub> might cause brine ingress into overlying potable aquifers.

All these risks can be minimised by the careful selection of geological sites. The fact that at Kinder Morgan's SACROC Field CO<sub>2</sub> has now been injected for over 30 years without any major problems in respect to CO<sub>2</sub> leakage gives some degree of confidence that underground storage is feasible. In this context, the importance of the International Weyburn CO<sub>2</sub> Monitoring and Storage Project in building further confidence and understanding of CO<sub>2</sub> storage processes cannot be over-emphasised. If these settings for CO<sub>2</sub> injection, which are peppered with man-made conduits through the subsurface (e.g. hydrocarbon and water wells) and affected by pressure changes associated with hydrocarbon extraction, can store CO<sub>2</sub> securely, then carefully selected "virgin" storage sites should be extremely low risk.

An excellent review of HSE issues, from a North American perspective, with respect to underground storage of CO<sub>2</sub> is presented by Sally Benson of the Lawrence Berkley National Laboratory and can be downloaded from the CO<sub>2</sub> Capture Project website<sup>39</sup>.

## 9.2 Public Perception

The Mission team was told of a high degree of public acceptance of CO<sub>2</sub>-EOR. At the SACROC and Weyburn fields, dwellings and buildings are within a few tens of meters of surface CO<sub>2</sub>-EOR facilities. The team even saw a dwelling under construction immediately adjacent to a wellhead. In the town of Midland in West Texas, a high degree of public awareness was observed. At the town limits a sign welcomes you to the "Permian Basin" and a large museum with an assorted array of derricks, platforms and pumps outside proudly stands near the town centre. Surface CO<sub>2</sub>-EOR wellhead facilities are no more obtrusive than agricultural activities, and less so than overhead power lines, telephone wires etc. EnCana, operators of the Weyburn CO<sub>2</sub>-EOR operation, have regular contact with the local schools and press and organise an annual public meeting with the people of the town where questions and issues can be raised and answered. During the initial phase of CO<sub>2</sub> injection, mercaptan odours were a problem, however, EnCana have responded quickly by changing valve maintenance routines.

*Field Surface Facilities Near to Public Access and Dwellings at Weyburn*



<sup>39</sup> [www.co2captureproject.org](http://www.co2captureproject.org)

The University of Regina has produced a CD on CO<sub>2</sub>-EOR and climate change that it distributes to schools.

During the period of this Mission, Canada was still undecided about ratifying the Kyoto Protocol. The Mission team found that media reporting on the TV and in newspapers was of a high standard and informative, both at the Provincial and Federal level.

### 9.3 Legal Issues <sup>38,40</sup>

As yet, there are no legal frameworks specific to the underground storage of CO<sub>2</sub> in North America. In the USA, environmental legislation surrounding the injection of hazardous substances into the subsurface is controlled by the Environmental Protection Agency (EPA). Of particular concern is the Safe Drinking Water Act (SDWA). The first set of Underground Injection and Control (UIC) regulations under the SDWA were proposed in 1976 and finally promulgated in 1980. With the exception of natural gas storage, which was exempted in the 1980 SDWA re-authorisation, the regulation of underground injection is controlled by the EPA's UIC Program. Implementation is delegated to many States.

In addition, there is a requirement ("Procedures for Decision-Making") that includes public consultation that must be met by UIC Programs. The regulations divide underground injection activities into five major classes. Of interest for geological storage of CO<sub>2</sub> are the following: Class I "Hazardous, Industrial, or Municipal Wells" are managed by State departments of environment or natural resources, while Class II "Hydrocarbon Production Wells" are managed by State conservation commissions or divisions of oil and gas. The explicit goal of the UIC Program is to protect current and potential sources of public drinking water. The movement of injectate into a USDW (underground source of drinking water) is explicitly prohibited, where a USDW is defined as an aquifer that has a total dissolved solids content of less than 10,000mg/litre. The rules mandate zero contamination: If any water quality monitoring for Class I, II, or III (wells which inject for the extraction of minerals, e.g. solution mining for salt) wells demonstrates the movement of any contaminant into the USDW, corrective actions will be taken as are necessary to prevent such movement. However, with the exception of specific Class I hazardous wells, where monitoring can be required, no Federal requirements exist for monitoring USDWs above the injection zone (hence it is possible that movement out of the injection zone will not be detected unless it impinges on human activity or has a surface expression). Since the 1980 regulations were adopted, there have been only four cases of wastewater migration from underground injection wells, and no reported case of USDW contamination from Class I hazardous or industrial wells.

In general, facilities far from population centres are preferred, because they are less subject to local opposition.

### 9.4 Fiscal Regimes to Encourage EOR and ECBM

#### 9.4.1 USA

The current impetus for CO<sub>2</sub>-EOR projects is largely due to fiscal incentives contained in the Crude Oil Windfall Profit Tax Act of 1980 which built upon fiscal incentives introduced in the 1970s as a result of the "oil crises". The main purpose of these incentives has been to address security of supply issues. The legislation preferentially taxed some EOR project profits at 30%, compared with a conventional crude oil profit tax of 70%.

Furthermore, under the Omnibus Budget Reconciliation Act of 1990, which made several changes to capital cost recovery methods, Section 43 of the Internal Revenue Code provides oil producers employing EOR techniques with a tax credit equal to 15% of their qualifying EOR costs. This credit is phased out if oil prices rise above a certain level (\$28/bbl - in 1991 dollars). The value of this tax credit was estimated at \$160 million for fiscal year 1999 or \$245 million in terms of outlay equivalent. The subsidy effectively prolongs the lives of some wells, thus increasing the total volume of hydrocarbons recovered from those wells. In order to be eligible for the credit, the oil producer must employ certain eligible tertiary production methods; miscible CO<sub>2</sub>-EOR is included in this list, as are steam drive injection, micro-emulsion, in situ combustion, polymer-augmented water flooding, cyclic steam

<sup>40</sup> Benson, S. M. et al. 2002: Health, safety and environmental risk assessment for geological storage of carbon dioxide: lessons learned from industrial and natural analogues. Sixth International Conference on Greenhouse Gas Control Technologies (GHGT-6), Kyoto, Japan, 1-4th October 2002.

injection, alkaline flooding, carbonated water flooding and immiscible CO<sub>2</sub> replacement.

