Evaluating Carbon Dioxide Capture and Storage Technology Options with an Energy-Economy Model

by

Averil J. Lamont

B.Sc., University of Victoria, 2000

A RESEARCH PROJECT SUBMITTED IN PARTIAL FULFILLMENT
OF THE REQUIREMENTS FOR

THE DEGREE OF MASTER OF RESOURCE MANAGEMENT

in the School
of
Resource and Environmental Management

Project no. 346

SIMON FRASER UNIVERSITY
November 2003

APPROVAL

NAME: Averil Lamont

DEGREE: Master of Resource Management

REPORT NO.: 346

TITLE OF RESEARCH PROJECT Evaluating Carbon Dioxide Capture and Storage Technology Options with an energy economy model.

EXAMINING COMMITTEE:

Mark Jaccard

Associate Professor
School of Resource and Environmental Management
Senior Supervisor

John Chad Day
Professor Emeritus
School of resource and Environmental Management
Supervisor

Date Approved: Friday, November 14, 2003

PARTIAL COPYRIGHT LICENCE

Title of Thesis/Project/Extended Essay:

Evaluating Carbon Dioxide Capture and Storage Technology Options with an Energy-Economy Model

Author:

(Signature)

Averil J. Lamont

November 21 /2003
(Date Signed)

ABSTRACT

Carbon dioxide (CO_2) capture and storage technologies, which allow for the capture of CO_2 from fossil-fuel-burning power plants and long-term storage in saline aquifers, provide an alternative of a de-carbonated economy rather than the complete replacement of our fossil fuel based economy with renewable technologies. While Canada is well situated to benefit from such technologies—we have several large saline aquifers in close proximity to large CO_2 emitters—uncertainties exist regarding the capital and operating costs of such technologies, the geological attributes of storing CO_2 in saline aquifers, and the societal response to such technologies. This research reviews these uncertainties, develops a series of scenarios to reflect the range of the uncertainties, and determines the potential economic consequences of these scenarios using CIMS, an energy-economy model.

Results from the assumptions used in this study reveal that: (1) CO_2 capture and storage technologies may be implemented through the retrofitting of existing technologies; (2) these technologies were out-competed by renewable technologies in competing for new energy markets and that no new fossil-fuel-burning power plants or greenfield plants would be constructed; (3) the cost of achieving an emission reduction target for Canada of 181 megatonnes (Mt) of CO_2 varied from 164 to 176 \$/t of CO_2 reduced, depending on the cost of CO_2 capture and storage; and (4) in all scenarios, capture and storage technologies accounted for at least 27% of the total reductions achieved in the electricity sector.

LIST OF ACRONYMS

AEEI	Autonomous Energy Efficiency Index
AMG	Analysis and Modelling Group of the National Climate Change Process
ASU	Air Separation Unit
CIMS	Canadian Integrated Modelling System
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide or equivalent (includes all other GHG's)
CO_2 C&S	Carbon Dioxide Capture and Storage
E/Q	Energy Intensity
ESUB	Elasticities of Substitution
FGD	Fluid Gas Desulphurization
GHG	Greenhouse Gases
GHG/E	Greenhouse Gas Intensity - amount of Greenhouse Gases produced per unit of energy consumed)
GtC	Giga Tonnes Carbon
H_2SO_4	Hydrogen Sulphate
IGCC	Integrated Gasification Combined Cycle
IPCC	Intergovernmental Panel on Climate Change
MEA	Monoethanolamine
MgO	Magnesium Oxide
NG	Natural Gas
NGCC	Natural Gas Combined Cycle
NOx	Nitrates
P	Population
PFBC	Pulverized Fluid Bed Coal
Q/P	Economic Output per Capita
SOx	Sulphates
Syngas	Synthetic Gas

ACKNOWLEDGEMENTS

I would like to thank Dr. Mark Jaccard for giving me the opportunity to pursue this project. The brief time that I spent working with the Energy and Materials Research Group has enriched my professional career immensely. A particular thanks to Dr. John Nyboer, Chris Bataille, Bryn Sadownick, and Rose Murphy for taking the time to help better structure my research project and to answer my numerous questions about the model.

A special thanks to my husband Grant for his continued support throughout my research and for challenging me to ask more questions, stretch my knowledge, and believe in myself.

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

1.0 Introduction

Humanity's increasing combustion of fossil fuels is releasing large amounts of greenhouse gases (GHG's) into the atmosphere. This increase in atmospheric GHG's is believed to be causing increased atmospheric temperatures and global climate change. In response to this problem many developed nations signed the Kyoto Protocol, calling for the reduction of Annex One[1] Countries' anthropogenic carbon dioxide (CO_2) emissions to 5.2% below 1990 levels (Kyoto Protocol 1997, A.3). While climate change mitigation options have primarily focused on replacing our energy intensive fossil fuel based economy with a fully renewable, less energy-intensive economy, industry and governments are exploring additional options.

One of the new options being explored involves the capture of CO_2 from fossil fuel driven power stations and its subsequent storage in saline aquifers. Canada is well situated to benefit from these due to the large number of potentially suitable aquifers that are in close proximity to large CO_2 emitters. However, uncertainty exists regarding the economic costs of facility construction, the geological feasibility of storing CO_2 in saline aquifers, and societal response to the storing of CO_2 underground. This project addresses the question: how do these uncertainties, which directly and indirectly influence the cost of CO_2 capture and storage technologies, influence the costs for Canada in meeting our Kyoto targets?

---

[1] Annex One Countries refers to signatory countries that have made GHG reduction commitments. These countries include industrialised countries as well as some countries formerly in the Soviet sphere of influence.

1.1 Increasing Greenhouse Gases – Science and Political Response

Increasing concentrations of GHG's, including CO_2 and methane (CH_4), prevent heat from leaving the atmosphere, leading to such problems as: increased temperatures, sea level rise, increased storm frequencies, and changes in rainfall patterns (IPCC 2001). The Intergovernmental Panel on Climate Change (IPCC) concluded that most of the observed warming over the last 50 years is likely (60-90% certain) to have been due to the increase in human-produced greenhouse gas concentrations (IPCC 2001).

The international community responded to this problem by creating the IPCC and responding to the initial IPCC report (1990) by signing the United Nations Framework Convention on Climate Change (UNFCC 1992). The details of how the UNFCC goals are to be achieved are outlined in the Kyoto Protocol, a legally binding agreement under which Canada was to achieve a 6.0% reduction of 1990 CO_2 emission levels by 2008-2012 (Kyoto Protocol 1997, Annex B). While Canada ratified the Protocol in December of 2002, the USA has continued to insist that they will never ratify the agreement. However, if Russia ratifies the protocol, as they declared to do at the World Summit on Sustainable Development, the protocol threshold of 55 countries accounting for at least 55% of 1990 Annex One emissions will be reached and the protocol will then come into effect (Kyoto Protocol 1997, A.25.1).

1.2 Options for Reducing Greenhouse Gases

The possible options by which governments can achieve their Kyoto targets are outlined by the Kaya Identity (a special type of decomposition equation) (Jaccard, Nyboer, and Sadownik 2002). This equation helps to explain how changes in greenhouse gases are related to specific factors. The Kaya Identity states that:

$$\%\Delta GHG = (\%\Delta GHG/E)(\%\Delta E/Q)(\%\Delta Q/P)(\%\Delta P)+\%\Delta GHG \text{ captured and stored}$$

- where:

- GHG = greenhouse gas emissions
- E = unity energy
- Q = measure of economic output
- P = population

The options that the Kaya Identity presents for various nations to reduce their GHG emissions include:

- Reducing population,
- 2) Reducing total economic output per capita (Q/P),
- 3) Reducing energy intensity of the economy (energy efficiency or E/Q),
- 4) Reducing GHG intensity of energy (fuel substitution or GHG/E), and
- 5) Capturing and storing GHG's from the atmosphere or industries that release a high concentration of GHG's into the atmosphere.

The first two options of reducing population and reducing total economic output per capita are currently not considered due to perceived social constraints. However, changes in economic output per capita may occur due to changes in energy prices and the pricing of greenhouse gas emissions. Previous research indicates that CO_2 sinks and storage, energy intensity reductions, and reducing greenhouse gas intensity of fuels through fuel switching all play a role in reducing greenhouse gases (Jaccard, Nyboer, and Sadownik 2002). However, reducing the energy intensity of the economy may be offset by the rebound effect which states that increases in energy efficiency of a product result in an increase in energy and material use (Cleveland and Ruth 1999). Reducing the GHG intensity of energy requires the development of low GHG intensity energy sources such as wind and solar power. This involves major expenditures or technological breakthroughs to ensure commercial availability, leaving the fifth option of capturing and storing already emitted GHG's from the atmosphere or from fossil fuels. Possibilities included in this option are the enhancement of carbon sinks, such as forests, arctic tundra, wetlands, and soils, or the capture and burial of carbon in the ocean or geological formations.

A carbon sink is defined as any process, activity, or mechanism which removes a GHG, an aerosol, or a precursor for a GHG from the atmosphere (IPCC 2001). Carbon sinks are usually divided into two groups: oceanic and terrestrial. While the use of ocean sinks is uncertain due to the low level of knowledge surrounding oceanic responses to increased levels of CO_2 (US DOE 1999), the enhancement or use of terrestrial carbon sinks including the arctic tundra, forests, wetlands, and soils is difficult to measure and faces competition from other potential land uses (Reimer and Omerod 1995). For Canada to meet its commitment to the Kyoto Protocol by 2012, other options, such as CO_2 capture and storage, are being considered.

1.3 CO_2 Capture and Storage

The process of CO_2 capture and storage, also known as CO_2 capture and sequestration, prevents carbon from entering the atmosphere through CO_2 being extracted, concentrated, and transported to a site for long-term storage (IPCC 2001). The first and most expensive stage of this process involves the energy-intensive separation and capture of carbon-based molecules from other molecules. Several options have been proposed for the second or storage stage including geological formations and the deep ocean. Ocean storage of CO_2 could possibly result in small changes in the biogeochemical cycles of the planet (US DOE 1999). The high level of uncertainty associated with these changes has made this option less attractive than the alternative, geological formations.

There are several possible geological formations that could serve as storage locations or reservoirs for captured CO_2 including saline-aquifer formations, enhanced oil and gas reservoirs, methane-containing coal beds, and depleted oil and gas reservoirs (Doherty and Harrison 1992). The technology needed to take advantage of these options is already developed and commercially available in enhanced oil and gas recovery operations. However, due to the limited availability of sites for enhanced oil and gas recovery and also the low percentage of CO_2 trapped over the long term, the total storage area available in enhanced oil and gas reservoirs is small (Gunter et al. 1998). This leaves CO_2 storage in saline aquifers as the favoured option for long-term CO_2 storage, since saline aquifers are both widely available and have a high capacity for CO_2 storage. The estimates for total storage of CO_2 in open aquifers with cap-rock formations (an impermeable rock formation that traps CO_2 within a sedimentary layer of an aquifer) range from 2,700, and13,000 GtC (Giga tonnes of carbon) (Williams 2002). Both of these estimates are significantly greater than the 1,500 GtC estimate of the total GHG emissions produced for the period of 1990 to 2100, which is based on the IPCC generated IS92a model (IPCC 2001).

It is for these reasons, of technological feasibility and high-storage capacity, that an alternative carbon-management future has been proposed, a future that involves the storage of CO_2 in saline aquifers.

1.4 Canada, and CO_2 Capture and Storage

The impact of CO_2 capture and storage technologies on Canada's ability to meet its Kyoto obligations was first reviewed as part of the Canadian National Climate Change Process (NCCP). Started in 1998, the role of the NCCP was to examine the impacts, costs, and benefits of implementing Kyoto (NCCP 2001). Sixteen sector and issue-based working groups selected by government and comprised of representatives from academia, industry, and non-governmental organizations outlined various alternatives in options papers. These papers were then consolidated and integrated into different analyses by the Analysis and Modelling Group (AMG). The CIMS model[2] was one of two energy-economy models used by the AMG to determine the ability of different alternatives to reduce GHG's and the impact of these alternatives on Canada's economy. CIMS indicated that 43% of the total emissions reductions required to meet Canada's National Target could be achieved in the electricity sector and over 35% of this reduction would be due to one CO_2 capture and storage technology (Jaccard, Nyboer, and Sadownik 2002). The impact of the availability of this technology on Canada's ability to meet Kyoto was tested in this report; decreasing the availability of CO_2 capture and storage facilities was observed to reduce the amount of CO_2 emissions achieved, increase the permit price, and increase the total cost of achieving emissions reductions (Table 1.1).

---

[2] The CIMS model, initially developed in 1986, has been under continuous development by the Energy and Materials Research Group (EMRG), at Simon Fraser University.

Table 1.1 Sensitivity of Permit Trading Price and Total Cost of meeting Kyoto to the availability of CO2 Capture and Storage Technologies (Nyboer, Jaccard, and Sadownik 2002, 91, by permission)

Availability of Technology	Share of Electricity Emission Reductions	Displaced Reductions (Mt CO_2e*)	Permit-trading price ($/t CO2e)	Total cost (billions $-1995)
Full	35%	0	120	44.7
Half	17.5%	13.5	127	45.0
None	0%	27	135	47.7

* $MtCO_2e$ – Mega tonnes (1000 tonnes) of CO_2 and equivalent greenhouse gases (includes CO_2 emissions as well as methane emissions)

In the 2002 Climate Change Plan for Canada, initiatives supporting the implementation of CO_2 capture and storage technologies account for a reduction of 10.2 Mt from Canada's GHG emissions (CANADA 2002). The implementation of clean coal technologies could increase this estimate, potentially capturing an additional 50Mt of CO_2 per year (CANADA 2002).

However, these claims require further analysis due to the uncertainty surrounding Canada's capacity to store CO_2, the economic costs of building and maintaining CO_2 capture and storage facilities, and societal responses to these technologies. The two basins currently being considered for CO_2 storage—the Alberta and Williston Basins—(Figure 1.1) only contain a few aquifer-exploring wells, making a comprehensive assessment of the storage capacity and movement of fluids within these basins difficult (Fisher, Sloan, and Mortensen 2002).

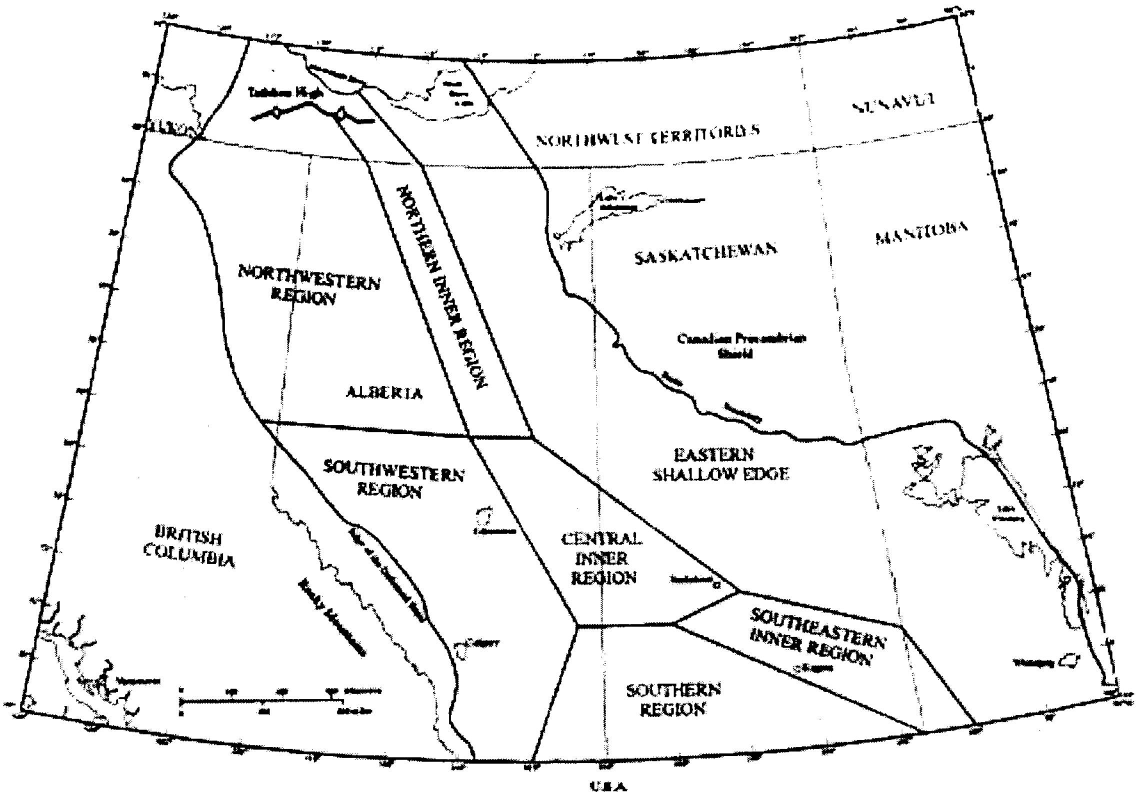

Figure 1.1 Map of the Western Sedimentary Basin, including the Williston (southern region) and Alberta (northwestern and southwestern regions) Basins (Fisher, Sloan, and Mortensen 2002, 78, by permission)

The cost of constructing a CO_2 capture and storage facility in Canada has not yet been determined, as no capture facility has ever been built. While the over $1 billion Saskatchewan Weyburn Project provides insights into the capture, transport, and storage of CO_2 in enhanced oil-recovery operation, injection of CO_2 into a saline aquifer has only been attempted in the North Sea at the natural-gas-extracting Sleipner T Platform. The recently announced Canadian Clean Power Coalition's $5 million feasibility study for the construction of Canada's first clean coal power plant will provide insights into these uncertainties. However, all of the costs for building such a facility will not be fully understood until a full-scale demonstration facility is built. The Canadian Clean Power Coalition is expecting to accomplish this by 2007. To the present time, the economic costs for capturing CO_2 from a fossil-fuel burning power generation unit and subsequent storage in saline aquifers remains uncertain, as does societal response to such an initiative.

The purpose of this research is to:

1. Examine selected uncertainties associated with the geological feasibility, economic costs, and societal response to CO_2 capture and storage technologies.
2. From this research develop a series of cost scenarios that reflect these uncertainties.
3. Evaluate these scenarios using an energy-economy model to determine how uncertainties associated with the geological feasibility, economic costs, and societal response to CO_2 capture and storage technologies impact Canada's ability to reduce GHG emissions.

2.0 Types of CO2 Capture and Storage Technologies

This study examines three different electricity generation technologies, which include CO_2 capture and storage technologies and thus have the potential to reduce GHG emissions. Due to technical differences, different types of CO_2 capture technologies are best suited to each individual power generation process (Chapel, Ernest, and Mariz 2001).

2.1 Coal Power Plant

The most common large-point source to which CO_2 capture can be applied is the coal power plant. In a coal-fired facility, coal is milled and then combusted in a steam generator unit in the presence of air (component one, Figure 2.1). This produces high-pressure steam which is run through a steam turbine (component two) to generate power. The resulting flue gas is then treated to remove first fly ash and second sulphur (components three and four). Fly ash is separated using a regenerative air heater and an electrostatic precipitator, while flue gas desulphurization (FGD) occurs using a wet-limestone mixture. Following these two steps, the remaining flue gas is released to the environment via a smokestack.

It is possible to add a third removal or separation stage to this process, one that removes and concentrates CO_2. The least-expensive and best-studied option for doing this in a coal-fired power plant is by scrubbing the flue gas with monoethanolamine (MEA), an amine-based solvent (Marion et al. 2001). In this process, the CO_2 molecules become bound to MEA molecules in the absorber. These bound CO_2-MEA molecules next enter the CO_2 stripping unit, where the MEA- CO_2 molecules are separated from the rest of the flue gas and then re-heated to separate the MEA from the CO_2. The MEA molecules are then recycled back to the absorber where they repeat the process, while the CO_2 is cooled and compressed for transport.

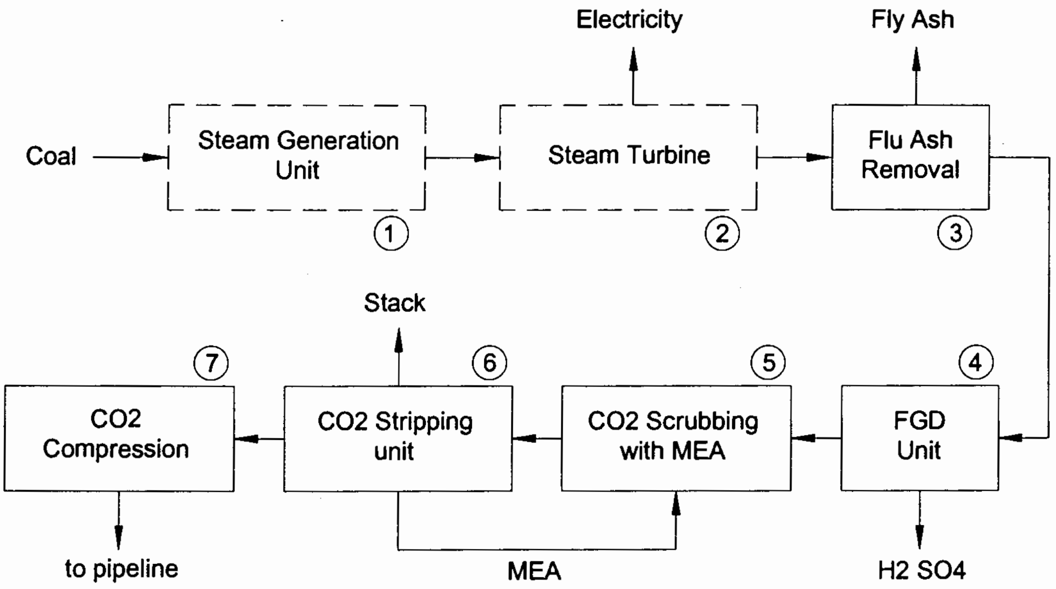

Figure 2.1 Flow diagram for CO_2 separation from a coal power plant by MEA, the solid boxes represent the newly added or modified components for the CO_2 capture system.

However, the use of MEA for CO_2 capture poses some design constraints. They include:

- fly ash interacting with MEA in the CO_2 separation unit causes foaming, erosion, and corrosion as well as degradation of the MEA compound;
- MEA reacts irreversibly with sulfur forming a salt compound which is unable to bind to CO_2 molecules;
- MEA is easily degraded by high temperatures;
- carbon steel ducting that transports the flue gas and the MEA compound can be corroded by oxygen, especially in a hydrogen-sulfide-free-environment; and

- MEA regeneration requires a large amount of energy to successfully strip CO_2 from the MEA molecule (Marion et al. 2001; Booras and Smelser 1991).

To overcome these potential problems, additional equipment beyond the basic absorption, stripping, and compressor unit should be included in a CO_2 capture facility.

To reduce the amount of fly ash in the flue gas, an air heater and electrostatic precipitator are added just before the flue gas desulphurization unit. The electrostatic precipitator creates a high-voltage electric field using two electrodes; one electrode is usually a pipe or flat plate while the other is a wire axially suspended in the centre of the pipe or two plates. Charged dust particles move from the strong part of the field (the wire) towards the weak part of the field (either the pipe or plates), thus separating the fly ash from the remainder of the flue gas (Rapier et al. 1996).

For the desulphurization process, it was determined that the cost of reducing the SOx concentration in flue gas to 10 ppmv (parts per million volume) prior to CO_2 removal equals the cost of replacing the amount of MEA that irreversibly binds to SOx (Booras and Smelser 1991). In order to achieve this low concentration of SOx, the traditionally-used wet-limestone process must be replaced with a magnesium-pebble limestone. Scrubbers, which improve the contact between the Magnesium Oxide (MgO) and the suspended SOx particles within the flue gas, aid in the recovery of SOx particles. As part of the MgO process, SOx particles are converted to H_2SO_4 which can be used by the agricultural industry.

Following fly ash removal and desulphurization, the remaining flue gas is cooled to ensure MEA temperature degradation does not occur. The flue gas is then transferred to the CO_2 absorber where inhibitors are added to the flue gas to prevent oxygen in the flue gas from corroding the metal ducting. The CO_2 bound MEA is then sent to the associated stripper where low pressure steam re-boils the solution causing the MEA to release CO_2. The remaining MEA is cooled and then recycled to the absorber so it can be re-used. Heat-stable solvents (degraded MEA) are removed using a solvent re-claimer, and make-up MEA is added as needed.

Because the flue gas has such a low concentration of CO_2—between three, and thirteen percent—MEA is one of the few chemical solvents active enough to recover such dilute CO_2. However, the drawback of this is that it requires much energy (40% of steam flow) to regenerate MEA, or strip CO_2 from it (Marion et al 2001). For many facilities this low-pressure steam cannot be extracted from the existing turbine and thus the turbine is replaced with two units, the back-pressure turbine that generates low-pressure steam and a condensing turbine which generates electricity.

Auxiliary power is also required to run the distribution system as well as the CO_2 compressor (CO_2 Compression and Liquefaction). There are three stages involved in compressing CO_2: first, CO_2 is compressed to 790 psia; second, the compressed CO_2 is dried; and finally it is further compressed to 2200 psia. The CO_2 is cooled to reduce the amount of water vapour within the captured CO_2 stream, which is of concern due to the cooling of the compressed gas during transport and the highly corrosive nature of CO_2 when free water is present.

The now liquid CO_2 is ready for transport. However, the additional power required for auxiliary power and MEA regeneration results in an energy penalty of 35% over a plant without CO_2 capture. Despite this heavy energy penalty, the use of the MEA absorption-stripping process is still considered the most efficient (David 2000). This is due to MEA's high CO_2 loading factor; two moles of MEA are needed for each mole of CO_2 (Erga and Olsen 1991).

2.2 Natural Gas Combined Cycle

In the second application of CO_2 capture and storage, the highly–thermal-efficient natural gas combined-cycle power plant (NGCC), natural gas is combusted in a gas turbine with air (Chapel, Ernest, and Mariz 2001). The waste heat from this combustion process is then captured and used to drive a second turbine for additional power. The MEA absorption process (Figure 2.1) used in capturing CO_2 from coal can also be applied to natural-gas-fired, combined-cycle power plants. However, the lower carbon-to-hydrogen ratio in natural gas results in a 3-3.5% concentration of CO_2 in the flue gas, which is at the lower end of the MEA solvent's CO_2 binding range. For this reason, MEA is not as efficient at binding to CO_2 as it is in coal-fired power plants (Bolland and Saether 1992). The lower concentration of CO_2, following separation of CO_2 from the flue gas, leads to higher energy cost due to an increased need to compress the flue gas prior to transport (Bolland and Saether 1992). Also, because the CO_2 scrubbers in the separation unit require a lower gas velocity for optimum operation, more scrubbers must be installed to accommodate the high volumetric flows in the natural gas plant (Bolland and Saether 1992).

2.3 Integrated Gasification Combined Cycle (IGCC)

Integrated-gasification, combined-cycle power plants (IGCC) convert coal to a synthetic gas (syngas), composed primarily of hydrogen and carbon monoxide, in an oxygen-blown gasifier (component two, Figure 2.2). This syngas is then combusted to drive a combustion turbine (component nine). Heat generated from these first two stages is then use to drive a secondary steam turbine (component eleven) (Doctor, Molburg, and Thimmapuram 1997). In the first stage a cryogenic air separation unit provides oxygen (component one); ash is removed from the gasifier through slagging, which occurs when molten ash particulate comes in contact with a surface, becomes chilled, and solidifies (component three). Following ash removal, COS hydrolysis converts the remaining syngas, primarily COS (carbon monoxide sulfide), via gasification into hydrogen sulfide, and carbon monoxide (component four).

The syngas is gasified a second time in a shift reactor producing primarily to produce a primarily hydrogen and CO_2 syngas (component five). A two-stage Selexol (glycol-based compound) process is then applied, first to remove hydrogen sulfide (component six), and second to remove CO_2 (components seven and eight). The two systems are integrated, with the hydrogen-sulfide-free solvent from the hydrogen sulfide stripper being sent to the CO_2 absorber. Because of this integrated process, regeneration of the solvent (Selexol) is not required, thus reducing the energy consumption of this process relative to the MEA CO_2 removal process.

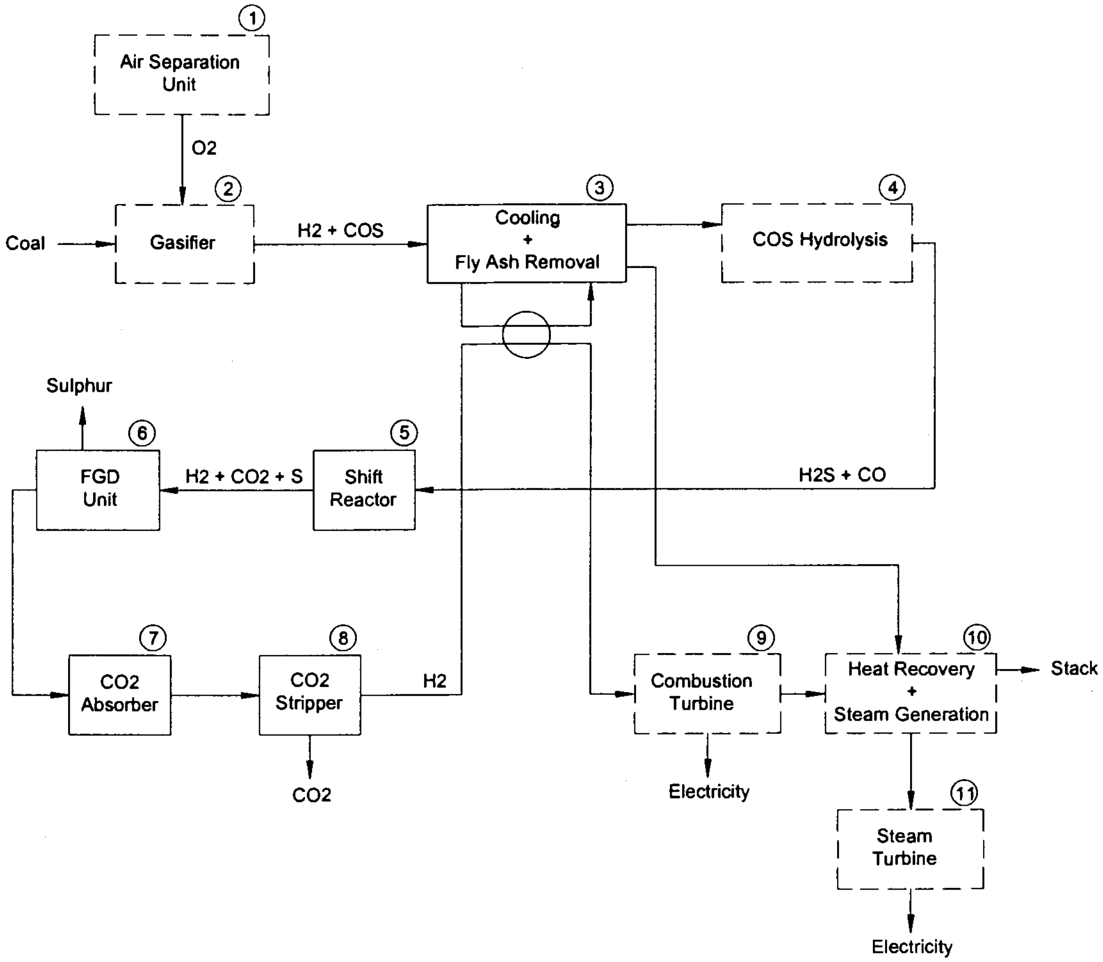

Figure 2.2. Flow diagram for the integrated gasification combined cycle (IGCC) plant with CO2 removal.

Following these removal stages, the primarily hydrogen syngas is combusted in steam turbine for power generation. Waste heat created from the initial gasification step and from the combustion turbine is used to drive a secondary steam turbine, creating more energy. While the isolation of CO_2 in the IGCC process is more capital intensive due to the costly and energy-intensive gasifier and cryogenic air separation unit (ASU), this is offset by the lower cost of coal relative to natural gas as well as the lower cost of the physical solvent relative to the chemical solvent (MEA) (Williams 2001).

The advantages and disadvantages of all of these capture processes are presented in Table 2.1. Following each of these three capture processes, the captured CO_2 is compressed and transported, by pipeline, to a saline aquifer for long-term storage.

Table 2.1 Description and comparison of the various CO_2 capture processes discussed in this paper.

Power Plant Type	**Storage Type**	**Advantages**	**Disadvantages**
Simple Cycle Coal (Coal)	MEA absorption—stripping process	1. MEA's high CO_2 loading factor	1. reacts irreversibly with sulfates 2. very volatile and corrosive
Natural Gas Combined—Cycle (NGCC)	MEA absorption—stripping process	1. NGCC process is most energy efficient	1. low concentration of CO_2 in flue gas leads to increased use of compression 2. increased use of scrubbers 3. lower efficiency of MEA
Integrated Combined—Cycle Power Plants (IGCC)	Physical Absorption—Pre-combustion glycol-based stripping process (Selexol)	1. Not as corrosive as MEA 2. Option to sell hydrogen 3. IGCC is almost as energy efficient as NGCC 4. air pollutants as low as NGCC 5. easier solid waste management than coal	1. base technology price is higher as IGCC is a new technology 2. higher cost of gasifier and air separation unit—costs more than NGCC—MEA process

3.0 Methodology

Predicting the future costs and market penetration of any new technology is uncertain and understanding the impact of a new technology on the environment and economy of a nation is even more so. In an attempt to explore different possible futures for CO_2 capture and storage technologies, an energy-economy model is used to describe how different future trajectories for CO_2 capture and storage technologies influence the GHG intensity of energy in the Canadian economy.

This chapter begins with a discussion of the benefits of using an energy-economy model to evaluate GHG emissions reducing technologies. This is followed by a description of the three types of energy-economy models and how CIMS, the model used in this study, fits into this framework. Next, is a discussion of the existing literature regarding the modelling of costs and implementation of these technologies and how this project adds to this literature. The portrayal of technologies within CIMS is then discussed to aid the reader in understanding why particular attributes of CO_2 capture and storage technologies are focused on in the development of different future scenarios.

3.1 Energy-Economy Models

Climate policy analysts often use energy-economy models to understand the impacts that a particular policy might have on the GHG intensity of energy (GHG/E) and the intensity of energy use (E/Q) within a particular economy (Jaccard, Nyboer, and Sadownik 2002). Energy-economy models are ideal for this task because they reflect the interplay between energy systems, economic growth, demographic changes, climate change mandate, and technological progress (Bosello, Carraro, and Kemfert 1998). This interplay is usually represented through the analysis of how technological decisions affect GHG/E and E/Q and how policies can alter these decisions, in turn altering the emissions produced by a particular economy (Edmonds, Roop, and Scott 2000). By analysing a wide range of future scenarios for CO_2 capture and storage technologies in an energy-economy model, climate analysts would gain a better understanding of the influence that technological uncertainties have on both GHG/E and E/Q within a particular economy.

There are generally two different types of energy-economy models discussed in the literature: top-down models and bottom-up models. Top down models typically derive their cost estimates from market observations of firm's and household's responses to changes in energy costs. These historical data are then used to predict how firms and households will respond to future changes in energy costs (Hourcade and Robinson 1996; Edmonds et al. 2000). In top-down models the rate of technological change is calculated using two exogenously generated indicators--the index of autonomous improvements in energy efficiency (AEEI) and price-consumption relationships often referred to as 'elasticities of substitution' (ESUB). While AEEI describes the rate at which energy productivity improves as a result of price-independent technological evolution, ESUB values specify the substitutability between aggregate inputs (capital, labour, energy, and materials) and between energy forms (Jaccard et al. 2003). It is the generation of these two indicators from historical relationships that draws the most criticism from bottom-up modellers. Their argument is that historical relationships can not accurately indicate future consumer preferences for new technologies due to: the dynamic nature of the economy; changing government policies leading to falling technological costs (particularly in research and development); and changes in consumer preferences (Jaccard et al. 2003). By relying on a historically based AEEI, and not including a high level of technological detail, top-down models are unable to represent future technological options (Azar and Dowlatabadi 1999). A further problem with top-down models arises from the baseline assumption, that the current state of the market represents economic efficiency and that any change in policy will result in a loss of consumer welfare. Because of these assumptions top-down models often overestimate the cost of adopting new technologies.