The availability of tax credits for non-conventional fuels production under Section 29 of Internal Revenue Code is responsible for much of the growth in production of coal bed methane (CBM) and other qualified alternative fuels, from wells drilled between 1980 and 1992 inclusive, for sales of fuel between 1980 and 2002 inclusive. The value of the Section 29 credit is determined by a formula that varies with the price of oil and inflation. The full value of the credit has ranged from \$0.90-1.08/000ft<sup>3</sup> of natural gas during the 1990s (averaging \$1.02/000ft<sup>3</sup>) and added 53% to the effective price received for eligible production based on the US wellhead price. Most of the companies that generated Section 29 credits did so by producing CBM.

A further source of incentives for both CO<sub>2</sub>-EOR and ECBM is the Pipeline Safety Fund, administered by the Research and Special Programs Administration of the Department of Transportation. This Fund awards grants under Section 5 of the Natural Gas Safety Act of 1968 and the Hazardous Liquid Pipeline Safety Act of 1979 for a range of activities including enforcement programmes, State pipeline safety programmes and R&D. Expenditure from the fund is approximately \$35 million/year.

#### 9.4.2 Canada

As in the USA, fiscal incentives apply to EOR operations to address security of supply. The key legislation is the Oil and Gas Conservation Act. State legislation aligns with this Act.

The EOR royalty and tax system is a cost sensitive system that was designed to recognise the higher investment and operating costs associated with implementing and operating EOR projects. Accordingly, the royalty and tax level is determined on a profitability basis both before and after payout of project investments. The system is applicable to "EOR oil", determined by multiplying the total oil production from each oil well within an EOR project by an "EOR factor" for the project.

A Crown royalty is payable on EOR oil produced from (or allocated to) "Crown" lands. EOR oil produced from CO<sub>2</sub>-EOR projects is subject to different royalty rates than other EOR oil. For CO<sub>2</sub>-EOR projects:

- before investment payout, the Crown royalty equals 1% of gross EOR Crown revenues;
- after investment payout, the Crown royalty equals 20% of Crown EOR income subject to royalty.

For Crown-acquired lands, the production tax rates are the same as the royalty rates specified above applicable to EOR production allocated to Crown lands. For CO<sub>2</sub>-EOR projects:

- before investment payout, the freehold production tax rate equals zero;
- after investment payout, the freehold production tax rate equals 11% of the freehold EOR income subject to tax.

In order for EOR investment costs to qualify under the EOR royalty/tax regime, they must be approved by the Minister as investments directly related to the implementation and operation of an EOR project. Only a portion of the total investments incurred may be considered eligible. Costs such as engineering studies and pre-laboratory or research analysis costs are generally not directly related to a specific project and therefore are not eligible investments. The portion of investment that is eligible under the EOR regime is dependent on the type of investment, i.e.:

(i) Investment specific to oil wells and service wells:

A portion of the investment related to drilling and equipping an oil well, injection well or service well within an EOR project is eligible to be approved as EOR investment. The investments must be made in conjunction with construction of the project or after the project has commenced operation. The portion is determined by multiplying the total expenditure related to the well by the EOR factor for the project. An EOR factor of 100% (in the heavy oil area) means 100% of the well investments are eligible.

(ii) Investment specific to oil cleaning, injection and disposal facilities:

In cases where a facility is handling only fluids produced from the oil wells within a specific EOR project, a portion of the facility investment is approved as EOR investment. The approved portion is

determined by multiplying the total investment by the EOR factor for the project. In cases where a facility is handling fluids produced from the oil wells within a specific EOR project as well as from other projects, or oil wells that are not part of the project, a "Facility Investment Fee" is determined. This fee provides a depreciation component as well as a return on the new investments. This fee is reported as a direct EOR operating cost.

(iii) Investment specific to EOR recovery scheme:

There are certain investments that are required to be made that are specific to the project recovery scheme. Examples of these investments are large capacity steam generators or air compressors. The total of these investments will qualify as EOR investment.

Eligible EOR operating costs include all operating costs that are directly related or attributable to the production of EOR oil. A separate 10% allowance is provided in recognition of overhead and administrative expenses. Examples of direct operating costs include lifting, injection, disposal and general maintenance costs. Crude oil trucking charges are not included as an operating cost because they are deductible in determining the wellhead value of the EOR oil. In a number of cases, both EOR oil and non-EOR oil is produced from an EOR project. For these cases, the direct operating costs that are eligible as EOR operating costs are determined by subtracting the "direct non-EOR operating costs" from the "total direct operating costs" of the project. The non-EOR operating costs are determined by multiplying the volume of oil that is not EOR oil by the "direct non-EOR operating costs factor" that is specified in the regulations. Currently the factor is \$22/m<sup>3</sup>.

In addition to the Federal fiscal scheme, EOR projects in Saskatchewan (excluding waterfloods, which are ineligible) that commenced operation on or after 1 January 1981, are eligible for a Saskatchewan Resource Credit (SRC) under the Crown Minerals Act and the Freehold Oil and Gas Production Tax Act, executed by the Crown Oil and Gas Royalty Regulations and the Freehold Oil and Gas Production Tax Regulations, 1995. The SRC is worth between 1% and 2.5% of EOR production revenue, the higher rate being applied to new or expanded EOR production brought on after 9 February 1998.