Bottom-up models, traditionally used by engineers and systems analysts, determine changes in energy use and emissions reductions through the increased diffusion of alternative energy technologies. Technologies are represented within bottom-up models by their financial costs and efficiencies. Within this type of model, consumer preferences are often overlooked, resulting in the full cost of switching being based solely on financial costs. However, technologies with similar financial costs are not always viewed as being perfect substitutes by consumers (Jaffe and Stavins 1994; Jaccard et al. 2003). Some technologies may be viewed as riskier than others due to unknown future reliability. Many new technologies also require high up-front investment costs, while future benefits of reduced operating costs are uncertain due to fluctuating energy costs. Because of investment irreversibility, there may be value, sometimes referred to as option value, in firms waiting for further information before making a decision to invest (Jaccard et al. 2003). Also, two technologies that may appear identical to an engineer may not be perceived as identical to the consumer. For example, in comparing incandescent and florescent bulbs, consumer value for fluorescent bulbs may be lower than incandescent ones due to unattractiveness of fluorescent bulbs or a perceived decrease in the quality of light (Jaccard, Nyboer, and Sadownik 2002). Finally, not all households or firms face the same capital, acquisition, installation, and operation costs, as these can vary from location to location. A further criticism of bottom-up modelling is its decreased ability to incorporate economic feedbacks needed to evaluate the macroeconomic effects of government policies. Many bottom-up models only achieve partial equilibrium within one economic sector, or a subset of economic sectors, due to the high number of technologies competing within each sector. Because policies directed at one sector can have impacts in other sectors, the effect of a particular policy on a targeted sector may not be adequately portrayed if full equilibrium feedbacks are not present within the model (Jaccard et al. 2003). By overlooking consumer preferences, and not achieving full equilibrium feedbacks, bottom-up models tend to underestimate the cost required to achieve greenhouse gas reductions.

3.2 CIMS Model

However, there is a third type of energy-economy model that combines the technological detail of a bottom-up model with the consumer preferences and equilibrium feedbacks of a top-down model. Models that include these three components are generally referred to as hybrid energy-economy models; CIMS (formerly the Canadian Integrated Modelling System) is one such model. The CIMS model is based on a bottom-up model, containing detailed listings of technologies for six different economic sectors

(Industrial, Electricity, Transportation, Residential, Commercial, and Other) in six of Canada's provinces plus an amalgamation of the Maritime Provinces. Economic feedbacks are incorporated into the model with the use of energy-service elasticities and integrated supply and demand feedbacks between energy-using and energy-producing sectors. CIMS also includes consumer preferences of both firms and households for various technologies available within the model. These preferences are obtained, in part, from discrete choice models, or stated or revealed preference surveys.

Using CIMS, a hybrid energy-economy model, to evaluate future scenarios of CO_2 capture and storage technologies, and their impact on GHG/E intensity, adds to the current discussion surrounding these technologies in several ways. Past research of these technologies includes numerous first-generation or engineering-based analyses, which evaluate the cost of implementing a CO_2 capture and storage facility in a particular location (David 2000); and several top-down analyses, which evaluate the role of these technologies in the international community (Dooley et al. 2002) and in the United States electricity markets (Johnson and Keith 2001). However, no hybrid model has yet been used to evaluate the role that capture and storage technologies might play in the Canadian economy, given different future-cost trajectories. Furthermore, analyses conducted with top-down models of the United States economy have not included competition with nuclear or renewable technologies, nor equilibrium feedback between different sectors of the economy (Johnson and Keith 2001).

3.2.1 CIMS Components

CIMS various components reflect its hybrid nature. Technological explicitness is reflected in both the energy-supply and energy-demand components of the model (Figure 3.1). The energy supply and conversion component includes all the technologies that either supply energy to the economy, or convert energy into different forms, including Natural Gas (NG), Oil, Coal, Renewables, Oil Processing, and CO_2 capture and storage technologies, among others. The energy-demand component is comprised of all the technologies found in the energy-using sectors of the economy, which includes the industrial, commercial, residential, and transportation sectors. It is through the numerous technologies of these two components that technological explicitness is included in CIMS. Consumer and firm preferences are also included at the technological level.

In the macroeconomic component of the model, price elasticities are used to calculate the shift in energy-services demand as the price for that technology or service changes. A low elasticity indicates that a plant can sustain its sales in the face of a cost increase, while a high elasticity suggests the opposite (Lipsey, Purvis, and Steiner 1991). It is these price elasticities that give CIMS the ability to incorporate equilibrium feedbacks. However, these effects are limited to the economic system; economic impacts could also occur from changes in climate, just as the climate is impacted by changes in the economy (Jaccard, Nyboer, and Sadownik 2002).

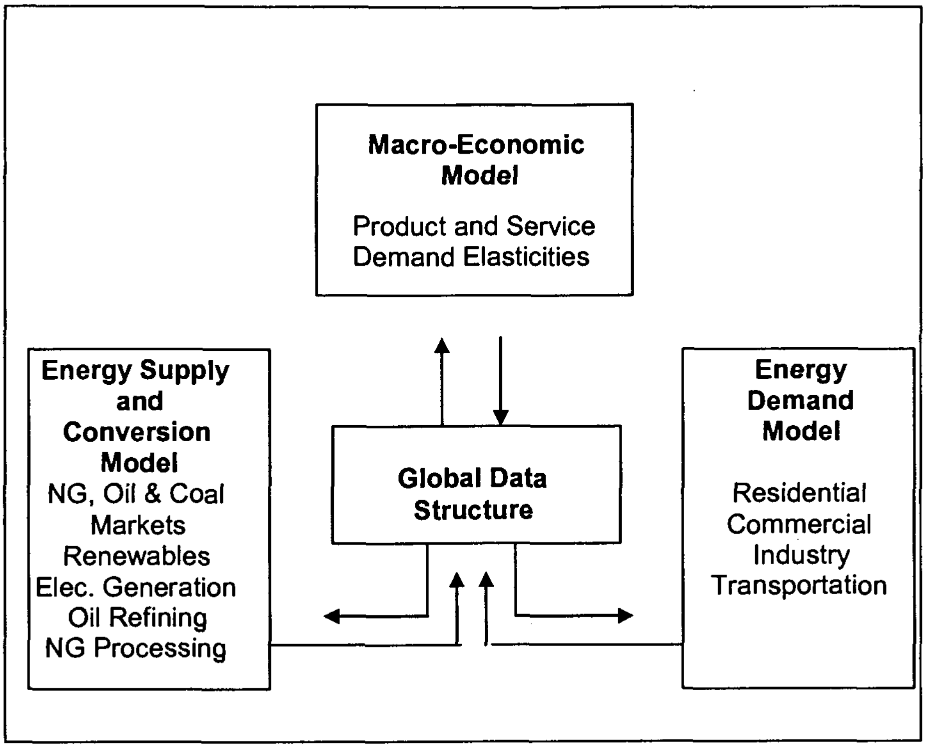

Figure 3.1. Flow diagram of CIMS Structure (Jaccard, Nyboer, and Sadownik 2002)

3.2.2 CIMS Simulation

The CIMS simulation procedure is as follows:

1. An externally produced macroeconomic forecast, based on data from Natural Resources Canada, provides initial fuel prices, demand for energy services, industrial throughput, economic growth, and population growth data, that drive each five-year time period.
2. In each five-year period existing equipment is retired. While most retirement is time-dependent, premature retirement—or retrofitting—of existing equipment may also occur. This usually happens when a particular technology is deemed to be economically obsolete. The difference between demand for technologies and the total stock remaining is calculated and new technologies are brought on line if necessary.

3. Technologies compete to capture market shares of the new equipment. The capture of market share is determined by the relative financial costs and technology-specific preferences of firms and households.
4. For each time period, the model iterates between the supply and demand components until energy prices and demand stabilise. Stabilization is defined as a less than 5% difference between one iteration and the next.
5. For each time period, the model cycles through the macroeconomic component to determine if changes in the cost of providing services and products has resulted in changes, via services elasticities, in their demands. Depending on the size of a response, the model may iterate back through the demand and service components until an equilibrium is reached.
6. At the end of each five-year period the following are calculated: energy consumption by fuel type, GHG emissions produced for both the energy supply and demand components, and the incremental costs of a policy option above the business as usual case.
7. The impact of the changes in the cost of energy services, and the demand for these services on the economy and overall economic growth, is then determined through the macroeconomic feedback loop.

3.2.3 Technology Competition

CIMS portrays technological change by simulating the turnover of equipment based on financial costs and the preferences of businesses and consumers. Specified technologies within a sector such as electricity supply or residential, are arranged within a flow model. Whenever an increase in demand for a given service occurs, or a technology is retired or retrofitted, technologies compete for this new market share. This competition occurs at a particular node in the flow model, within the particular sector in which new technologies are required. The portion of the market captured by a particular technology is a function of the life-cycle cost ($ per unit of service provided) of that particular technology relative to the technologies against which it is competing (Equation 3.2.1).

Equation 3.2.1

$$MS_{kt} = \frac{LCC_{kt}^{-v}}{\sum_{k=1}^{z} LCC_{kt}^{-v}}$$

- where:

  MS_{kt} = market share of technology k for new equipment stocks at time t,

  LCC_{kt} = annual life-cycle cost of technology k at time t,

  v = variance parameter,

  z = total number of technologies competing to meet service demand.

The market share function (MS_{kt}) is a logistic relationship between the life-cycle cost of a given technology and all other technologies that compete to fulfil the same service demand. Life-cycle costs ($/GJ of power provided in the electricity sector) are based on the capital, operating, and energy costs, as well as other performance parameters for a particular technology (Equation 3.2.2). The cost of GHG emissions are included in this equation in the policy simulation.

Equation 3.2.2

$$LCC_{kt} = \left(\frac{CC_{kt} \times \dfrac{r}{1-(1+r)^{-n}}}{SO_k} \right) + O_{kt} + E_{kt}$$

- where:

CC_{kt} = capital cost of technology k at time t,

SO_k = annual service output or energy produced by technology k,

O_{kt} = operating cost of technology k at time t per unit of service output,

E_{kt} = energy cost of technology k at time t per unit of service output,

r = discount rate (time preference)

n = equipment lifespan

Other factors, outside of financial costs, also influence technology competitions. These factors include the variance parameter (v), the discount rate (r), intangible cost factor (i_{kt}), and the declining capital cost function (Jaccard, Nyboer, and Sadownik 2000).

The variance parameter (v) represents market heterogeneity, which arises from differences in fuel costs, technology differences, installation costs, and information availability. These differences may result in a consumer or firm selecting what appears to be a less desirable technology when purchasing a new technology. Within CIMS the v parameter, determined through expert judgment, is applied to the single-point life-cycle cost converting it into a probability distribution (Wiebull Distribution). A probability-based calculation then allocates market shares as a function of the degree of overlap between competing technologies. Because the v parameter is often the same across a given sector of the economy (i.e. all electricity sector technologies have a v parameter of

10), the smaller the v parameter, the narrower the life-cycle cost probability distribution and the greater the market share captured by the cheapest technology (Jaccard et al. 2003).

The discount rate (r) reflects the preferences of firms and households to the riskiness of new technologies as well as the irreversibility of investing in new technologies with long lifespans. In CIMS the discount rates come from market data or through extensive industry consultations (Jaccard, Nyboer, and Sadownik 2002). However, the discount rate in CIMS can be applied across the entire economic sector; this is done when capital costs are restricted to the ex ante financial cost of equipment acquisition and installation, and r is set at the social discount rate. The resulting life-cycle cost represents the conventional value used in bottom-up analysis. The CIMS user can also choose to specify a different value for r for every technology competition. Capital costs for each technology can also be defined to include an intangible cost, i_{kt}, that represents estimated option-value costs and/or consumers' surplus losses associated with a technology relative to its prime competitor (Jaccard et al. 2003). It is this second method that is used in this particular study, with the discount rate for all capture and storage technologies set at twenty percent.

Intangible costs (i_{kt}) included in the calculation of capital costs for a technology, are meant to reflect the intangible character difference that exists between competing technologies. Intangible costs are included in calculating capital costs for a given technology (Equation 3.2.3) when there is an indication that a particular technology is valued more by a consumer or firm (Jaccard, Nyboer, and Sadownik 2002).

Equation 3.2.3

$$CC_{kt} = FC_{kt} + i_{kt}$$

- where:

FC_{kt} = financial cost of technology k at time t

i_{kt} = intangible cost factor of technology k at time t

The higher the value for r, the greater the competitive disadvantage for technologies with a higher capital-to-operating-cost ratio. The higher the value of i_{kt}, the greater the competitive disadvantage for a technology (Jaccard et al. 2003).

A declining capital-cost function is also included within CIMS. This asymptotic function cause capital costs to decline in response to increased production of a new technology as indicated by market share (Jaccard et al. 2003).

3.2.4 Retrofitting Function

In the case of retrofitting, which is when an existing technology undergoes a modification to reduce its GHG emissions, the competition for market share of the retrofitted technology is slightly different from the new-stock competition. The life-cycle cost of retrofitted technology or technology that is to be upgraded is calculated using the operating cost and energy cost of the technology; the life-cycle cost for retrofitting technologies includes the capital cost of the retrofitted portion of a facility in addition to its operating and energy costs. These life-cycle costs are then multiplied by a randomly selected point on the Weibull distribution, which for retrofits has a variance parameter of 0.4 to reflect market heterogeneity. This is in contrast to the variance parameter of 10 which is used in the new market-share calculation. In the electricity sector two technologies, the shoulder-load and base-load single-cycle coal facilities are both able to be upgraded through the retrofitting function.

4.0 Scenario Development

Predicting the future cost of a new technology is uncertain. Understanding the impact of a new technology on the environment and economy of a nation is even more so. By developing a series of future cost scenarios for CO_2 capture and storage technologies that take into account a wide range of cost predictions, potential environmental impacts, and social concerns and analysing these scenarios in CIMS, the impact that these scenarios might have on Canada's ability to reduce greenhouse gases are examined.

Because the objective of scenario development is to provide the decision-maker with a series of plausible, interesting, distinctive, and understandable alternatives (Lanford 1972), several different scenarios were designed. The theoretical underpinning of these scenarios, and the cost and performance parameters required for CIMS, are discussed in the following sections.

4.1 Base Case Scenario

CO_2 capture and storage technologies are of interest to both government and industry because they potentially provide a cheaper option for reducing Canada's GHG emissions. However, these technologies are not in existence at a level for which future costs can accurately be predicted; Canada's first full-scale plant is expected to be completed in 2007 (Fisher, Sloan, and Mortensen 2002). To date, cost estimates for these technologies have focused on either the scaling up of smaller versions of food or fertilizer grade CO_2 capture facilities, or on a variety of engineering analyses (Bolland and Saether 1992; Booras and Smelser 1991; Marion et al. 2001). This section outlines the average costs, taken from these studies, and the performance parameters needed to incorporate

CO_2 capture and storage technologies in CIMS, including: the capital costs for construction, the amount of energy for operation, the yearly non-energy operating costs, the facility's CO_2 output, and the cost of transporting and storing CO_2 captured from such a facility. These costs are then related to the projected electricity output over a plant's lifetime, arriving at a unit cost per kilowatt of net electricity output (Lanford 1972). In using any energy-economy model to evaluate different technologies, it is important to remember that the output can only be as reliable as the expectations concerning the input costs as well as the economic parameters adopted for the assessment (NEA-OECD 1992).

4.1.1 Capture Stage

The cost for each of the CO_2 capture processes reflect the different advantages and disadvantages (Table 2.1) associated with each technology (Table 4.1). Costs vary for each of these technologies depending on the capture process used, the plant size, and the fuel source (David 2000). Regardless of the process used, additional energy is required for both stripping CO_2 from the fuel or flue gas and CO_2 compression. This leads to increased energy demand by these facilities and ultimately increased costs.

Data for the three CO_2-capture- and-storage-including power-plant facilities (Coal, NGCC, and IGCC) are drawn from fourteen different studies which are summarize in Jeremy David's comprehensive survey (2000). Given the wide range of costs discussed in the fourteen studies, the average is adopted for the base-case scenario for this project. Capital costs, operating costs, and CO_2 output are translated into a cost per unit of power output ($/kW) for each facility. Relative power output, or the energy efficiency of a particular facility, is listed as the percentage of power available to consumers relative to the total power produced by the facility. Total cost of electricity is also listed, even though it is not included in the energy-economy model, and is based on an annual capital charge rate of 15% and energy prices of 1.30$/GJ for coal and 3.09$/GJ for natural gas (David 2000).

Table 4.1 The costs of three different power generating systems, which include CO_2 capture facilities.

Capture Process	Coal – MEA	NGCC – MEA	IGCC – syngas
Capital Cost ($/kW)	2571	1168	2265
Operations and Maintenance Costs ($/kW)	15.7	5.1	11.6
Carbon Output (kg/kWh)	0.105	0.042	0.088
Relative Power Output	31%	48%	36%
Total Cost of Electricity (c/kWh)	7.71	4.91	6.69

[a] Costs are all in Canadian Dollars

Based on available data in the literature, it appears that NGCC facilities, using a MEA process for capturing CO_2 from flue gas would be the most economical option. However, it is important to also consider transportation and storage costs, which may be influenced by the type of capture facility.

4.1.2 Transport and Storage Stages

The projected costs of transporting CO_2 from a capture facility to a storage site are dependent on distance and topography as well as the quantity of CO_2 transferred (Wildenborg 2000). While distance and topography determine the length of pipeline required to transfer CO_2, the materials used to build the pipeline are determined by the chemical properties of CO_2. Traditional materials used for oil and gas pipelines would corrode if they were to be used for CO_2 transport. Despite the material requirements for a new pipeline, reductions of transportation costs are possible through economies of scale; the larger the amount of CO_2 transferred and disposed of at a given site, the lower the cost per unit of CO_2 transported (Figure 4.1).

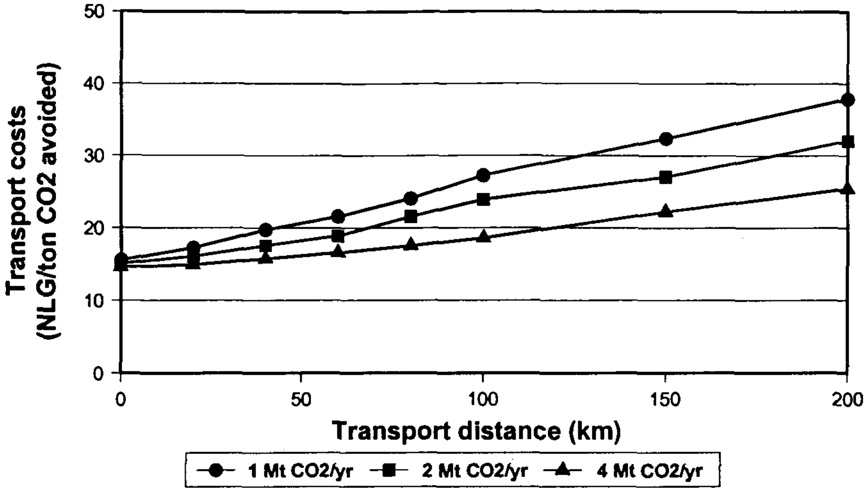

Figure 4.1 Correlation between transport costs and distance assuming industrial sources with capture rates of 1, 2, and 4 million tones CO2 (Wildenborg 2000, 3, by permission)[3]

Due to the common occurrence of saline aquifers in sedimentary basins that also contain hydrocarbons, as is the case in both Alberta and Saskatchewan Basins, the distance to a disposal site from a capture site may be kept to an affordable range (Fisher, Sloan, and Mortensen 2002). For this study it is assumed that the total pipeline required to transport CO_2 from a capture facility to a storage site would average thirty kilometres per capture facility.

Storage costs are often linked to the capture process used and, in particular, to the CO_2 output from a capture plant. When the rate of CO_2 capture exceeds the CO_2 aquifer injection rate, more injection sites would be needed and costs rise (Stork 1999) (Figure 4.2). However, economies of scale are possible with storing CO_2 (increased amounts of CO_2 result in decreased per unit cost of storing CO_2), due to decreased equipment costs per unit of CO_2 stored.

---

[3] NLG stands for The Netherland's Guilder 2.3 NLG=1 USD

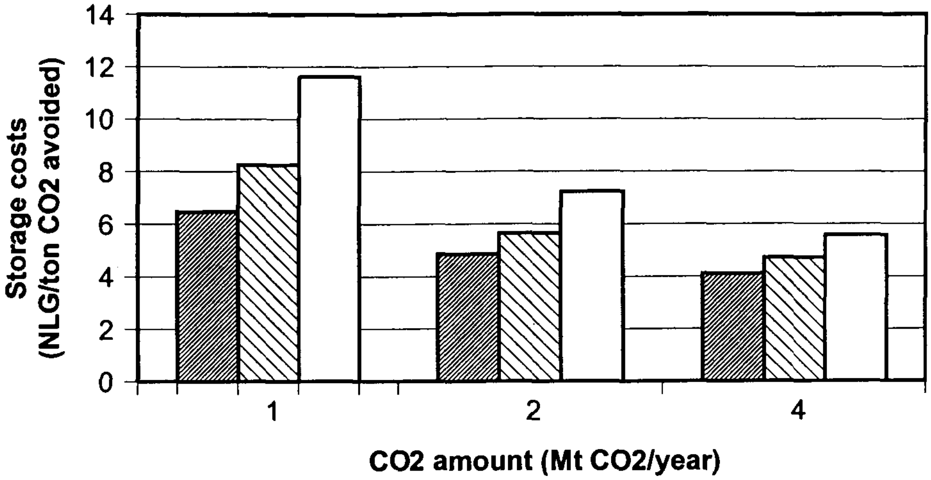

Figure 4.2 Increases in storage costs for injecting into multiple, proximate aquifers (narrow stripes=2 wells, wide stripes=4 wells, white= 8 wells) (Wildenborg 2000, 3, by permission)

The cost of developing a site is also affected by the storage depth due to the high cost of drilling. Drilling cost is influenced by uncertainties associated with the storage capacity and pressure regime of an aquifer, which can only be determined from detailed geological surveys (Stork 1999). The pressure regime of an aquifer is particularly important as it determines the rate at which CO_2 can be added to an aquifer, which may or may not be the same rate at which CO_2 is captured.

Costs are significantly reduced for CO_2 disposal (transport and storage) from NGCC facilities relative to coal facilities, due to a significant reduction in the amount of CO_2 produced by NGCC facilities (Table 4.3). For storage of CO_2 captured from a 500 MW coal-fired power plant, it is assumed that the initial injection rate of 2000 tonnes CO_2 per day would fall to 1600 tonnes per day over 30 years, requiring 6 injection wells (Stork 2001). Storage costs for CO_2 captured from NGCC and IGCC facilities are assumed to be 40% (NGCC) and 84% (IGCC) of the amount from a coal facility. While the number of wells, the amount of land needed, and field costs, all decrease (Williams

2001), the same amount of pipeline is still required to reach a storage site and this pipeline must also be maintained.

Table 4.2 Costs for the transport and storage of CO2 from various flue gas sources.

Power Facility	Coal	NGCC	IGCC
Capital Costs ($/KW)			
Pipeline (30km length)	20.00	20.00	20.00
Well System	13.42	3.55	12.21
Field Costs	3.15	1.05	3.13
Project Development and Land Acquisition	21.47	4.25	21.47
Total Transport and Storage Costs ($/KW)	58.42	27.85	56.71

4.2 Geological Uncertainty Scenario

While it is possible to sequester or store CO_2 in several different media, this study focuses on the option of storing CO_2 in saline aquifers. Saline aquifers are porous rock layers into or out of which water, as well as other molecules, can be pumped (Bachu 2000). They provide the second largest capacity for CO_2 storage after ocean disposal. Canada has a large number of potentially suitable saline aquifers for CO_2 storage, many of which are in close proximity to large CO_2 emitting power plants. In addition, the technology for transporting and pumping CO_2 underground has already been developed and implemented at the Weyburn Enhanced Oil Recovery Project in Saskatchewan. However, the level of knowledge regarding the geological feasibility of storing CO_2 in Canada's saline aquifers is low due to the small number of saline-aquifer exploratory wells and the limited seismic data available (Fisher, Sloan, and Mortensen 2002). To gain a better understanding of the geological feasibility and risks involved in storing CO_2 in saline aquifers, it is important to understand both the impacts of a CO_2 leak occurring, as well as the geological attributes of saline aquifers that affect the probability of a leak.

4.2.1 Impacts from a CO_2 leak

CO_2, at high enough concentrations can cause serious health impacts. At a concentration of 5% of total air volume, increased respiration rates, headaches, breathing difficulty, weakness, and dizziness may occur (Holloway 1997). Concentrations exceeding 10% result in instantaneous unconsciousness and may be followed by death; at 20% concentration instantaneous fatality occurs (Kruse and Tekeila 1996). While the impacts associated with pipeline transport of CO_2 are fairly well understood from the enhanced oil and gas industries (Kruse and Tekeila 1996), the impacts resulting from leaks of CO_2 from saline aquifers are not fully understood. The closest information available is from large CO_2 releases that have occurred due to seismic activity, including examples from Dieng, Indonesia; Mammoth Mountain, California; and Lake Nyos in Cameroon.

In Dieng, the eruption of the Dieng Volcano resulted in the release of CO_2, which flowed as a dense gas down from the volcano onto a nearby plain, displacing oxygen from the local environment, destroying surrounding vegetation, and killing 500 local inhabitants (Allard, Djlevic, and Delarue 1989). Similar results were observed in 1986 when the 220 m Lake Nyos, Cameroon, overturned. CO_2 that had built up in the bottom of the lake was released in the local atmosphere resulting in the death of over 1700 local residents, due to asphyxiation (Sigvaldason 1989).

The continual release of CO_2 from magma deep within the volcanic cone of Mammoth Mountain, California has destroyed large tracts of trees on the mountain. While the released concentrations of CO_2 are not enough to harm human health, CO_2

concentrations have exceeded 10% of total air volume at several enclosed locations (Farrar et al. 1995).

While all of these examples occur in areas that are seismically active, and would not be considered as candidates for CO_2 storage, they demonstrate the hazards a large CO_2 release could impose on both human and ecological health.

4.2.2 Probability of a CO_2 Leak

The probability or likelihood of a leak occurring from a CO_2 storage project is linked to both the geological attributes of an aquifer as well as the possibility of human error involved in pumping the CO_2 into an aquifer. There are two possible types of CO_2 leaks that could occur: a large leak resulting from an earthquake, volcano, or fault; and a gradual leak over time resulting from CO_2 escaping at an aquifer's release point due to over-pressurization, small faults or cracks, or geochemical complications.

The probability of having a large leak from seismic activity, such as an earthquake, may be minimized through careful aquifer site selection. Saline aquifers are found in most sedimentary basins with the level of seismic activity being a function of the location and type of basin. The two basins currently being considered for CO_2 storage—the Williston and Alberta Basins—are both located on seismically stable continental crusts. However, this is not the case for all aquifer-containing basins (Kingston, Oishroon, and Williams 1983). Selecting an appropriate aquifer for CO_2 storage should take into account the amount of seismic activity within the sedimentary basin in which an aquifer is located.

Leaks resulting from a blown well, from an unknown release point (a previously drilled well), small faults, cracks, or geothermal complications are a function of the geological properties of an aquifer and our lack of understanding in regards to these properties. Determining the total capacity for storage, the flow patterns, and how the addition of CO_2 would influence these flow patterns are important to ensure leaks are avoided.

4.2.3 Total Aquifer Storage Capacity

The amount of CO_2 that can be stored within a confined saline aquifer is a function of the specific storage and the specific yield of an aquifer (equation one). Specific storage is the volume of fluid that a volumetric unit of an aquifer absorbs or expels with a unit change in pressure (equation two). CO_2 is usually compressed to a fluid state before being injected into the aquifer.

$$\mathbf{V = (Sy + bSs)\ (A)\ (\Delta h)} \tag{1}$$

V – volume
Sy – Specific Yield
b – aquifer thickness
A – surface area of aquifer
Δh – change in height due to elasticity
Ss – specific storage

$$\mathbf{Ss = \rho_w g\ (\alpha + n\beta)} \tag{2}$$

Ss – specific storage
ρ_w – density of the fluid
g – gravity
α - aquifer compressibility
n - porosity
β - fluid compressibility

The specific yield of an aquifer is reached when drainage forces, due to the force of gravity, equal the attractive forces—or water tension—that cause water molecules to cling to each other and to surfaces (Fetter 2001). Both specific storage and specific yield are influenced by porosity, density, depth, hydraulic head, and compressibility of both an aquifer and its fluids (Fetter 2001).

The storage capacity of an aquifer is primarily dependent on its pore space, which is a critical element in selecting a storage site (Bachu 2001). Aquifers are generally found in sedimentary basins. As individual sand grains that comprise an aquifer are deposited, openings between grains--or pore spaces--are formed. This is referred to as primary porosity (Fetter 2001). Because these sand grains, or a variety of other size sediments, can be of different size and composition and can be deposited through different processes, not all sedimentary layers have the same level of porosity (Holloway 1997). Further heterogeneity in sedimentary porosity is possible due to fractures; this is referred to as secondary porosity (Fetter 2001). It is within the available spaces created by pores and fractures that water, as well as CO_2, can be stored.

Also affecting storage of both water and CO_2 within an aquifer is the density of material stored. The lower the density of the injected CO_2, the easier it is for CO_2 to move through an aquifer and the less likely it is that the CO_2 will become permanently trapped within an aquifer. In order to slow the movement of CO_2 within an aquifer, and increase its residence time, CO_2 should be injected into a aquifer in a supercritical state (Figure 3.1), which gives it the density of a liquid but the expansive properties of a gas (Fisher, Sloan, and Mortensen 2002).

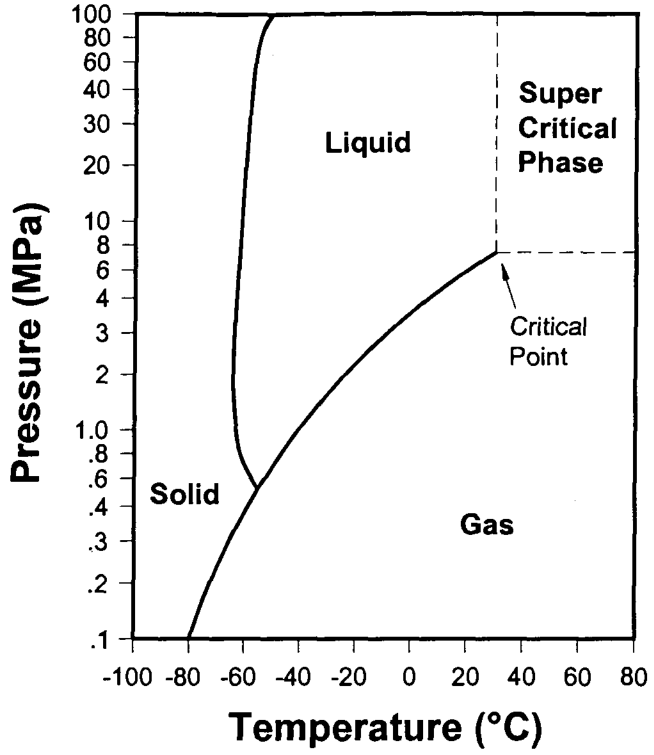

Figure 4.3 Influence of temperature and pressure gradients on the state of CO2 (Bachu 2000, 955, by permission)

It is generally believed that by injecting supercritical CO_2 into an aquifer at a depth of greater than 800m, CO_2 will remain in this super-critical state (Hitchon et al. 1999; Hoolway 1997; Hitchon et al. 1999; Lindeberg 1997). However, this simplification does not take into account the density regime of specific aquifers, which can vary greatly depending on local temperature and hydrostatic pressure gradients (Figure 4.4). Geothermal gradients within an aquifer can range from 0.02 to 0.06 °C/m, depending on such conditions as basin type, tectonic activity, proximity to other heat sources, surface temperature, and density of both the formation and aquifer water (Bachu 2000). Hydrostatic pressure gradients (bar/m) are affected by regional rock composition, surface erosion, and local hydrocarbon production (Fetter 2001). In response to these regional characteristics, hydrostatic pressure gradients may vary between 0.0105 and 0.0124 Mega

Pascals per meter (MPa/m), sometimes reaching 0.023 MPa/m (Hendriks and Blok 1993). Density of CO_2 and fluids within a saline aquifer will depend on a reservoir depth as well as local geothermal and pressure gradients.

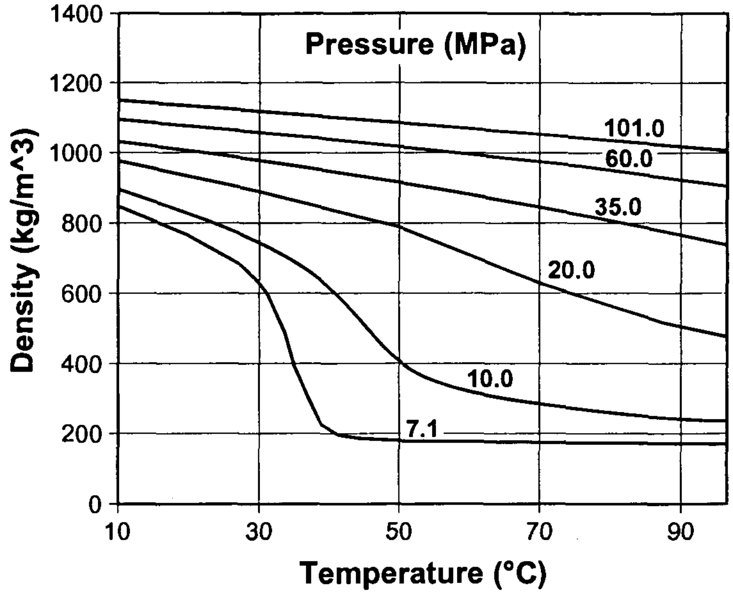

Figure 4.4 Density-Temperature Profile of the Liquid and Supercritical phases of CO2. (Bachu 2000, 955, by permission)

Changes in hydraulic head affect the arrangement of mineral grains and the density of water in the pore space within an aquifer, thus affecting its total storage (Fetter 2001). Hydraulic head, or the total mechanical energy per unit weight of water, is the sum of all the forces acting upon an aquifer (equation three, Fetter 2001). As the hydraulic head increases, increasing the pressure within an aquifer, aquifer volume will increase. As an aquifer compresses, following a decline in hydraulic head or pressure, a reduction in porosity occurs and water is expelled from the aquifer. Water is also compressed during such a pressure drop resulting in further water expulsion from the aquifer.

$h = z + (P/\rho g) + (v^2/2g)$ (3) (Fetter 2001)

- where:

  h – hydraulic head

  ρ - density

  z – depth

  g – gravity

  P – pressure

  v - velocity

Hydraulic head, as a function of all forces acting upon an aquifer, is made up of three components: elevation head, pressure head, and velocity head at a give point. While elevation head is the force of gravity relative to the depth of an aquifer--or the position of the fluid mass with respect to sea level--pressure head is a measure of the pressure of the surrounding fluid for a fluid of a given density (Fetter, 2001). Pressure head may be affected by surface erosion which releases pressure, the production of hydrocarbons which increases pressure, as well as other geological processes such as plate movement and volcanoes (ibid). The final component of hydraulic head, velocity head, is proportional to the mass of a fluid and the speed with which a fluid is moving. This component is often ignored due to the slow speed at which fluids travel within an aquifer.

All of these characteristics that influence the specific storage capacity of an aquifer vary depending on regional conditions (ibid). Extremely large aquifers, such as those in the Alberta and Williston Basins, can cover thousands of square kilometres. Temperature and pressure can vary significantly throughout an aquifer affecting both fluid density and the hydraulic head. Characteristics such as porosity and specific yield can also vary significantly on a regional level in response to variations in chemical composition of the surrounding aquifer sediments (Law and Bachu 1995). To account for this variability, models may be built that divide an aquifer into more homogeneous sections based on the aquifer hydrogeology

4.2.4 Fluid Flow within Saline Aquifers

Closely related to aquifer storage capacity is the movement, or flow, of fluids within an aquifer. While the movement of fluids within an aquifer is very slow, on the order of 0.1 meters per year (Bachu, Gunter, and Perkins 1994), it is important to understand the natural pathways of fluids and how these pathways are altered by the addition of CO_2. By investigating these characteristics scientists will gain a better understanding of how long CO_2 will remain stored within an aquifer. Hydrogeological characteristics that affect the flow of fluids as well as CO_2 within an aquifer include: aquifer permeability, density of both the fluids and CO_2, the topography of an aquifer, and changes in hydraulic head of the aquifer (Lindeberg and Wessel-Berg 1997).

The flow rate depends primarily on the permeability of an aquifer (Bachu 2001). Permeability is defined as the volume of void spaces or pores through which water or other fluids can travel in a rock or aquifer, divided by the total volume of the rock or aquifer (Fetter 2001). Unlike porosity, permeability is a function of the connections—or linkages—between pores. However, like porosity, permeability is affected by both sediment grain size, and variability in grain size. The combination of increased median grain size and decreased variability in grain size, results in wider spaces between pores, increasing the flow path of a fluid. An aquifer which is well suited for CO_2 storage would be highly permeable at an injection well site and have low permeability further from a well site. This is desirable, so as to achieve high rates of injection and also ensure that the injected fluid remains trapped within an aquifer (Bachu 2001).

The density of fluids within an aquifer also affects fluid flow. The lower the density, the easier it is for a fluid to move through permeable rock layers (Fetter 2001). Conversely, increases in density of aquifer waters results in increased viscosity leading to a decrease in velocity within an aquifer.