## 9.5 Research Positioning and Co-operation

The Mission observed that, in both the USA and Canada, government funding (and broader resourcing) for R&D far exceeded that found in the UK and was much more ambitious. Both the USA and Canada see long term benefits in developing their technologies for a global low carbon future with valuable export markets. The Mission team saw strong ties and alliances between government, academia and industry. It was apparent that UK players are welcome to participate as sponsors in most of these initiatives. UK research collaborators in North American-led projects are generally unable to secure research funding from the North American Federal or State funds, this arrangement is reciprocated in UK and EU led projects. The current EC 6th Framework Programme "Call" presents one of the best opportunities at present to form associate research partnerships. Such arrangements already exist under the EC's 5th Framework Programme (e.g. BGS' involvement in the International Weyburn CO<sub>2</sub> Monitoring and Storage Project).

Canada established a national initiative on CO<sub>2</sub> capture and storage in 1998 and sees itself as taking the world lead in geological sequestration of CO<sub>2</sub>. This is illustrated by its hosting of the IPCC in November 2002 at Regina/Weyburn, its hosting of the "GHGT7" Conference in 2004, and its chairing of the IEA Greenhouse Gas R&D Programme Executive Committee, as well as its active role in the IEA ZETS initiative. Canada has achieved very effective integration of R&D at Federal, Provincial and industrial level. Examples include the Canadian Clean Power Coalition initiative (see Section 4.4.2) and the wide range of organisations and research bodies active in the field, including: the Alberta Geological Survey, the Alberta Research Council, the Geological Survey of Canada (with its National Coal Inventory), Natural Resources Canada, CANMET Energy Technology Center, the Petroleum Technology Research Centre, the International Test Centre for CO<sub>2</sub> Capture and ZECA Corporation.

A selection of the vast array of current domestic and international collaborative initiatives, involving public and private sector partnerships, is highlighted below:

- Canadian CO<sub>2</sub> Capture and Storage Technology Network
- Suitability of Canada's Sedimentary Basin for CO<sub>2</sub> Sequestration
- Sequestration of CO<sub>2</sub> in Alberta's Oil and Gas Reservoirs

- Assessment of CO<sub>2</sub> Storage Capacity of Deep Coal Seams in the Vicinity of Large CO<sub>2</sub> Point Sources in Central Alberta and Nova Scotia
- International Test Centre for CO<sub>2</sub> Capture, University of Regina
- CANMET CO<sub>2</sub> Consortium
- Oxy-Fuel Field Demonstration Project
- Closed Gas Turbine Cycle Project
- ZECA Corporation
- Canadian Clean Power Coalition
- International Weyburn CO<sub>2</sub> Monitoring and Storage Project
- Enhanced Coal Bed Methane Recovery for Zero Greenhouse Gas Emissions
- Acid Gas Re-injection in Alberta and British Columbia
- Sequestration of CO<sub>2</sub> in Oil Sands Tailings Streams
- Geologic Sequestration of CO<sub>2</sub> and Simultaneous CO<sub>2</sub> Sequestration/ Methane Production from Natural Gas Hydrate Reservoirs.

As described in Section 4.2.2 of this report, the United States Department of Energy (DOE) has an extensive Carbon Sequestration Program, which is administered jointly by the Department's Office of Fossil Energy [www.fe.doe.gov/coal\\_power/sequestration/index.shtml](http://www.fe.doe.gov/coal_power/sequestration/index.shtml) and the US DOE's National Energy Technology Laboratory (NETL) in Pittsburgh, PA and Morgantown, WV [www.netl.doe.gov/coalpower/sequestration](http://www.netl.doe.gov/coalpower/sequestration). This programme, and the linkages to the US DOE's "Vision 21" concept (i.e. a high efficiency, sequestration-ready power plant by 2015) is the "centre of gravity" of US activities on CO<sub>2</sub> capture and storage, with the 60 or so projects in the programme's portfolio covering the entire carbon sequestration "life cycle" of capture, separation, transportation, and storage or reuse, as well as research needs for the two other major energy-related GHGs of concern, methane (CH<sub>4</sub>) and nitrous oxide (N<sub>2</sub>O).

A number of clear opportunities for UK organisations or groupings to collaborate with activities in Canada and USA were identified during the course of the Mission: These are reviewed in Section 10.2.

In addition, the Mission team identified a number of issues warranting R&D activities. These included:

- Cost and size reduction for CO<sub>2</sub> capture technologies.
- Increased mineral carbonation rates (i.e. for mineralisation sequestration routes).
- Cost effective long-term monitoring technologies.
- Understanding geological and well integrity with respect to exposure/storage.
- Understanding the effect of pH swings in the subsurface.
- Understanding the geo-mechanical processes associated with CO<sub>2</sub> exposure/injection.
- Enhanced gas recovery (EGR) using CO<sub>2</sub> injectant.
- Offshore application of CO<sub>2</sub>-EOR.
- Optimising reservoir management and modelling.
- Understanding the impacts of potential CO<sub>2</sub> leakage on the biosphere and humans.

## 9.6 Implications and Lessons for the UK

The amount of Government and industrial investment in CO<sub>2</sub> capture and storage technological R&D is very small in the UK when compared with North America, particularly Canada, which has a much smaller GDP and population than the UK.

The Cabinet Office's PIU Energy Review, published in February 2002 (see Section 1) recommended that research into energy technologies be brought under a single umbrella (e.g. an energy research centre and network). This could strengthen and focus the UK's energy research effort, both in the public and private sector. The US DOE, NETL and Natural Resources Canada have clear and ambitious technology and commercialisation "roadmaps" of the way ahead for R&D and demonstration of CO<sub>2</sub> capture and storage over the next two decades. There are short, medium and long-term targets, with significant federal resources allocated, to support these programmes.

The European Commission's 6th Framework Programme recognises the need to strengthen the "European Research Area" in the area of low carbon energy technologies. It has a mixed approach of "instruments" involving integrated demonstration projects, and "networks of excellence". One aim is to align national research programmes within the EU, so as to avoid duplication and achieve maximum gearing across Europe. The UK needs to be ambitious and take full advantage of these instruments in order to harness EC money and be a leader in Europe. Italy is setting such an example, and is

reportedly close to agreeing to fund a €130 million national R&D programme over the next five years that will focus on hydrogen production and CO<sub>2</sub> capture and storage. The UK is the tenth largest oil producer in the world and has the second largest potential underground CO<sub>2</sub> storage capacity in Europe, surely it should build on this opportunity and see its geological assets as a national resource worth investing in.