Hydraulic head, or the total mechanical energy per unit weight of water, can also influence flow pathways within an aquifer (Fetter, 2001). Fluids generally travel from areas of high pressure to areas of low pressure. If the hydraulic head is higher at an injection well site due to increased fluid pressure, or if an injection site is at a greater depth than other parts of an aquifer, the aquifer fluids will move towards the area of lower pressure, or lower depth, in response to pressure differences.

There is a link between the flow of the formation waters and the topography of a sedimentary basin, because both elevation head and pressure head are influenced by local topography. In basins located on a marine shelf such as the Scotian Shelf, flow is driven by compaction; fluids travel vertically out of shales and laterally outward toward the basin margin (Bachu 2000). As a result of compacting forces, aquifers in these basins are usually over-pressurized, possibly resulting in fracturing problems if CO_2 were injected. Continental structures, such as the Alberta and Williston Basins, are normally undergoing significant uplifting and erosion. Because of this uplifting process, fluids are driven vertically into thick shales and laterally inward in thin adjacent aquifers (Figure 4.5) (Bachu 2000). These types of flow systems are driven by topography, with fluids moving from recharge areas at high elevations to discharge areas at low elevations. Aquifer pressures are usually low, and velocity of movement controlled by the permeability distribution within a basin—is extremely low, leading to long residence times within continental basins (Bachu 2000). It is these flow characteristics that make aquifers within this type of basin the best suited for CO_2 storage.

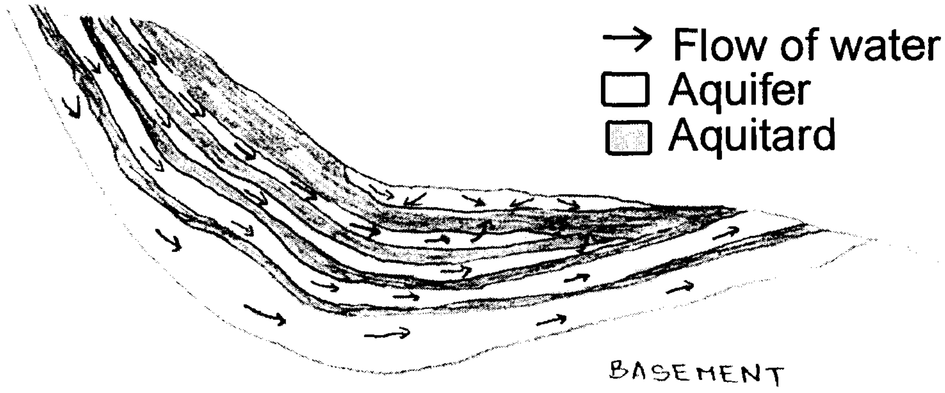

Figure 4.5 Flow system for a typical continental basin, where fluid flow is topography driven (modified from Bachu 2000)

4.2.5 CO_2 Movement within Saline Aquifers

The addition of CO_2 to a saline aquifer will impact both its flow patterns and physical properties. While molecular diffusion and migration will contribute to fluid as well as solute (such as CO_2) transport, characteristics such as viscosity, friction, salinity, and mineral interactions work together to slow solute transport (Lindeberg 1997). It is the interactions of these various forces that determine how long CO_2 will remain stored within an aquifer.

The movement of CO_2 within an aquifer is dependent on density differences between aquifer fluids and CO_2 (Law and Bachu 1995); the greater the density and viscosity differences between CO_2 and the formation fluid, the lower the amount of CO_2 that will dissolve into formation waters. If CO_2 is injected into an aquifer in a less-dense gaseous form, vertical convection of less-dense CO_2 results in decreased diffusion and increased concentrations of CO_2 at the uppermost reaches of the permeable region (Lindeberg and Wessel-Berg 1997). However, if CO_2 is injected in a supercritical state, the density of CO_2 is close to that of water, resulting in greater solubility during, and following, this convection process. As CO_2 diffuses into formation water, the density gradient within an aquifer will change. Denser water will move deeper into an aquifer while less dense water takes its place, increasing CO_2 diffusion and an aquifer's storage capacity (Lindeberg and Wessel-Berg 1997).

This type of hydrodynamic trapping is possible in many large aquifers confined by a horizontal non-permeable cap rock (Bachu 2000). In the past, such aquifers were thought to be inappropriate for CO_2 storage due to the lack of physical traps. However, trapping can occur through other processes.

Hydrodynamic trapping occurs when CO_2 is injected and dissolves in formation waters that are flowing inward towards the center of the basin. As the formation water flows inward, CO_2 is sequestered permanently because the flow direction is into adjacent non-permeable shales (Law and Bachu 1995).

In addition to the hydrodynamic trapping of CO_2 within saline aquifers, CO_2 can also be trapped through the binding of CO_2 in chemical compounds (Hitchon et al. 1999).

This process, termed mineral trapping, occurs when CO_2 dissolves in water and interacts with water molecules forming a bicarbonate and hydrogen ion. These free hydrogen ions create acidic conditions in the formation water resulting in the breakdown of silicate materials present in an aquifer rock formation (Hitchon et al. 1999). This release of free ions—such as calcium, magnesium, and iron that bind to the bicarbonate ion—produces calcite, dolomite, siderite, and quartz. This permanently fixes the CO_2 as a mineral (ibid). Because this trapping process is most likely to occur in aquifers that contain minerals such as feldspars and clay, sandstone-based aquifers are favoured over carbonate aquifers for CO_2 storage. However, mineral trapping can take tens to hundreds of years to occur requiring the CO_2 to be hydro-dynamically trapped in an aquifer for long periods.

Storage capacity of any underground disposal project must, therefore, be related not only to the quantity of CO_2 that can be stored, but also to residence time for injected CO_2. Aquifers considered for future CO_2 storage need to be evaluated not only on storage capacity, but also on escape rates and residence time. These variables should be compared to a projected lifetime for the fossil fuel era (time period in which we will continue to use CO_2) and the rates at which CO_2 could be taken up by the ocean and biosphere at the proposed release date.

Because of the potential human and vegetative health impacts that could result from a large, sudden CO_2 leak, it is important to ensure that a rigorous site selection process is established and conducted prior to selecting a long-term storage site for CO_2. Such a process needs to consider the level of seismic activity in a region, the storage capacity of an aquifer, and the residence time or flow patters of the formation fluids within an aquifer. While uncertainty surrounds both the geological feasibility of the use of saline aquifers for CO_2 storage, scientific research currently underway may lead to reduced costs, a greater understanding of the geological attributes of saline aquifers, and how these attributes change with the addition of CO_2. However, there is still a lack of understanding regarding the ecological impacts of sudden CO_2 leaks, both large and small. Information in this area is necessary in order to ensure human acceptance of a saline-aquifer disposal project.

4.2.6 Societal Response to Geological Uncertainties

The costs and economic parameters derived from engineering analyses, and used in the base case scenario (Section 4.1), are based on the economic assumptions of energy and financial markets. These, however, may overlook key environmental and social considerations. In the case of CO_2 capture and storage, geological uncertainties and risks involved with storing CO_2 in aquifers may result in increased societal concern which could lead to increases in insurance rates and more stringent government regulations.

Government regulations, or standards, often developed in response to societal concern, may increase the cost of CO_2 capture and storage. One process that is already in place, and which influences the construction of any project with a significant environmental impact, is the *Canadian Environmental Assessment Act*. The cost for a project in this process varies depending on the type of project and the level of risk. Generally, costs for this assessment process range from 7.6% to 13.4% of capital costs (Halger and Bailly 1999), but these costs may increase due to the length of an assessment process. Also, first-time projects, or projects that generate a large amount of public concern, tend to take longer due to the absence of developed protocols and increased public consultation periods.

The longer the environmental review process, the longer the construction period and the larger the construction costs (Halger and Bailly 1999). Because of the high upfront capital costs, equivalent to those for nuclear power, accumulated interest can dramatically affect the cost of a capture facility. In the case of the nuclear industry, costs sometimes increased three fold from those initially predicted due to the length of the construction period (Shakow and Goble 1982).

Investors and companies interested in implementing new technologies may also have concerns regarding the risks associated with CO_2 capture and storage technologies. New technologies have a higher chance of premature failure than conventional technologies. Their higher up-front costs, in combination with long payback periods, further increase the cumulative probability of an accident, or failure, or possible onset of undesirable economic conditions prior to a return on initial investment (Shakow and Goble 1982). All of these uncertainties, and the added difficulty of predicting future consumer preferences, make new technologies less attractive to investors (Jaccard, Nyboer, and Sadownik 2002).

Despite these uncertainties, government and industry are both interested in capture and storage technologies because they do not require a significant change in consumer lifestyles or the fossil-fuel-based economy. However, CO_2 capture and storage technologies are not now in existence at a level for which future costs can accurately be predicted. Estimates discussed in the base case, and currently being analyzed by other energy-economy models, are based on engineering analyses that often overlook external social and environmental costs. It is often these concepts that are most important in determining the pace of a technology's advancement.

Geological uncertainties, related to storage of CO_2 in saline aquifers, can potentially lead to increased costs for these technologies through an increased need for monitoring, careful site selection, and increased exploration. Minimization of geological uncertainties may be achieved through an increased understanding and quantification of the geological properties that affect the movement of CO_2 within an aquifer (Holloway 1997). However, such quantification requires a large amount of data as well as scientific knowledge to interpret the collected data. While the necessary geological information may be available in areas that were previously used for hydrocarbon extraction (Bachu 2001), understanding how addition of CO_2 would affect these properties is currently not well understood, although research in this field is accelerating rapidly. Collecting scientific information to reduce the probability of a leak occurring requires an extensive geological research program, which could increase exploration and siting expenses (Wildenborg 2000). The cost for a preliminary site screening, for example, is estimated to be $300,000 (CDN) with each site evaluation costing $1.3 million (CDN), including: drilling ten-groundwater-sampling wells at a site, analysing groundwater samples, drilling a test well for a saline aquifer, and site modelling (Wildenborg 2000). Through more rigorous examination of potential sites, it is likely that the proportion of sites chosen out of those examined would decrease. It is also probable that the number of exploratory well sites would also rise (Figure 4.6), increasing the cost for storing CO_2. However, economies of scale also exist in exploration storage costs; the greater the amount of CO_2 stored in a year, the less of an impact exploration success has on per unit storage cost of CO_2.

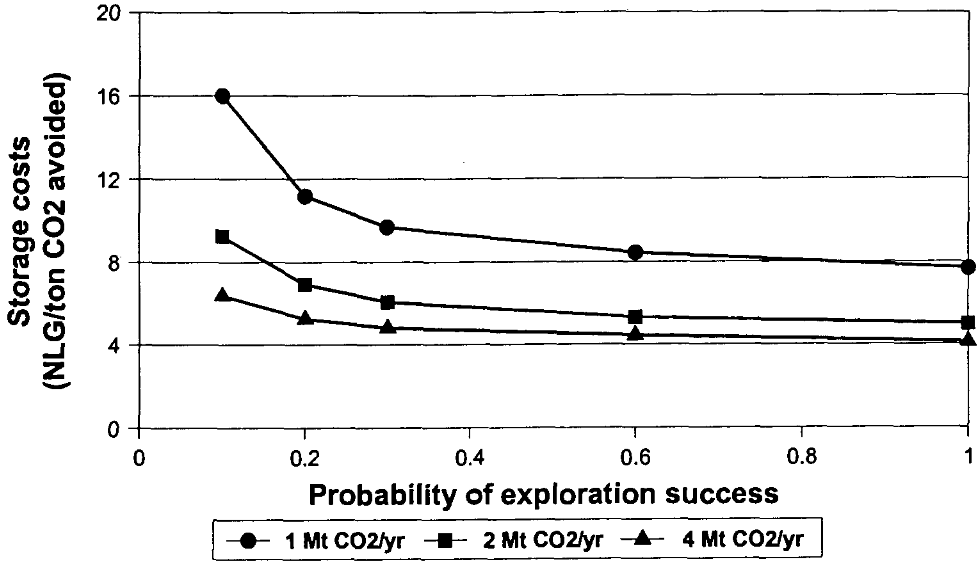

Figure 4.6 Storage costs and the success rate of exploration for aquifer traps (Wildenborg 2000, 4, by permission)

Geological data can be analyzed to determine where injected CO_2 would be likely to move and how quickly it might reach the surface. However, confidence in such predictions is only possible through testing or monitoring the flow patterns of CO_2 within an aquifer. This is particularly important in areas of previous hydrocarbon activity where unknown, abandoned, or poorly-filled wells might influence the migration of CO_2 to the surface (Bachu 2001). Monitoring cost , estimated at $1.5 million (CDN) to drill two additional saline aquifer monitoring wells and ten additional surface water wells (Wildenborg 2000), are not mentioned in most studies in the literature and need to be included for a more accurate cost estimate.

Geological uncertainty and the risks involved with storing CO_2 in saline aquifers may also result in increased societal concern leading to increases in insurance rates and more stringent government regulations. While insurance rates have been estimated at somewhere between 0.5% and 3% of capital costs in some studies (Doctor et al. 2001; Wildenborg 2000), other studies do not included insurance in their calculation of operation, maintenance,, or capital costs (David 2000). Government regulations, developed in response to societal concerns, may also increase the cost of CO_2 storage. One process already in place, that influences the construction of any environmentally significant project, is the Canadian Environmental Assessment Process. The cost of completing an environmental assessment is significant and can be further magnified by a lengthy assessment process, common for new projects or projects that generate a large amount of public concern.

Another group of costs missing from the baseline cost estimate are long-term economic costs. These include the expense incurred for waste management, decommissioning, and eventual shutdown of a plant. As a plant ages, degradation of capacity factors also occurs leading to an increase in operating and maintenance costs and a decrease in the predictability of unit availability. When a plant is shut down demolition costs, sometime as high as 10% of the total project cost, are also incurred (Bachu 2000).

Finally, all three CO_2 capture, power generation facilities use a significantly greater amount of water for additional cooling processes relative to the original non-capture generating facility (Doctor et al. 2001). The cost of water is often considered to be insignificant relative to other costs; however, the environmental impact of increased water usage may play a role in increasing the costs of CO_2 capture and storage, particularly in Alberta and Saskatchewan, where their agriculture industries were significantly impacted by drought in 2002 and 2003.

Using the base case scenario as a starting point, a second scenario was developed that takes into account the above-mentioned considerations in capital and operating costs. To do so, costs in the baseline scenario were adjusted in the following manner:

- Capital costs for constructing a capture facility are increased by 10% to reflect the requirement of a full environmental assessment under CEAA. The 10% value is used as it is the average calculated by Hager and Bailly (1999) for all projects proceeding through an environmental assessment process.
- Operating costs are increased by 100% to reflect an increased need for waste management, insurance, increased storage-site monitoring, pipeline monitoring, and water.
- Transport and storage costs are also increased by 100% to reflect increased exploration (probability of finding an appropriate aquifer decreases causing increased exploration and thus increased costs), more monitoring wells, longer pipelines to reach appropriate sites, as well as increased drilling.

These increased costs for CO_2 capture and storage are summarized in Table 4.3. CO_2 output and relative power output are assumed to remain the same. While operating, transport, and storage costs have all increased significantly this does not have a large impact on the cost of CO_2 capture and storage as the capital cost of the capture stage is much more expense than any of the other costs.

Table 4.3 CO_2 capture and storage costs for the geological uncertainty scenario. [a]

Capture Process	Coal–MEA	NGCC–MEA	IGCC– syngas
Capture Costs ($/kW)	2988	1447	2731
Carbon Output (kg/kWh)	0.105	0.042	0.088
Relative Power Output	31%	48%	36.1%
Transport and Storage Costs ($/kW)	245.36	116.95	238.16
Total Capital Costs ($/kW)	3233	1564	2969
Operational Costs ($/kW per year)	536	174	396

[a] Costs are all in Canadian Dollars

4.3 Declining Cost Scenario

There are additional economic parameters that need to be considered when examining a technology to determine its potential future cost: economies of scale, learning curves, and technological progress. This section describes these parameters and how they apply to CO_2 capture and storage technologies, as well as outlines a third future scenario that incorporates these parameters.

4.3.1 Economies of Scale

Economies of scale occur when an expansion in output of a plant permits a reduction of costs per unit output. This may occur through the increased specialization of tasks including mechanization or through non-scaling inputs that do not increased as output increases, such as research and development costs. Economies of scale may also come into effect when productive capacity increases by proportionately more than the increase in the costs of the required construction materials (Lipsey, Purvis, and Steiner 1991). However, there is some point at which an expansion of output no longer results in a reduction of costs per unit of output and instead results in an increase. Diseconomies of scale may result from difficulties in managing and controlling an enterprise as its size increases, alienation of the labour force, and difficulties in providing supervision or maintaining good communication in a multi-tiered organization (Lipsey, Purvis, and

Steiner 1991). Some researchers believe that the cost of capture and storage would be less per unit of CO_2 captured if this process took place at large centralized electricity or hydrogen generation plants rather than from several smaller electricity generating facilities (Williams 2001).

4.3.2 Learning Curve

While economies of scale focus on variations due to level of output, costs can also vary with the length of time a product has been produced. The learning curve is one such phenomenon, which may be present whenever a new—or previously untried process—is introduced (Lipsey, Purvis, and Steiner 1991). This curve indicates how a firm's cost of producing a given output falls as the total amount produced increases over time, due to accumulated learning (Delionback 1995). The theory behind the learning curve is that successive identical operations will take less time, use fewer resources, or cost less than preceding operations (Stewart 1995). Because economies of scale and economies of learning are difficult to separate, they are often lumped together in a single estimate of declining costs with increased output of a new technology (McDonald and Schrattenholzer 2001).

When developing a declining-cost estimate for technologies that are not yet available on a large scale, economists often use data from similar technologies. A declining capital-cost function for CO_2 capture and storage technologies can be developed using data from other energy-producing technologies. Past studies of such technologies indicate that for each doubling of cumulative production, specific production costs decrease by 17% (Claeson 1999; Fisher 1974; IEA 2000; Joskow and Rose 1985; MacDonald and Schrattenholzer 2001).

However, extrapolation using historical data from different technologies presumes that the conditions that created the experience curve for a different technology will be the same for an emerging technology. Application of an average-based learning curve must avoid overly optimistic (high percentage) declining cost functions, especially when applying such functions to technologies that have only a few units in operation (Stewart 1995).

4.3.3 Technological Progress

Several new technologies are being developed which increase the energy efficiency of the CO_2 capture process, thus decreasing both energy requirements and the cost of CO_2 capture and storage. Two potential cost-reducing design options are available. These include: 1) the development of a new chemical absorption process to replace monoethanolamine (MEA) in the separation of CO_2 from flue gases, and 2) the development of an oxygen-production membrane to replace the cryogenic oxygen production process currently used to separate oxygen from air for use in the IGCC process.

The newly developed CO_2 chemical separation solvent, Kansai Solvent (KS-1)—named after the company that developed it—has several advantages over the traditionally used MEA solvent. These advantages include a lower circulation rate due to a higher affinity for CO_2 molecules; a lower regeneration temperature (110°C) resulting in decreased energy costs; noncorrosive properties; and a 10-15% lower heat of reaction with CO_2, which also reduces energy requirements. KS-1 is already in use at a fertilizer plant in Malaysia where its 12% lower energy requirement for regeneration has resulted in a drop in steam demand from 20% to 7.3% of the total usable steam-created energy (Chapel, Ernest, and Mariz 2001).

The newly-developed ALSTOM Power oxygen membrane provides a cheaper alternative to the cryogenic oxygen—separation unit currently used by IGCC facilities. These membranes incorporate oxygen ions into ion vacancies within their crystalline structure and transport these ions through the membrane by sequentially occupying oxygen-ion vacancies. This process, driven by both pressure and high temperatures, results in a 2% efficiency loss from traditional power-plant efficiency as opposed to the 10% efficiency observed in the flue-gas separation process (Marion et al. 2001).

In developing a series of divergent scenarios that provide a larger range of future possibilities, it is important to examine factors that could both decrease as well as increase costs. Starting with the average costs and performance parameters of the base case scenario, a low-cost scenario is created. The following list describes the changes made to the base-case scenario.

- Capital costs for constructing a CO_2 capture facility are decreased by 17%, the declining cost function for energy-producing technologies. This 17% reduction is made because many studies used in the base case are from the early 1990's and several newer and larger CO_2 capture facilities have been built since that time, allowing for increased learning. This cost decrease is supported by studies from EPRI (2000) and Wheeler (2000) that predict similar results.
- Operating costs for all stages are also decreased by 17% for the same reasons as those above.
- Capital costs for transport and storage are reduced by 17% to reflect the experience that has been gained from the Weyburn, Saskatchewan Enhanced-Oil-Recovery Operation and the North Sea, Statoil "Sleipner T" Urtisa Formation (offshore saline aquifer) projects, which have been underway for the past four years.
- Relative power output is increased by 8% to reflect the new technological developments that have occurred in this field. In addition to the Kansai Solvent and Alstom Oxygen membranes mentioned above, other new developments which promise further increases are also being investigated.
- CO_2 emissions remain the same.

The lowered costs (capital and operating) and increased relative output of the low cost scenario are listed in Table 4.4. NGCC-MEA has the lowest capital and operating costs and the highest relative power output, making it the most financially attractive option. IGCC-syngas, however, is only slightly less expensive when compared to coal-MEA process.

Table 4.4 CO_2 capture and storage costs for the economic certainty scenario.

Capture Process	Coal–MEA	NGCC–MEA	IGCC–syngas
Capital Cost - Capture ($/kW)	2774	1260	2444
Carbon Output (kg/kWh)	0.105	0.042	0.088
Relative Power Output	39%	55%	44%
Transport and Storage Costs ($/KW)	48.49	23.11	47.07
Total Capital Costs ($/KW)	2822	1284	2491
Operational Costs ($/kW per year)	223	72	164

[a] Costs are all in Canadian Dollars

4.4 Summary of the Three Scenarios

The cost and performance parameters for each of the three scenarios and the technologies included vary significantly (Table 4.5). The discount rate, variance parameter, and intangible costs are assumed to be the same as the base technology to which CO_2 capture and storage has been applied (see discussion in Section 3.2.3).

Table 4.5 The performance parameters used in the CIMS model for each of the three scenarios.

Scenario	Technology	Coal-MEA	NGCC-MEA	IGCC-syngas
Base Case	Capital Costs ($/kW)	3342	1519	2945
	Operating Costs ($/kW)	268	87	198
	Power Output	31%	48%	36%
Higher Costs (due to Geological Uncertainty)	Capital Costs ($/kW)	3619	1698	3318
	Operating Costs ($/kW)	536	174	396
	Power Output	31%	48%	36%
Lower Costs (due to Economic Efficiencies)	Capital Costs ($/kW)	2774	1260	2444
	Operating Costs ($/kW)	223	72	164
	Power Output	39%	55%	44%

The two types of capture and storage technologies that are available as retrofits for single-cycle coal facilities and the capital costs of these technologies vary depending on the scenario assumptions (Table 4.6). Capital costs for retrofitting differ among scenarios based on the same assumptions discussed for the entire technology or greenfield plant. Retrofitting with IGCC-syngas is cheaper than retrofitting with MEA.

Table 4.6 Capital costs for retrofitting with CO_2 capture and storage technologies

Scenario	Coal-MEA	IGCC-syngas
Base Case	965,250,000	787,410,000
Higher Costs	1,138,995,000	929,143,800
Lower Costs	825,082,675	672,808,344

Each of these three scenarios is incorporated into the CIMS model with four different GHG-emissions-reduction policies applied to each scenario, a $10, $50, $150, and $250 tax per tonne of CO_2. Data are analyzed for two time-periods, 2010 and 2030.

5.0 Results

Much of Canada's electricity (74%) is produced from sources with negligible CO_2 emissions (hydro, nuclear, and renewables), yet combustion of fossil fuels for electricity production accounts for 18% of Canada's total emissions (Jaccard, Nyboer, and Sadownik 2002). Previous economic analyses indicate that replacing fossil-fuel-burning power facilities, particularly in Alberta and Saskatchewan, generates a significant reduction in GHG's. Many of these large emitters were constructed in the 1970's and have significant life remaining, which constrains the sector's current ability to adopt newer and cleaner technologies (Jaccard, Nyboer, and Sadownik 2002). However, it is possible to retrofit these facilities to capture CO_2, allowing them to continue operating while reducing their GHG's. Given the large volume of emissions released by these power facilities, and the relative ease in retrofitting them, it is possible that CO_2 capture and storage technologies will play an important role in reducing GHG's but several uncertainties remain. This research project determines that these uncertainties, which are characterized in three different cost scenarios (low, medium, and high cost), influence Canada's ability to meet its Kyoto Target when analyzed using CIMS.

5.1 Life-cycle Costs

In each CIMS simulation, electricity-supply technologies compete based on their life-cycle costs, calculated by CIMS using a variety of attributes. These include: capital costs, operating costs, intangible costs, and discount rates. For a full discussion of all attributes see Section 3.2.3; values for each scenario are listed in Section 4.4.

5.1.1 Life-cycle Costs for CO_2 Capture and Storage Technologies

These expenses vary depending on the scenario and tax rate applied (Table 5.1). The low-cost scenario has the lowest life-cycle cost while the high-cost scenario has the highest life-cycle cost. Life-cycle costs also increase as tax rates increase. This is due to CO_2 emissions from these technologies, although being much less than their parent technology, still having a CO_2 tax applied to them, increasing their life-cycle cost.

Table 5.1 Life-cycle costs ($/GJ) for CO_2 Capture and Storage Technologies

Technology	Cost	CIMS Scenario		
	Scenario	no tax	$50 tax	$150 tax
NGCC	Low	$29.59	$30.04	$30.96
	Med	$35.44	$35.90	$36.83
	High	$39.37	$38.34	$40.77
IGCC	Low	$27.67	$28.83	$31.15
	Med	$33.40	$34.56	$36.88
	High	$36.70	$37.98	$40.17
Coal	Low	$31.24	$32.69	$35.59
	Med	$37.99	$39.44	$42.34
	High	$41.72	$43.17	$46.08

The life-cycle costs for CO_2 capture and storage technologies do not necessarily reflect the capital and operating costs that are used as inputs for CIMS (Section 4.4). In reviewing input data, one would expect the life-cycle cost for NGCC with CO_2 capture and storage to be significantly lower than the other two capture and storage technologies. Instead they are equal to IGCC life-cycle cost. This is due to the addition of an intangible cost parameter (see section 3.2.3) to the life-cycle cost of natural gas technologies to better reflect industry's perception of natural gas technologies and the financial risk they associate with fluctuating natural gas prices. This intangible parameter causes the life-cycle cost for NGCC technologies, with CO_2 capture and storage, to be similar to other capture and storage technologies, even though their capital and operating costs are significantly lower.

The life-cycle costs for the two remaining CO_2 capture and storage technologies reflect their capital costs. For IGCC, with CO_2 capture and storage, its life-cycle cost is lower than the cost for coal with CO_2 capture and storage, due to IGCC's lower capital and operating costs per unit of power output when compared with coal.

5.1.2 Life-cycle Costs for Competing Technologies

CO_2 capture and storage technologies compete for market share against several other technologies based on their life-cycle cost. The costs ($/GJ) for competing technologies—renewables in particular—are significantly lower than the life-cycle costs for CO_2 capture and storage technologies (Table 5.2).

Table 5.2 Life-cycle Costs ($/GJ) for competing technologies under different tax rates (base and shoulder competition).

Technology	CO_2 Tax Rate				
	No tax	$10 tax	$50 tax	$150 tax	$250 tax
Coal - CO_2 C&S (medium scenario)	$37.99	$38.52	$39.44	$42.34	$45.62
NGCC – no CO_2 capture & storage	$16.00	$16.92	$20.64	$29.92	$39.20
Small Biomass	$16.36	$16.36	$16.36	$16.36	$16.36
Small Hydro	$14.74	$14.74	$14.74	$14.74	$14.74
Wind	$17.68	$17.68	$17.68	$17.68	$17.68
Geothermal	$18.26	$18.26	$18.26	$18.26	$18.26

This is due to lower up-front capital costs of renewables relative to CO2 capture and storage technologies, the 20% discount rate used in calculating life-cycle costs for electricity sector technologies, and the GHG emissions from various facilities.

Capital costs per unit of energy ($/GJ) for capture and storage technologies are significantly higher than for renewable technologies (Table 5.3). When the capital costs are annualized, using the 20% discount rate as part of the life-cycle cost calculations, the difference between the cost for renewables and CO_2 capture and storage increases (Table

5.2). The discount rate reflects a consumers' or firms' trade-off between initial capital costs and future savings in fuel efficiency, operating costs, and/ or CO_2 tax credits when selecting a new technology. A higher discount rate, such as 20%, translates into consumers or firms being less willing to pay high up-front capital costs to save future expenditures, either in lower operating costs, fuel efficiencies, or CO_2 taxes. Because the initial capital costs for constructing a capture and storage facility are much higher than those for constructing a wind farm or a small biomass facility, these smaller and cheaper facilities are preferred over larger capture and storage facilities.

Table 5.3 Capital costs per unit of energy production for renewables and capture and storage.

Technology	Biomass	Wind	Geo-thermal	Coal +CO_2 C&S	NGCC +CO_2 C&S	IGCC +CO_2 C&S
Capital ($/GJ)	$75	$84	$86	$139	$63	$124

Life-cycle costs for CO_2 capture and storage facilities are influenced by changes in the CO_2 tax rate; renewables are not. As tax rates increase, the life-cycle costs for small biomass, geothermal, and wind (renewables) remain the same, as they do not produce any CO_2 emissions. NGCC facilities, which do produce CO_2 emissions, experience a life-cycle cost increase. Thus they would become less competitive relative to both renewable technologies and facilities with CO_2 capture and storage at higher tax rates.

5.1.3 Life-cycle Costs for Retrofitting Technologies

Existing coal facilities, when retrofitted with CO_2 capture and storage have lower life cycle costs at higher tax rates than both its competitor (NGCC) and the base technology (coal) (Table 5.4). This is due to both the base technology and the retrofit competitor producing significantly larger CO_2 emissions than those facilities retrofitted with capture and storage. Thus as tax rates on CO_2 emissions increase and a greater weighting is placed on the emissions of each technology, CO_2 capture and storage becomes more competitive.

Table 5.4 Life-cycle costs for retrofit and replacement technologies.

tax rate	Coal	NGCC	C&S – low	C&S – med	C&S - high
$10	$12	$16	$20	$24	$26
$50	$24	$19	$21	$25	$27
$150	$53	$29	$24	$28	$30
$250	$82	$38	$26	$30	$33

5.2 Market Capture

CO_2 capture and storage's portion of the market share is based on the life-cycle costs of competing technologies. Because the life-cycle costs for CO_2 capture and storage technologies are much greater than competing renewable technologies, they fail to capture any of the new base-load electricity-sector market. However, in the shoulder-load competition, CO_2 capture and storage technologies are able to gain a small portion of the new market share at higher tax rates, as they are only competing with the higher CO_2 emitting NGCC, Single Cycle Gas Turbines, and Pulverized Fluid Bed Coal (PFBC) technologies (Figure 5.1).

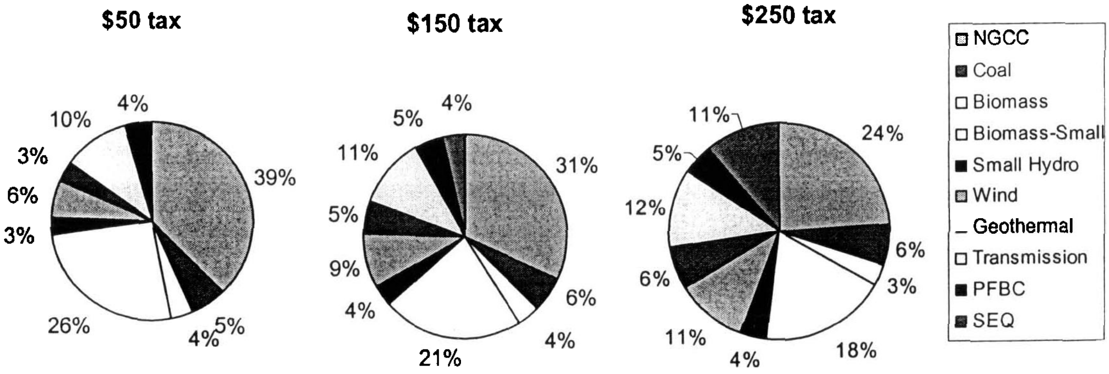

Figure 5.1 New market share (base & shoulder) captured by different electricity supply technologies.

While CO_2 capture and storage technologies gain a small portion of the market- share under the new market competitions (~4000 TJ), it is under the retrofit competition that these technologies have the greatest impact (Figure 5.2). This is particularly evident under higher tax rates, when lower GHG producing CO_2 capture and storage technologies have lower life-cycle costs relative to their competitor (NGCC). However, at lower tax rates, such as the $10 and $50 tax, CO_2 capture and storage technologies acquire very little market share while NGCC captures more. This is due to NGCC being less expensive than CO_2 capture and storage while producing significantly less GHG emissions than the base coal technology.

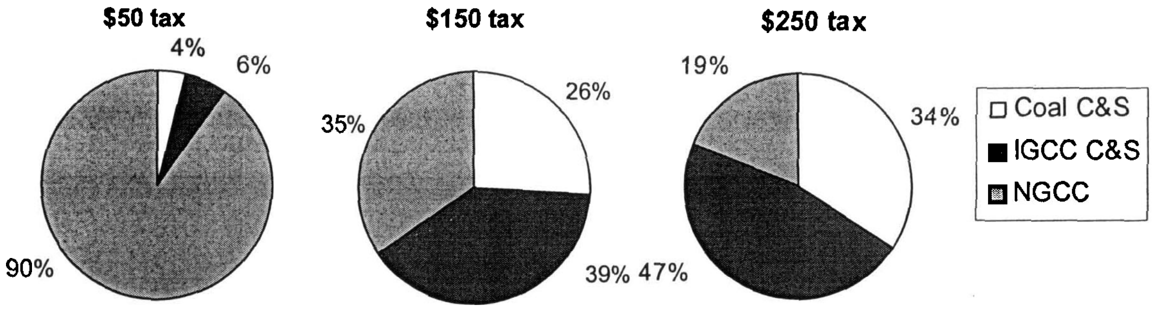

Figure 5.2 Electricity produced (TJ) and percentage of market share (%) captured by CO_2 capture and storage in Alberta and Saskatchewan for the retrofit competition

Scenario assumptions also impact the amount of market share gained by CO_2 capture and storage technologies. At the $50 tax rate, when the low-cost scenario assumptions are applied, CO_2 capture and storage technologies capture 14% of the total market share when both the new market and retrofit market shares are totalled (Figure 5.3). However, using the medium-cost scenario assumptions, they achieve only 2% of the market share. Indeed, in the medium-cost scenario, CO_2 capture and storage technologies do not gain significant market-share until the $150 tax rate is reached, when their life-cycle costs are $1/GJ less than retrofitting with NGCC. The high-cost scenario is similar to that of the medium-cost scenario, with CO_2 capture and storage gaining market share under tax rates greater than \$150. Thus the different assumptions applied to each scenario, and particularly to the low-cost scenario, influence the ability of CO_2 capture and storage facilities to gain market share in the Alberta and Saskatchewan electricity sectors.

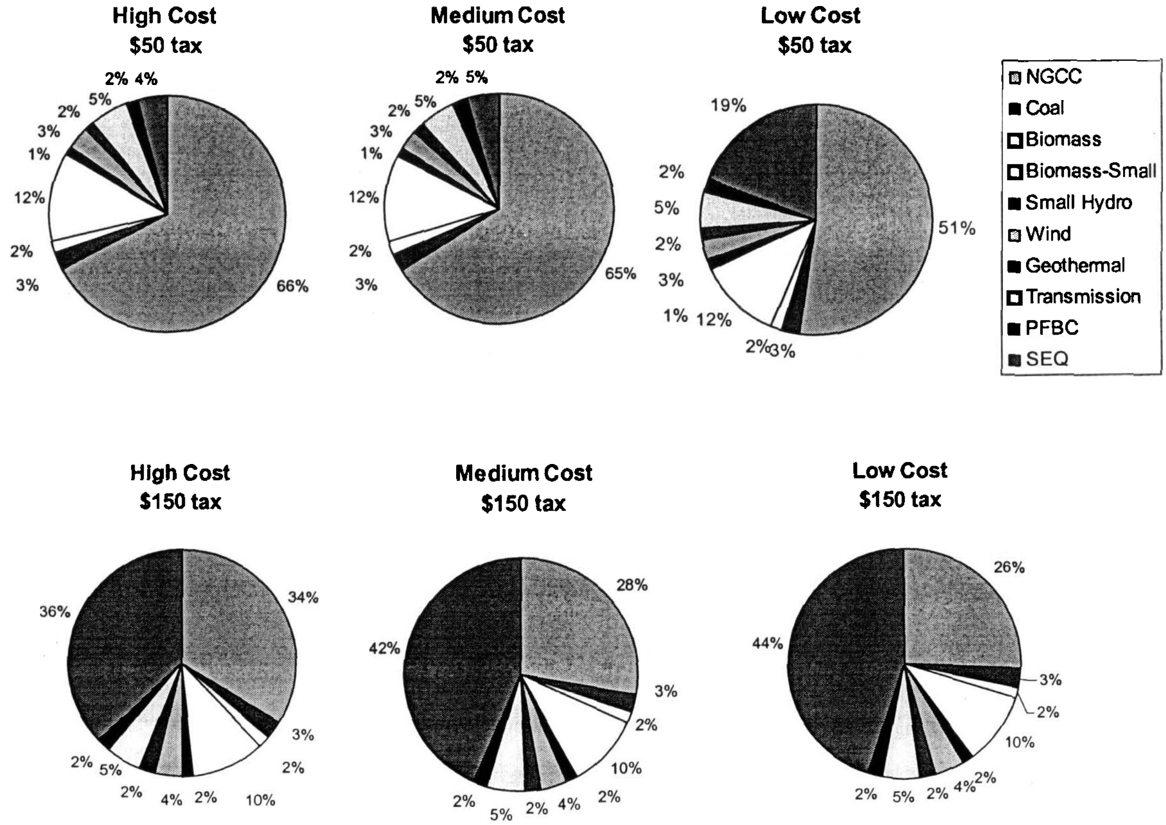

Figure 5.3 Electricity produced (TJ) and percentage of market share (%) captured by CO_2 capture and storage in Alberta and Saskatchewan.