In the USA, policy incentives to support tertiary oil and gas recovery techniques coincided with the start of the decline from peak oil production. The UK is now similarly placed. Policies to encourage tertiary production ideally need to be developed now, and clear signals of a long term commitment be made in order to enable commercial and investment decisions to be made by the oil and gas operators. In the USA, such policies have been in place for more than three decades. The need for secure and diverse supplies of energy drove the North American initiatives; the case for such initiatives is even stronger when coupled with the prospect of clean energy supplies well before significant alternatives energy sources to fossil fuels are available.

The USA and Canada are clearly aware of the long-term benefits of being technology “leaders” – particularly the large long-term export markets for such technology and know-how (e.g. China, India and SE Asia will all want to use their considerable fossil fuel resources to fuel growth aspirations, but this will require sustainable solutions to address GHG emissions).

North American R&D activity is mainly addressing onshore geological storage. This gives a distinct R&D niche for the UK to address (i.e. offshore storage) which also corresponds to the greatest storage potential.

The UK can become a partner in a range of key US and Canadian R&D activity: These opportunities should be carefully considered.

Canada, particularly, shows close co-operation between industry, research institutes and government departments (including departments with separate responsibilities for industry and environment). This allows a holistic approach to be developed, together with interaction between R&D and regulatory development needs.



## 10 Major outcomes of the Mission

The following sections cover the major outcomes of the Mission – the key messages learned, the opportunities identified for the UK, and finally the recommendations from the Mission.

### 10.1 Key Messages

In both the USA and Canada, the strongly held view is that fossil fuels will continue to be an important part of the fuel mix, and their clean use is clearly being promoted as a key component in the transition to a sustainable energy future. To this end, increased power plant efficiency and the capture and storage of CO<sub>2</sub> are being pursued alongside the development and deployment of renewable energy technologies, leading naturally towards the generation of hydrogen and the prospect of a “hydrogen economy”.

Enhanced oil recovery (EOR) using CO<sub>2</sub> is an established technology in both countries; indeed, West Texas produced its billionth barrel of CO<sub>2</sub>-EOR oil during 2002. There is also over 30 years’ experience of transporting CO<sub>2</sub> in pipelines, to the extent that several million tonnes per year are now carried in a pipeline network of over 3,000km. These volumes and distances are commensurate with those that would be required to develop a CO<sub>2</sub>-EOR infrastructure in the North Sea. Also importantly, large-scale capture of CO<sub>2</sub> is practised under long-term contracts between CO<sub>2</sub> suppliers and users, for example at the Weyburn Project between Dakota Gasification Company and EnCana Resources.

Strong parallels exist between the current position in the North Sea and the situation in West Texas at the time of the 1970s’ oil crises, when EOR was used to boost US oil production. Security of supply, as in the UK now, was then a high-profile issue, and legislation provided the financial incentives to bring on new projects. Importantly, these were long term in nature and necessary to encourage the required investment. Not only was security of supply improved, more jobs were created and a greater contribution made to the GDP.

The USA and Canada are adopting an integrated approach towards fossil fuels and have significant programmes covering CO<sub>2</sub> mitigation from increased efficiency right through to zero emission with CO<sub>2</sub> capture and sequestration. The development of clean coal technologies (CCTs), and their demonstration with CO<sub>2</sub> capture, is seen as crucial, both technically and from an economic standpoint. Both countries are seeking to establish internationally funded, commercial sized demonstration plants based in North America.

The Canadians recognise that it will be necessary to introduce “carbon saving” measures that encourage the take up of new technologies (be they for power generation, or other energy intensive processes using fossil fuels) alongside emissions trading and other policies. It is accepted that any measures must strike a balance between the main drivers: environmental performance, security of supply and industrial competitiveness. There is an understanding that the changes in the market arising from increased deregulation, privatisation and liberalisation do not reward those willing to invest in new technologies. To address this failing, Canada is actively considering setting up a “partnership fund” for the demonstration of CCTs linked to CO<sub>2</sub> capture and storage. This will enable the country to take a strong lead in the international community, building on its work with the IEA Greenhouse Gas R&D Programme, and establishing a project that other countries can join. It is clear that this proactive role will secure benefits to Canada. The USA similarly has aggressive CCT/CO<sub>2</sub> programmes under its Clean Coal Power Initiative (CCPI), Vision 21 and Carbon Sequestration Program.

While technology solutions are being developed, demonstrated and, in some cases, deployed, further technological development and basic scientific understanding must be underpinned by significantly increased research activity in universities and other research institutions. The Mission found an acceptance of the need for high-level co-ordination and integration between industry, government and academia, with evidence already of robust partnerships and networks as both countries seek international co-operation at all levels.

There is also an acceptance of the requirement to develop protocols for CO<sub>2</sub> storage, especially in Canada, which is taking the lead on this and other issues, building upon its chairmanship of the IEA Greenhouse Gas R&D Programme.

Finally, there is evidence in North America of active public awareness schemes resulting in informed public debate and an increased understanding of individual responsibility.

## 10.2 Opportunities Identified for the UK

During the Mission, a number of opportunities were identified for possible UK collaboration or involvement with both the USA and Canada. These are at several levels and of different types. It should be noted that there is a UK-USA agreement on fossil energy (under a 10 year Memorandum of Understanding between the US DOE and the UK DTI covering energy research), due to be formally signed in early 2003. It looks likely that CO<sub>2</sub> capture and storage will be key areas identified and targeted for co-operation activities under this agreement.

### 10.2.1 Technology Collaboration

Opportunities for technology collaboration, identified by the Mission team, ranged from the exchange of information to joint research projects and involvement in demonstration projects.