5.3 Meeting Kyoto

The differences among the three scenarios in the market penetration of CO_2 capture and storage technologies impacts upon the total cost of meeting Canada's Kyoto Target.

5.3.1 Canada-Wide Target

According to simulations using CIMS with base assumptions, a tax rate greater than \$150/t CO_2 is required for Canada to meet a 181 Mt of CO_2 reduction target (Figure 5.4).

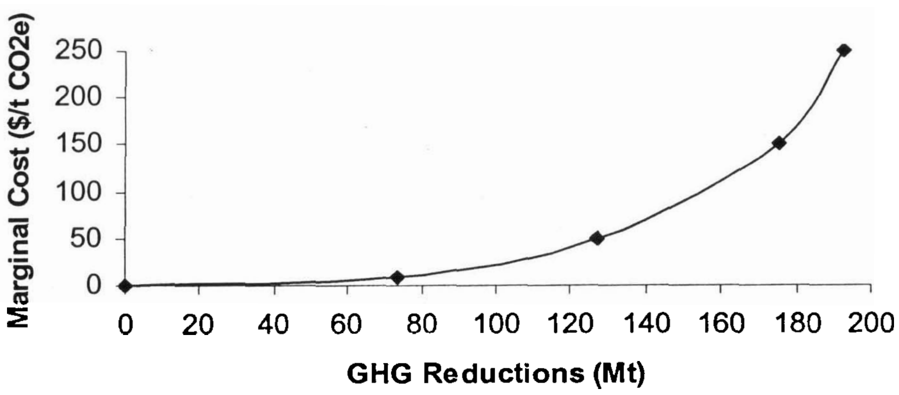

Figure 5.4 GHG abatement emissions cost curve for the Canadian economy to 2010

Under these higher tax rates, CO_2 capture and storage technologies gain market-share via the retrofitting competition and play a major role in reducing GHG emissions from the Canadian electricity sector (Figure 5.5).

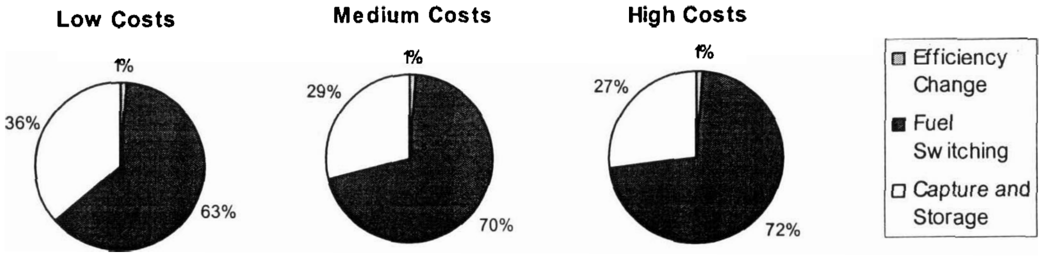

Figure 5.5 Electricity Sector GHG Reductions attributed to CO_2 capture and storage (\$150 tax)

As the cost for CO_2 capture and storage technologies increase, the percentage of total reduced emissions attributed to these technologies decrease. This decrease in reduced GHG emissions is similar to the decrease in the percentage of the electricity-sector market captured by these technologies. However, the decrease in emissions reduction between the two scenarios is significantly less than the percentage difference in life-cycle costs for CO_2 capture and storage among the different scenarios. For example, between the medium-cost and the low-cost scenarios, life-cycle costs increase by 17%, while the amount of CO_2 reductions attributed to CO_2 capture and storage decreases by only 7%. This is because the retrofit market-share competition is based on the difference among the life-cycle costs for NGCC, coal, and capture and storage technologies. When capture and storage technologies loose market share, NGCC technologies take their place in retrofitting coal facilities and the total amount of GHG's reduced in the electricity-sector drops. This causes the percentage of emissions attributed to CO_2 capture and storage to remain high.

The increased cost of retrofitting with CO_2 capture and storage under the higher cost scenarios causes a decrease in GHG emissions reductions, increasing the cost—or permit trading price—required to meet Canada's Kyoto target (Table 5.5).

Table 5.5 Permit Price, GHG Reductions, and proportion of Canada's Reductions attributed to CO_2 capture and storage.

Scenario	GHG Reduced by C&S Technologies (Mt)	Total GHG Reduced (Mt)	Permit Trading Price ($/t$CO_2$)	Proportion of Canada's GHG Reductions (%)
Low Cost	30.34	181	164	17.28
Medium Cost	24.10	181	172	13.92
High Cost	23.15	181	176	12.96

*GHG Reductions (Mt) are the amount of GHG reductions attributed to the implementation of CO_2 capture and storage technologies.

For the low cost scenario, a tax rate of greater than \$164/t CO_2 is required to reach the 181 Mt target; while a \$176/t CO_2 tax is required to meet this target under the high-cost scenario. This \$12/t CO_2, or seven percent difference in tax rates, is greater than the twenty-five percent difference in the life-cycle cost for CO_2 capture and storage technologies between the low- and high-cost scenarios (\$24/GJ vs. \$30/GJ). The difference between these two values (7% vs. 25%) is due to two things. One is that NGCC captures the portion of the retrofit market not absorbed by CO_2 capture and storage technologies. Secondly, more renewable technologies are implemented in the new market competition due to increased tax rates.

However, the difference between the three scenarios is not visible in the cost curve presented in Figure 5.6, primarily due to the steep slopes of the scenario curves at the 181 Mt reduction point, and the small difference (7%) among the scenarios.

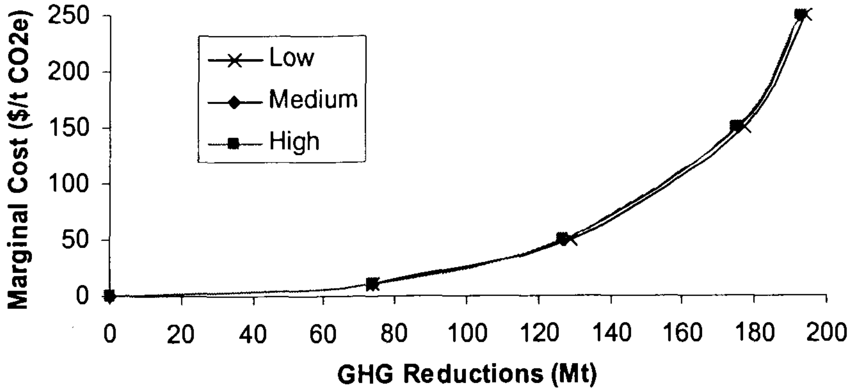

Figure 5.6 The GHG abatement emissions cost curve for the Canadian economy to 2010

5.3.2 Sector-Specific Targets

Differences among the scenarios are more visible when viewing only the data from the electricity sector (Figure 5.7).

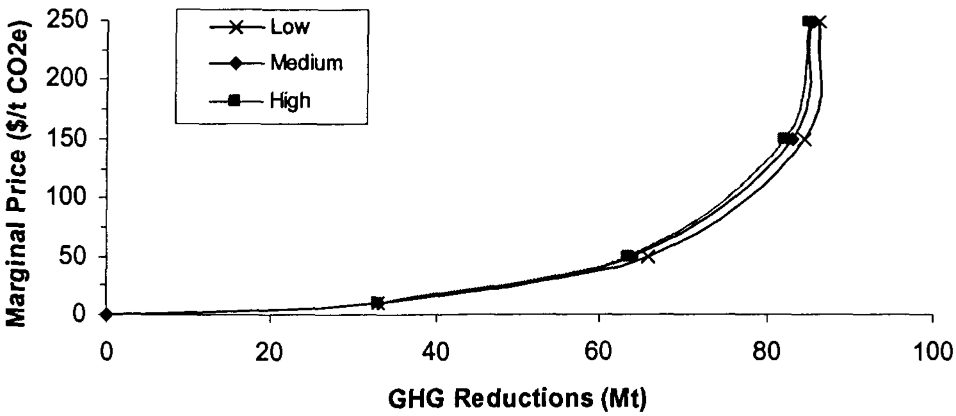

Figure 5.7 The GHG abatement emissions cost curve for the Canadian electricity sector to 2010.

The Canadian government may negotiate its CO_2 permit trading system on a sector-by-sector basis, as it is currently proposing in its Climate Change Plan for Canada. If this were the case, the cost assumptions associated with the implementation of CO_2 capture and storage technologies may have a large impact on the cost for Canada's Electricity Sector to meet its reduction targets. However, this depends on the electricity-sector target. If the sector target is set at 36.8 Mt CO_2 reduction by 2008-2012, then it is unlikely that any capture and storage technologies will be implemented. This occurs because the tax-level required for such a reduction is slightly higher than $10/tCO2e; CO_2 capture and storage technologies do not penetrate the market at this level. If the sector target is set at 77.5 Mt of CO_2, as was proposed by the federal government's national climate change process, then the price of capture and storage technologies could play a major role in the cost of CO_2 reductions, with the shadow price varying from $92/t CO_2 to $112/t CO_2, depending on the future cost of CO_2 capture and storage.

5.3.3 Provincial Sector-Specific Targets

Differences among the scenarios are most visible when viewing the data for the two provincial electricity sectors in which CO_2 capture and storage technologies are available for implementation; Alberta and Saskatchewan (Figures 5.8 and 5.9).

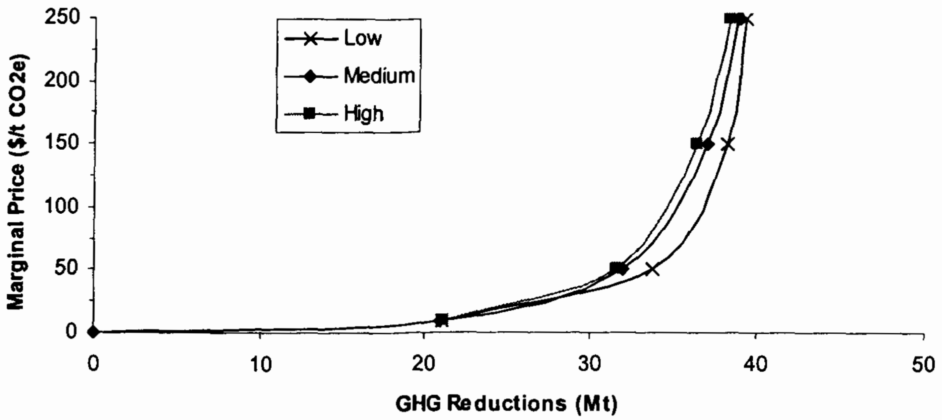

Figure 5.8 The Alberta electricity sector's GHG abatement emissions cost curve up until 2010.

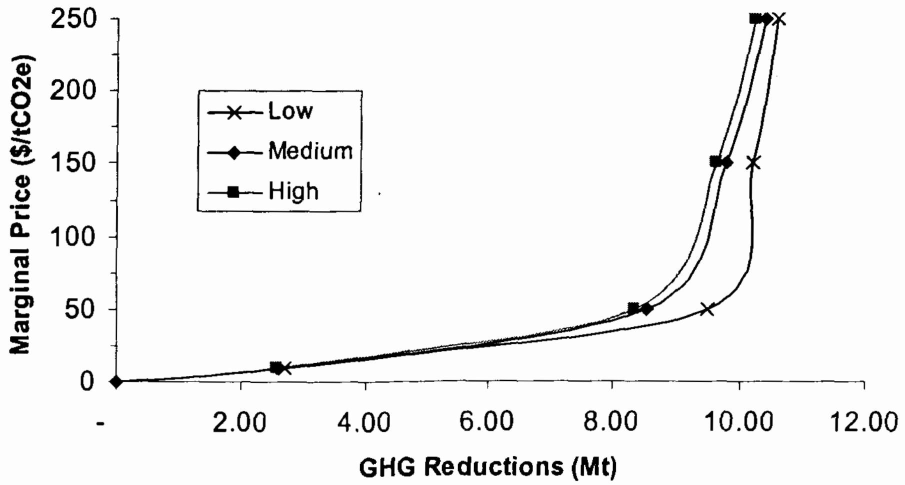

Figure 5.9 The Saskatchewan electricity sector's GHG abatement emissions cost curve up until 2010.

Upon closer inspection of the Alberta and Saskatchewan electricity sectors, CO_2 capture and storage technologies in the low cost scenario are having the greatest impact on the GHG abatement emissions cost curve at the $50 tax. While also having an impact at the $150 and $250 tax rates, the percentage difference among the scenarios are not as great as at the $50 tax rate. Under the low cost scenario and a $50 tax rate, CO_2 capture and storage technologies are only slightly more expensive than their direct competitor, NGCC. Life-cycle costs under the other two scenarios remain too high ($6/GJ greater than NGCC) for any significant market penetration to occur (<5%). It is the 20% difference in the percentage of retrofit market share captured by capture and storage technologies between the low cost and medium cost scenarios that results in an increase of greenhouse gas reductions by 15% in Saskatchewan and 9% in Alberta. Under the $150 tax, the difference in reductions achieved between these scenarios decreases to 5% in Saskatchewan and 7% in Alberta. This is due to the amount of CO_2 emissions for each scenario being the same. At the higher tax rates, when the CO_2 tax rate is applied equally to each scenario, the cost to each scenario is the same, decreasing the percentage difference among the scenarios and also reducing the difference among the amount of GHG's reduced at a given tax rate.

In observing these specific areas of the Canadian economy, the impact that different scenario assumptions have on CO_2 capture and storage market penetration depends on the taxation rate applied.

5.4 Comparison to past studies

While initial input costs for the medium-cost scenario come from an average taken from fourteen different studies, the life-cycle costs for CO_2 capture and storage technologies are significantly different from other modelling oriented studies, particularly Keith and Johnson 2001 and Williams 2002. The reasons for this vary depending upon the study.

The costs for CO2 capture and storage are lower in Keith and Johnson's study, in part because they use an annual capital charge rate of twelve percent while this study uses a twenty percent discount rate. Also, Johnson and Keith use capital cost inputs that are at the lower end of the range found in the literature search for this paper, similar to those in the low cost scenario.

NGCC technologies that include capture and storage are one exception to this generalization. In CIMS, an intangible cost is added to NGCC technologies to represent the perceived risks associated with these technologies, resulting in NGCC technologies being more expensive in our modelling results relative to the Keith and Johnson study.

In the second study (Williams 2002), data are only available for IGCC with CO_2 capture and storage, as the study primarily focuses on generating hydrogen from IGCC and NGCC technologies. In comparing assumptions made in William's study with CIMS parameters, the discount rate (10% versus the 20% used in CIMS), the capacity utilization (80% versus 75% in CIMS), power generation per given input (38% vs. 36% in CIMS), and the Canadian exchange rate lead to a lower life-cycle cost for the Williams study relative to CIMS. In comparing expenses for this technology between the two studies, the capital cost in the Williams study is comparable to those used in the low cost scenario. However, the IGCC facility used in the Williams study generates 50 MW less power than the facility used in CIMS. Once all of these factors are taken into consideration, the CIMS life-cycle cost under the medium-cost scenario are similar to those used in Williams study if the same parameters are applied.

5.5 Influence of Time Frame

Another factor that influences Canada's ability to reduce GHG's is time frame. Technology turnover and replacement takes time, particularly for large facilities like power plants, which often operate beyond their initially specified life-span (Lempert et al. 2002). By extending the time period in which Canada can meet its 181 Mt target from 2010 to 2030, and using the medium-cost scenario for CO_2 capture and storage costs, a much greater reduction in GHG's is achieved for a given marginal cost or tax rate (Figure 5.10).

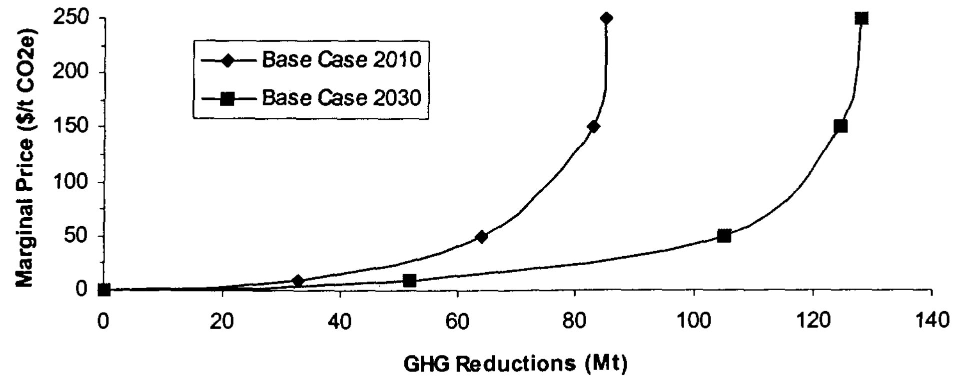

Figure 5.10 Canadian Electricity Sector's GHG abatement emissions cost curve to 2010 and to 2030.