For research activities and technology acquisition, some of the potentially important opportunities are as follows:

- Involvement with the US DOE R&D activity through programmes such as the President's Coal Research Initiative and the Carbon Sequestration Program.
- Joining the club-based research led by the International Test Centre (ITC) for CO<sub>2</sub> Capture at the University of Regina investigating post-combustion CO<sub>2</sub> capture technologies (amine scrubbing, membranes, etc.) at its pilot facility in Regina and the associated pre-commercial pilot plant at Boundary Dam Power Station near Estevan, Saskatchewan.
- Joining the collaborative activities led by CANMET Energy Technology Centre (CETC) investigating oxy-fuel firing developments as a route to CO<sub>2</sub> capture using its pilot facilities in Ottawa.
- Maintaining an active UK involvement (through the DTI and BGS) in the R&D activities associated with the International Weyburn CO<sub>2</sub> Monitoring and Storage Project as subsequent phases/work programmes/R&D projects develop.
- Maintaining an active UK involvement (through the DTI) in the Alberta Research Council and CETC-Devon's pilot scale work on ECBM as subsequent phases/work programmes/R&D projects develop.
- Developing links with the Petroleum Technology Research Centre (PTRC) in Regina, on the optimisation of CO<sub>2</sub>-EOR and ECBM recovery.

For demonstration activities, the key opportunities identified included:

- Involvement with the US DOE demonstration activities through collaborating with industrial consortia in programmes such as the Clean Coal Power Initiative, Vision 21 and the regional partnerships and showcase demonstrations expected under the Carbon Sequestration Program.
- UK government involvement (through the DTI) in any international CO<sub>2</sub> capture and storage pilot/demonstration projects that emerge from discussions with the US Government and other countries due in mid-2003.
- Joining the Canadian Clean Power Coalition and thereby gaining access to a programme to develop two CO<sub>2</sub> capture demonstration projects – a retrofit of either amine scrubbing or oxy-fuel firing technology planned for 2007, and a "greenfield" gasification-based demonstration plant planned for 2010.
- Joining ZECA Corporation to participate in the demonstration of its hydrogasification/calcining and solid oxide fuel cell based cycle concept as a route to zero emission hydrogen and/or electricity.
- Involvement with Kinder Morgan and Elsam on the CENS Project (CO<sub>2</sub> for EOR in the North Sea).
- Maintaining an active UK involvement (through the DTI and BGS) in the demonstration of CO<sub>2</sub> storage associated with the International Weyburn CO<sub>2</sub> Monitoring and Storage Project as subsequent phases/work programmes develop.

### 10.2.2 Policy and Economic Issues

Opportunities for collaboration on economic and policy-related issues were also identified by the Mission team. Some of the potentially important opportunities are as follows:

- Continuing involvement with both the IEA Greenhouse Gas R&D and Clean Coal Centre Programmes, together with an active role in the IEA Working Party on Fossil Fuels and its Zero Emission Technology Strategy (ZETS) initiative.
- Initiating an investigation of least-cost routes for pre-combustion CO<sub>2</sub> capture at large scale and assessment of advanced capture concepts together with the US DOE, CETC and such organisations as ZECA Corporation, etc.
- Involvement with Natural Resources Canada (through CETC) in the Canadian lead on the development of international CO<sub>2</sub> storage protocols.
- Initiating techno-economic/resource strategy studies for the application of CO<sub>2</sub>-EOR and CO<sub>2</sub> storage in the North Sea utilising the approach developed by the Canadian Energy Research Institute (CERI).

### 10.3 Recommendations from the Mission

It is recommended that the UK should develop an integrated carbon management strategy that encompasses a portfolio approach, including fossil fuels, renewables, and possibly new nuclear. For fossil fuels, this means addressing CO<sub>2</sub> mitigation from increased efficiency (in both generation and use) right through to (near) zero emission power plant with CO<sub>2</sub> capture and storage.

It is increasingly recognised that the clean use of fossil fuels, including CO<sub>2</sub> capture and storage, will be critical in the transition to a sustainable energy future. In this context, it is recommended that cost reduction of capture technologies should be addressed and that storage options in the North Sea be identified and optimised.

It is recommended that enhanced oil recovery with CO<sub>2</sub> injection be used to extend the life of the North Sea oil reserves. Not only would this yield significant incremental oil production and improve the UK's security of energy supply, it would also stimulate a market for CO<sub>2</sub>. Financial incentives are required for this to happen; these must have a long duration to ensure that there is sufficient confidence to invest in the infrastructure required in the North Sea. It is widely recognised that there is a window of opportunity in the next decade, after which it will be difficult to take any such initiative forward.

There is a need to ensure that the UK is at the forefront and able to take advantage of the opportunities in carbon management. It is recommended that an implementation plan should be developed on an urgent basis. This would need to involve the oil and gas, power generation and other industrial sectors, together with Government and, where appropriate, the research base. From this, it should be possible to identify the potential for a UK-based, internationally funded demonstration project that complements those found elsewhere.

In this context, the strong lead taken by Canada in the development of a protocol for CO<sub>2</sub> storage needs to be supported, so that the interests of the UK in offshore, sub-sea storage are properly represented at the international level. Also, it is recommended that the UK take an active part in the international activities already underway, both at a research and industrial level.

All these actions need to be part of the recommended long-term strategy for carbon management involving a greater co-ordination between the different governmental and private funding bodies, between the different parts of industry, between the different parts of the research community and, importantly, between them all. The development of technology and commercialisation "roadmaps", backed by deployment studies, will considerably help this process. It is clear that technological innovation will continue to be critical in meeting future energy demands and environmental needs at an acceptable cost.

Increased public awareness and acceptance of the issues will be essential.



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## Appendix C

### Mission questions:

#### CO<sub>2</sub> Capture

- Capture technologies available.
- Outstanding R&D on these technologies.
- Viable power generation solutions for CO<sub>2</sub> capture (covering newer technologies, such as IGCC, through to retrofitting of pf plant).
- Operational issues.
- The amount of CO<sub>2</sub> each technology can capture, as against illustrative estimates of that required to meet UK targets under, say, Kyoto.
- The quality of the CO<sub>2</sub> needed and the processing required to make it usable.
- The issues around storage on site or immediate transport.
- Processing of the CO<sub>2</sub> prior to end-use (e.g. drying, compressing, etc.).
- Economics (i.e. capital costs, operating costs, project economics).
- International perspective.
- Incentives.
- The likelihood that power generators will be prepared to install CO<sub>2</sub> capture equipment.
- The potential for hydrogen as a viable side product from IGCC.

#### CO<sub>2</sub> Transport

- The costs of the various means of transportation to the storage site (i.e. by pipeline, tanker or both).
- The planning issues associated with pipelines.
- The technical issues concerning the integrity of the CO<sub>2</sub> in transit (the level of any background leakage and the risks and environmental consequences of sudden release CO<sub>2</sub> due to component failure).
- Environmental and planning issues around transportation of the gas from the power generators to the storage site.

#### CO<sub>2</sub> Storage/Use

- The legality of CO<sub>2</sub> storage - the use of CO<sub>2</sub> as a working fluid, e.g. for EOR, versus sequestration.
- Geological aspects - will the CO<sub>2</sub> stay down in the ground?
- Leakage from sealed bore holes (e.g. due to CO<sub>2</sub> interaction with the concrete plug) or via other possible geological routes.
- The possibility of sudden leakage. Effective monitoring. Probabilistic risk analysis. Catastrophic failure.
- Social issues: Public concern over storage underground; the possibility of the disastrous consequences of leakage; storing up a problem for the future.
- Engineering and technical issues. Such issues surround the technology to inject the CO<sub>2</sub> into wells, either for storing or for EOR. Corrosion issues and other metallurgical issues and the overall risk of component failure need to be identified and assessed to contribute to the risk analysis already discussed.
- Economics (e.g. the cost per tonne of CO<sub>2</sub> saved, comparing this with other low or zero emission technologies, the impact CO<sub>2</sub> capture and storage will have on the costs of generation and the price of electricity which will be needed to make its capture attractive compared with other sustainable forms of power generation (conventional as well as renewable)).

- The impact of EOR on the attractiveness of CO<sub>2</sub>. To determine if it will be enough to establish an infrastructure such that later, when the CO<sub>2</sub> is for storage only, costs could be economic.
- The impact of an emissions trading scheme, which gives a value to CO<sub>2</sub>. Would it provide a sufficient incentive for investment?
- Risk and environmental issues around the offshore and onshore storage of CO<sub>2</sub>. The use of CO<sub>2</sub> for EOR. The benefits and issues of using CO<sub>2</sub> from fossil fuel generation for this.
- The geological issues around CO<sub>2</sub> storage. The reliability of the CO<sub>2</sub> staying underground. The risk/probability of leakage to the atmosphere. Slow versus catastrophic leakage. Identify reserves suitable for CO<sub>2</sub> storage.
- The options for storage offshore. Underground storage onshore. The possibilities for ECBM production.
- The engineering issues surrounding the transport of CO<sub>2</sub> from production location to storage site, and injection underground (either offshore or onshore).
- International relations - the concerns of other countries whose coastline runs along any sea which is considered for storage.
- The need for inventory methods which would be acceptable under the UNFCCC and Kyoto Protocol.

### **CO<sub>2</sub> Infrastructure Issues**

Additional to the issues for the three components above, there are overarching infrastructure issues that need to be assessed. These are:

- The market in CO<sub>2</sub> covering the interaction of CO<sub>2</sub> producers (power generators, oil companies and other industries that produce large quantities of CO<sub>2</sub>), transporters (pipeline companies or gas transporters) and consumers/storage.
- In the case of EOR, the adequacy of the quantities of CO<sub>2</sub> collected with that required for EOR at any given time. Also the quality of the CO<sub>2</sub> for oil recovery.
- The overall economics of fossil fuel power generation with CO<sub>2</sub> capture and storage, versus other energy technologies.
- Will the various technologies for capture, transport and storage work together?

## Appendix D

### Dissemination seminar summary:

**DTI Conference Centre, 1 Victoria Street, London, 15 January 2003**

#### Introduction

This report provides a summary of the Dissemination Seminar that followed the UK's Mission to the USA and Canada on CO<sub>2</sub> capture from power plant and geological storage with enhanced oil/coal bed methane recovery options. The report gives an overview of the seminar presentations and of the discussion sessions. It closes with a summary of the concluding views from the leader of the Mission who was also the seminar chairman.

The seminar was very well attended with approximately 110 delegates. These delegates consisted of: R&D workers in the field, strategy and technology managers, representatives of funding agencies and policy makers. Representatives were present from universities and industry, including the supply chain and the oil/gas industry.

#### Seminar objectives

This Dissemination Seminar was a key dissemination activity for the Mission and it was designed to help a wide variety of organisations improve their strategic thinking in this rapidly developing area. In particular, delegates were expected to benefit from:

- improving awareness of activities in the USA and Canada (world leaders in this area);
- opportunities for developing collaboration and technology transfer;
- insights into UK opportunities for CO<sub>2</sub> capture and storage both on- and off-shore;
- gaining a better idea of the costs involved; and
- relevant information on environmental risk analyses.

The seminar consisted of overview presentations from the leader of the Mission, the Department of Trade and Industry, Canada and the USA. This was followed by presentations from the UK participants in the Mission covering the main areas of interest. There were also discussion sessions on each area of interest, which allowed the delegates to raise questions or to express their own views. The programme for the seminar is given as an Annex to this Appendix.

#### Background and overview presentations

The first two presentations were given by Nick Otter, chairman of the Advanced Power Generation Technology Forum (APGTF) and leader of the Mission and Philip Sharman of the DTI's International Technology Promoters Programme - jointly responsible for the Mission with the DTI arranging and funding the Mission and the APGTF leading it.

Nick Otter gave an introduction to the APGTF which provides the focus for the power generation sector in the UK on the research and development activities on fossil fuel, including biomass and waste and associated technologies including carbon sequestration. He then explained the background and objectives of the Mission and linked these to the increasing concerns over greenhouse gases with the desire for a sustainable energy future. This leads into the issue of how to use fossil fuels cleanly. The UK has two particular drivers that could make CO<sub>2</sub> capture and sequestration particularly attractive: the potential for using CO<sub>2</sub> for enhanced oil recovery (EOR) in the North Sea and a very large underground capacity for CO<sub>2</sub> storage. The Mission focused on technology issues with research and development, demonstration and deployment being addressed. It also covered social and political issues.

Philip Sharman introduced the DTI's International Technology Service, which helps the UK to identify and learn from leading organisations and technologies from around the world. It organises approximately 30 missions a year and 80 secondments a year, all with the objective of learning from the world's best.

### Policy issues and initiatives in USA and Canada

The first of these presentations was an invited presentation from Frank Campbell of CANMET, Energy Technology Centre - Ottawa, which is part of the Federal Department of Natural Resources Canada. Carbon capture and sequestration has been identified in Canada as a part of their response to the Kyoto Protocol. Canada has a large potential for CO<sub>2</sub> storage underground together with potential for enhanced coal bed methane (ECBM) production and enhanced oil recovery (EOR). CANMET undertakes management and funding of energy R&D programmes as well as undertaking R&D itself. The issues being investigated for capture and storage are: capture costs and efficiencies; storage reliability and effectiveness; and, legal and social issues. An overview of the key R&D projects was presented; further details are given in the Mission report.

As well as managing and participating in R&D for the sector, CANMET are also involved in drawing up national technology roadmaps which are part of a 25 year plan. Co-operation is seen as key and a lot of emphasis is placed on social issues, particularly education of the public.

The US Department of Energy also provided a presentation on perspectives from the USA but unfortunately the speaker from the USA was unable to attend; instead, Nick Otter gave the presentation. The DOE has a number of related programmes and initiatives on aspects of carbon capture and sequestration, which cover all the issues from R&D through to demonstration and infrastructure. CO<sub>2</sub> intensity reductions of 18% are targeted for the next 10 years (measured as tCO<sub>2</sub>/unit of GDP) with economic growth being sustained. The budget for the Carbon Sequestration Program is growing with a budget of around \$40 million anticipated for 2003. Included in these programmes is support for projects on increasing plant efficiency – this is in marked contrast to the EU, which is not supporting such projects. There is also the Vision 21 concept, which is targeting pollution free fossil plant by 2015. Part of the DOE's initiative is to support the development of spin-off technologies to help give industry a strong position in global markets.

Brian Morris of the DTI, who was on the Mission, then gave his perspective of the policy issues and activities in the USA and Canada; details of this part of his talk, which was closely linked to the previous USA and Canada presentations, are given in the Mission report. Of particular interest was the comparison that was made with the position in the UK. One significant difference is that the main oil and gas reservoirs that could be used for storage are under the North Sea, whereas in most of North America, particularly Canada, they are on land. This means that the costs for CO<sub>2</sub> storage in the UK will be higher. The main lessons learnt were given as: recognition of the importance of regulation and fiscal incentives; the need for strong industrial partnerships; international co-operation is essential; a clear strategy is needed with defined goals; and, the importance of public education and awareness.

The details contained in all the following presentations are given in the Mission report so only key points are reported here.

### CO<sub>2</sub> Capture

Tony Howard of Powergen gave a presentation on post-combustion capture. He gave technical and economic details of all the technologies being investigated in Canada and the USA and he commented that they are well ahead of initiatives in the UK. He also made the point that in the UK, as in the USA and Canada, there is currently no business case for a generator to get involved with these technologies; for this to change, the right business drivers will be needed from government.

The oxy-fuelling approach was presented by Andy Timms of Mitsui Babcock; this is seen as an alternative approach to post combustion scrubbing and pre-combustion decarbonisation. It does have the possibility of being a retrofit option. This technology is being investigated in the USA and Canada as well as in the UK, principally at Mitsui Babcock. Oxy-fuelling is seen as viable and is in need of a demonstration. There could be real benefit to the UK by involvement with the Canadian initiatives.

David Hanstock of Progressive Energy gave the talk on pre-combustion decarbonisation, which mainly refers to gasification technologies. Capture technologies are either chemical solvents, physical solvents or membranes. Some of these technologies are already commercially proven and demonstrated at large scale. In the UK this would be associated with future, new plant; and, so far two UK, full-scale gasification projects have been proposed, both of which could have capture technologies integrated.

## Discussion

In discussion there were questions on the reliability, availability, maintainability and operability ("RAMO") of these technologies, which has become a crucial issue for power plant owners. All the speakers said that high levels of RAMO had already been demonstrated or were being designed in.

There was some discussion on the viability of any retrofit demonstration for existing pulverised fuel fired plant in the UK, particularly if it was to be linked to EOR in the North Sea, which has a limited window of opportunity that a retrofit demonstration could miss. The supporters of this approach said it would be feasible to build this now, but the issue is cost.

There was some discussion on target efficiencies for coal plant. Typical targets for the medium term are 60% efficiency. The consensus was that to achieve this, it would probably be necessary to go to gasification-based technologies. In the short to medium term, pf would continue its dominance, particularly if the global market was being considered.

The point was made that longer term, the strategy could be a progressive shift to the "hydrogen economy" and fossil fuels would be expected to have a key role in this.

## CO<sub>2</sub> transport, sequestration and utilisation

Nick Riley of the British Geological Society gave a presentation on CO<sub>2</sub> transport infrastructure. The USA has many miles of high-pressure pipeline from naturally occurring CO<sub>2</sub> sites and industrial sources for use in EOR. They have an excellent safety record and are seen as world leaders in CO<sub>2</sub> pipelines.

Issues concerning the long-term geological storage of CO<sub>2</sub> were also presented by Nick Riley. Natural underground CO<sub>2</sub> stores show that geological storage can lock the gas away for a very long time. The main types of storage that are being considered are: saline aquifers; operating as well as dis-used hydrocarbon reservoirs; coal seams; and, mineral carbonisation. A key part of the R&D effort is to assess the risks associated with man-made storage, e.g. leakage and pollution.

Enhanced oil recovery activity in the USA and Canada was presented by Philip Sharman of the DTI. EOR is a major activity in both USA and Canada with CO<sub>2</sub> injection becoming more important. The technology is regarded as well understood, but the economics tend only to be viable because of favourable fiscal frameworks. In order to get maximum benefit, it is important to understand the geology and miscibility.

A presentation on enhanced coal bed methane production was given by Brian Ricketts of UK Coal. This relies on coal's greater affinity for CO<sub>2</sub> compared to methane, the adsorption characteristics and permeability of coal being crucial. Both Canadian and UK coals are suitable. Canada has a 60mtCO<sub>2</sub>/year gap in its strategy for reducing CO<sub>2</sub> and ECBM has the potential to contribute to this reduction. Current testing is at the small, pilot-scale, with a full-scale continuous production test planned for 2005.

In discussion there were several questions and comments about EOR applied in the UK. At the moment the costs are too high and the right fiscal regime or other incentive is needed to make it economic. When EOR is commenced typical breakthrough times in the US are 3-6 months, however for the North Sea this is likely to be more and could be as long as 18-24 months. (Future Energy Solutions are carrying out a study on EOR in the UK for the DTI).

With regard to ECBM, it was commented that UK coals are gassy but with low permeability, which will mean lots of wells. It is not regarded currently as feasible economically for offshore coal seams. There was some discussion about potential synergy between ECBM and underground coal gasification, but the conclusion was that it was probably a "long shot".

## CO<sub>2</sub> social, legal and research issues

Nick Riley gave a presentation covering these topics. He noted that there was a wide social acceptance of CO<sub>2</sub> capture and sequestration and this even extended to pride in the vicinity of active sites. In Canada there had been a high quality public debate on the Kyoto Protocol. In North America, all CO<sub>2</sub> activities are onshore, yet there is no legal framework in place specific to underground storage without EOR.

There was some discussion on the different public perception of the onshore oil/gas industry in the UK and North America where pride and social acceptance are not found in the UK to the same extent as in America.

Several points were made concerning research issues and strategy relevant to the UK:

- There are not many outstanding technical issues for EOR but there are for ECBM.
- There was a consensus amongst the speakers that emphasis on energy efficiency and management were essential in the short to medium term.
- A mixed portfolio approach is needed to reducing CO<sub>2</sub> emissions, with renewables, nuclear and carbon sequestration all being needed.
- More emphasis will be needed on educating the public and gaining acceptance.
- There are several opportunities for collaboration with the USA and Canada and the USA has already listed several countries, including the UK, it would like to discuss collaboration with.

### Summary and outcomes

Nick Otter, the leader of the Mission, presented the key messages and recommendations that had come from the Mission. The key messages are:

- Fossil fuels continue as an important part of the fuel mix.
- Both Canada and the USA are linking clean coal technology demonstration with CO<sub>2</sub> capture and storage.
- There is an accepted need for high co-ordination and integration between industry, government and academia.
- There is an accepted requirement for a protocol covering CO<sub>2</sub> storage.
- Existence of active public awareness schemes is key.
- EOR using CO<sub>2</sub> is an established technology.
- Financial incentives are critical in promoting EOR.

The recommendations for the UK are:

- Establish a long term strategy for carbon management.
- Ensure greater co-ordination and integration of UK energy research, development and demonstration.
- Introduce correctly targeted market-based measures and incentives for technology take-up.
- Establish a CO<sub>2</sub>-EOR route as a basis for CO<sub>2</sub> storage.
- Work up the case for demonstration of clean fossil fuel power plant technologies with carbon capture.
- Urgently address the CO<sub>2</sub> storage protocol issue.
- Establish an active public awareness programme.

## Annex to Appendix D

### CO<sub>2</sub> Capture and Storage Mission Feedback Seminar Programme

Wednesday 15 January 2003

DTI Conference Centre, London

#### PROGRAMME

##### CO<sub>2</sub> MISSION BACKGROUND AND OVERVIEW

Introduction and Overview of Mission	Nick Otter, ALSTOM
Initiatives of DTI's International Technology Service	Philip Sharman, DTI - ITP

##### CO<sub>2</sub> POLICY ISSUES AND INITIATIVES IN USA AND CANADA

Perspectives from USA	Nick Otter, ALSTOM
Perspectives from Canada	Frank Campbell, CETC - Ottawa
Perspective from UK	Brian Morris, DTI

##### CO<sub>2</sub> CAPTURE

Post-combustion Capture	Tony Howard, Powergen
Oxy-fuelling Approach	Andy Timms, Mitsui Babcock
Pre-combustion Decarbonisation	David Hanstock, Progressive Energy

##### CO<sub>2</sub> TRANSPORT, SEQUESTRATION and UTILISATION

CO <sub>2</sub> Transport Infrastructure	Nick Riley, British Geological Survey
Long Term Geological Storage	Nick Riley, British Geological Survey
Enhanced Oil Recovery	Philip Sharman, DTI - ITP
Enhanced Coal Bed Methane Recovery	Brian Ricketts, UK Coal

##### CO<sub>2</sub> SOCIAL, LEGAL and RESEARCH ISSUES

Social, Legal and Research Issues	Nick Riley, British Geological Survey
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##### SUMMARY and OUTCOMES

Summary of Benefits, Conclusions and Recommendations	Nick Otter, ALSTOM
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