While the reductions achieved by 2030 are much greater than those achieved by 2010, almost all of the additional reductions (those achieved between 2010 and 2030) occur in Ontario and the Maritimes. Very few additional reductions are achieved in Alberta and Saskatchewan; none are through the implementation of CO_2 capture and storage facilities. This is due to CO_2 capture and storage facilities, which enter the electricity market primarily through the early retrofitting of older facilities, not capturing any market share in the post 2010 new-market competition as they are out competed by renewable technologies. The costs assumptions for the three different CO_2 capture and storage scenarios have very little impact on the reductions achieved in the electricity sector when using a 2030 timeframe (Figure 5.11).

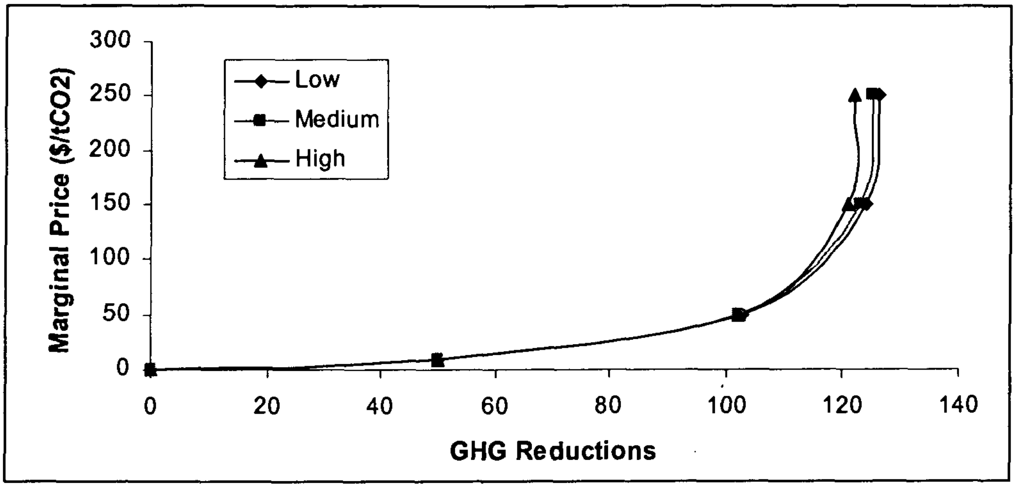

Figure 5.11 Canadian Electricity Sector GHG abatement emissions cost curve to 2030.

The total number of operating capture and storage facilities in 2030 is less than the number in 2010. This decrease occurs as technologies, which were originally retrofitted with CO_2 capture and storage, are retired and replaced by renewable technologies such as geothermal, wind, and biomass. Because retrofitting plays a smaller role in the 2030 time period, the percentage of GHGs reduced by capture and storage technologies decreases and the different scenarios have less impact on Canada's ability to meet Kyoto.

5.6 An additional scenario

Based on a review of these initial three scenarios, a fourth scenario was designed to illustrate the potential impact the worst-case future scenario for CO_2 capture and storage technologies might have on Canada's ability to meet Kyoto. For this scenario a two-fold increase in both capital and operating costs were applied to the three capture and storage technologies. This scenario was meant to reflect a future for capture and storage technologies which proved to be geologically difficult in the storage stage, prohibitively expensive in the capture stage, and unacceptable to the public. A similar situation was observed for the introduction of nuclear technologies, during which capital cost increased three fold over initial predictions. While a sudden and large CO_2 leak can cause rapid death to people in the immediate area, the long-term health impacts of dispersed CO_2 are much different than those from a radiation leak at a nuclear facility. To better reflect this, the fourth scenario involves a two-fold increase in capital and operating costs over the medium-cost scenario. The impact that a two-fold increase in the cost of storage has on the electricity sector relative to the medium cost scenario is illustrated in Figure 5.12.

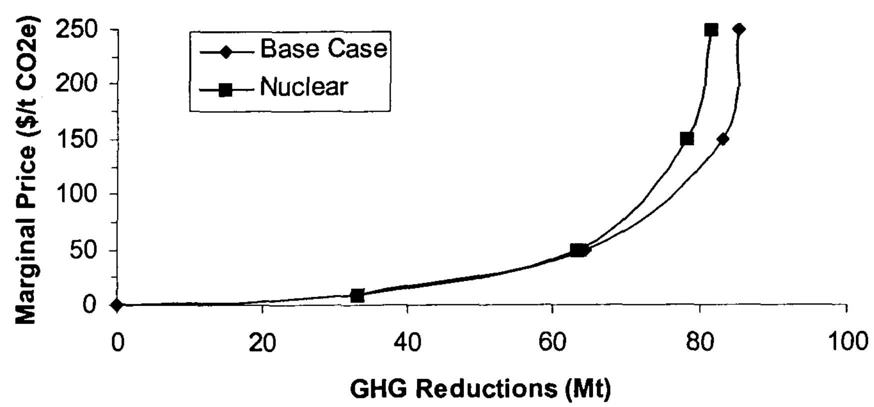

Figure 5.12 Canadian Electricity Sector GHG abatement emissions cost curve to 2010

The impact of this two fold increase in costs is that CO_2 capture and storage technologies at the $250 tax rate account for less than 50% of the market share gained in the base case scenario. At the $150 tax rate the market share for capture and storage drops to three percent of the electricity market. This increases the cost of meeting the

Kyoto target from \$172/t CO_2 to \$188/t CO_2 under the medium-cost scenario. This nine percent increase in costs indicates the impact that not having CO_2 capture and storage technologies available (3% of market share) could have on Canada's ability to achieve its Kyoto target.

5.7 Scenario Likelihoods

The probability of experiencing these three scenarios is difficult to predict. However, with the large investment that both the United States government and several large oil and coal producers are putting into developing these technologies, it is likely that capital costs for these technologies will fall quickly.

But it is the effectiveness of storing CO_2 in saline aquifers, not the costs for CO_2 capture that will most likely be critical in determining the public's willingness to accept this technology. The work needed to better understand the storage stage of CO_2 capture and storage is extensive; numerous geological attributes that can vary throughout an aquifer need to be considered when selecting a site, and an effective monitoring system needs to be designed to track CO_2 movement underground. As long as an appropriate level of investment is made in these areas, and the first series of demonstration projects is a success, which appears likely given the experience with the Sleipner T Platform in Norway, the cost for these technologies should remain at the medium-cost scenario and drop over time with increased experience. Because at least four full-scale CO_2 capture and storage facilities recently received funding from both national governments and the business community, it is highly likely that the costs will drop within the next five-year period, so long as initial precautions are taken. Probabilities that could be used for the future cost of CO_2 capture and storage are listed in Table 5.6

Table 5.6 Future Probability* for Cost of CO_2 Capture and Storage Technologies

Scenario	Current Price	Price in 5-10 Years
Low	0.30	0.60
Medium	0.50	0.10
High	0.15	0.20
Nuclear	0.05	0.10

* Future Probabilities have a maximum value of 1.0 (or 100%) and a minimum of 0 (0%).

Regardless of the future development of this technology, it is highly unlikely that costs will remain the same. New, more efficient, capture processes are being developed by industry. Storage options are being more thoroughly examined by academics and governments, and policy development around the promotion and implementation of these technologies is being pushed ahead by various national governments. These include the USA, Canada, Britain, Germany, Denmark, and Australia to name a few. The IPCC is also beginning to examine CO_2 capture and storage as a possible climate change mitigation option and has formed a working group to commission a report on the subject.

There are two potentially major problems that may cause the cost for these technologies to increase dramatically. One is if adequate precautions are not taken, and a large CO_2 release occurs, killing people. This, however, is highly unlikely, particularly if appropriate site selection and monitoring is carried out prior to facility construction. The second problem relates to water use. CO_2 capture and storage facilities require significantly more water than the technologies they are replacing, due to additional cooling processes in the regeneration of solvents and the compression stage. With water scarcity becoming an ever larger issue, it is questionable whether certain regions could handle increased water demand, particularly Alberta and Saskatchewan, where drought and water availability are a major issue. The impact of this on future costs is extremely difficult to predict.

5.8 Areas of Future Research

There are numerous potential areas to expand this research project. Three notable future research questions that would increase our understanding of the role that CO_2 capture and storage technologies could play in helping Canada achieving its Kyoto Target include:

- What impact does changing the variance parameter, particularly in the retrofit competition, have on the ability for CO_2 capture and storage technologies to capture electricity market share?

- What impact would CO_2 capture and storage technologies have on Canada's ability to meet the Kyoto Protocol if these technologies were implemented in other areas of the Canadian economy, including oil and gas extraction?

- What role do these technologies play if, instead of producing electricity, they generate hydrogen which can then be traded within the model?

- What impact would these technologies have on Canada's ability to meet Kyoto if all of the GHG emissions, including those from parts fabrication and construction where included in the electricity-supply component of CIMS?

Because most CO_2 capture and storage technologies enter the market through retrofit competitions, the retrofit variance parameter, which is set at 0.4, impacts the market share captured by these technologies. This CIMS parameter, which is meant to reflect market heterogeneity determines the width of a probability distribution applied to single-point cost estimates for retrofitting technologies. If v is set so that the distribution is zero, then the lowest-cost technology captures 100% of the market. If the distribution is set to be quite wide, two competing technologies could each gain 50% market share, even though one is much cheaper than the other. While the variance parameter was set at 0.4 for this study, reflecting expert opinion of market heterogeneity to retrofitting electricity supply facilities, there are no empirical literature or firm preference surveys for CO2 capture and storage to support this selection. More work is needed to determine what the appropriate variance parameter is for retrofitting technologies, given the large influence that this group of technologies has on the cost of reducing Canada's GHG emissions.

CO_2 capture and storage technologies could also be applied to technologies in other sectors of the Canadian economy. Alternative CO_2 capture and storage applications include: CO_2 capture from natural gas flaring or from oil sands gas extraction, and CO_2 storage in enhanced oil or gas recovery operations. All are technologically possible and potentially cheaper than capture from power plants and storage in saline aquifers. Lower costs for these capture options are due to the increased concentration of CO_2 being released from these processes, and the storage option is also more economically due to the added value of pumping CO_2 into oil and gas reservoirs to increase the rate of oil or gas recovery. However, for enhanced recovery operations, not as much CO_2 remains trapped in oil and gas reservoirs. The Sleipner T Platform in the North Sea demonstrates the effectiveness of collecting excess CO_2 from natural gas production, which would normally be released directly into the environment, and subsequent storage in saline aquifers. These additional options for implementing CO_2 capture and storage technologies were not examined in this research project but would provide an additional way for CO_2 technologies to assist current fossil fuel extraction processes in meeting their Kyoto targets.

Another recently proposed option that would involve capture and storage technologies is the use of coal in an IGCC-type facility to create hydrogen. In this instance, the resulting CO_2 would be stored either in saline aquifers or used in enhanced oil and gas recovery operations. This type of power facility has never been built and hydrogen does not yet possess enough market share to be a viable alternative for meeting the Kyoto agreement by 2010. However, perhaps by 2030 this technology, which according to some initial forecasts would be equivalent in cost to current-day NGCC technologies, could provide a viable, cheaper, and cleaner option than applying CO_2 capture and storage to existing power plants.

While the CIMS electricity component includes the CO_2 emissions produced through the operational practices of various technologies; it does not include the emissions created from facility construction. This is in part because of the way in which CO_2 charges are to be applied to different economic sectors—end-of-pipe rather than full life-cycle—which is reflected in CIMS structure. CO_2 emissions from transportation, steel fabrication, and cement production, all of which might be part of the construction of a CO_2 capture and storage facility, are included in other components of CIMS; not the electricity component. However, if a full life-cycle analysis was to be conducted on CO_2 capture and storage facilities their total emissions would probably be somewhat greater than a modern coal plant, the basis for most facilities engineering specifications. A modern coal plant can produce between 790 and 1182 grams of CO_2/kWh depending on the sources of coal used and other operating parameters (Meier, 2002). This is significantly greater than the full life-cycle GHG emissions from NGCC facilities (389-511 gCO_2/kWh), Biomass (15-101 gCO_2/kWh), and Wind (7-124 gCO_2/kWh) (Meier, 2002). If a CO_2 tax where to be applied to the full life-cycle emissions of a power generating facility and this was reflected in CIMS this might further prevent CO_2 capture and storage facilities from gaining market share.

6. Conclusion

CO_2 capture and storage technologies only gain market penetration when a carbon tax is applied to the electricity-sector market. However, the level to which CO_2 capture and storage technologies penetrate the electricity market depends on the level of taxation and the variety of uncertainties that are taken into account when calculating the cost of these technologies. For example, if it is assumed that the capital costs for these technologies follow the typical learning curve, and decrease by 17%; the relative power output increased due to improved process refinement (low-cost scenario), and that a $50 tax rate is applied to the Canadian market, this study suggests that these technologies could gain 14% of the Alberta and Saskatchewan electricity market. However, if the cost escalates due to an increased need for monitoring to achieve public acceptability, and an environmental assessment process is conducted for facility siting and construction (high cost scenario), these technologies would not gain any market share at a $50 tax.

But what does this mean for Canadians and our ability to meet our Kyoto target? According to this study based on CIMS simulations, for Canada to reduce 181 Mt of greenhouse gases by 2010, relative to a business-as-usual forecast, an economy-wide tax of $164/t CO_2 would be required under the low-cost scenario and a $176/t CO_2 under the high-cost scenario. This seven percent increase in the cost of meeting Kyoto is due to different cost assumptions associated with one group of technologies. Furthermore, should the worse-case nuclear scenario occur for these technologies, this price could rise to $188/t CO_2, a 15% increase over the low-cost scenario.

If Canada chooses to negotiate CO_2 reductions by sector, the impact of these technologies on the price of carbon credits would depend on the reduction target selected. If a 33.8 Mt reduction in greenhouse gas emissions were selected as the target (the amount of GHG's this sector should reduce based on its emissions in 1990) a \$10/t CO_2 tax would be required. At this low tax rate, no capture and storage technologies would be implemented. However, if a 77.5 Mt reduction is used, as was suggested by the National Climate Change Process, the cost of the carbon tax required to meet this target, would vary from \$92/t CO_2 in the low-cost scenario to \$112/t CO_2 under the high-cost scenario. The fourth scenario, based on a nuclear-type future for CO_2 capture and storage, would increase the necessary tax to \$143/t CO_2, or a fifty percent increase over the low-cost scenario to achieve the 77.5 Mt target.

However, despite the large sectoral impact of CO_2 capture and storage technologies at high tax rates, these technologies are primarily penetrating the electricity sector through the retrofitting of higher polluting facilities. They are capturing only a very small portion of the new or replacement technology markets as they are out-competed by renewables in the base-load market and there a re few shoulder-load facilities in need of replacement. At lower tax rates, CO_2 capture and storage technologies are less efficient and thus out-competed by cheaper and higher emitting NGCC and single-gas-turbine power stations.

Based on these findings, the Canadian government, in attempting to meet Kyoto by 2010, should focus on retrofitting older coal facilities in the short term. But that focus should be switched to renewable technologies as its best long-term reduction strategy for the post-Kyoto period when even greater reductions in GHG emissions are likely to be negotiated.

7. References

Allard P., D. Djlevic, C. Delarue. 1989. Origin of carbon dioxide emanation from the 1979 Dieng eruption, Indonesia: Implications for the origin of the 1986 Nyos catastrophe. *Journal of Volcanology and Geothermal Research* 39:195-206.

Azar, C., and H. Dowlatabadi. 1999. A review of technical change in assessment of climate policy. *Annual Economic Review of Energy and the Environment* 24:513-544.

Bachu, S. 2000. Sequestration of carbon dioxide in geological media: criteria and approach for site selection in response to climate change. *Energy Conversion and Management* 41:953-970.

—. 2001. Geological Sequestration of Anthropogenic Carbon Dioxide: Applicability and Current Issues. Chap. 15 in *Geological Perspectives in Climate Change*, edited by L. C. Gerhard, W. E. Harrison, and B. M. Hanson. Tulsa: American Association of Petroleum Geologists.

Bachu, S., W. D. Gunter, and E. H. Perkins. 1994. Aquifer Disposal of Carbon Dioxide: Hydrodynamic and Mineral Trapping. *Energy Conversion and Management* 35:369-279.

Bolland, O. and S. Saether. 1992. New Concepts for Natural Gas Fired Power Plants which Simplify the Recovery of Carbon Dioxide. *Energy Conversion and Management* 33:467-475.

Booras, G. S. and S. C. Smelser. 1991. An Engineering and Economic Evaluation of Carbon Dioxide for Fossil Fuel Fired Power Plants. *Energy* 16:1295-1305.

Bosello, F., C. Carraro, and C. Kemfert. 1998. “Advances of Climate Modelling for Policy Analysis” [cited Spetember 21, 2002]. Available from www.feem.it/web/activ/wp/abs98/89-98.pdf; INTERNET

Canada. 2002. “Climate Change, Achieving Our Commitments Together: Climate Change Plan for Canada.” [cited 28 October 2003] Available from http://www.climatechange.gc.ca./plan_for_ canada/index.html; INTERNET.

Chapel, D., J. Ernest, and C. Mariz. 2001. Recovery of CO2 from Flue Gases: Commercial Trends. Paper read at 1st National Conference on Carbon Sequestration, 14-17 May, Washington, D.C.

Claeson, U. 1999. Experience curves for policy making – the case of energy technologies. Paper read at IEA International Workshop, 4 October, Stuttgart, Germany.

Cleveland, C., and M. Ruth. 1999. Indicators of Dematerialization and the Material Intensity of Use. *Journal of Industrial Ecology* 1999:15-50.

David, J. 2000. Economic Evaluation of Leading Technology Options for Sequestration of Carbon Dioxide, in Engineering Systems Division. Master's Thesis, Massachusetts Institute of Technology.

Delionback, L. M. 1995. Learning Curves and Progress Functions. In *Cost Estimators Reference Manual,* edited by R. D. Stewart, R. S. Wyskida, and J. D. Johannes. New York: John Wiley and Sons Inc.

Doctor, R. D., J. C. Molburg, N. F. Brockmeier, L. Manfredo, V. Gorkhov, M. Ramezan, and G. J. Stiegel. 2001. Life-cycle Analysis of a Shell Gasification-Based Multi-Product System with CO2 Recovery. . Paper read at 1st National Conference on Carbon Sequestration, 14-17 May, Washington, D.C.

Doctor, R. D., J. Molburg, and P. Thimmapuram. 1997. Oxygen Blown Gasification Combined Cycle: Carbon Dioxide Recovery, Transport, and Disposal. *Energy Conversion and Management* 38:S575-S580.

Doherty, P., and R. Harrison. 1992. Techno-economic modeling of the underground disposal of carbon dioxide. In the *Underground Disposal of Carbon Dioxide: Final Report of Joule II* Project No. CT92-0031, edited by S. Holloway. Nottingham: British Geological Survey.

Dooley, J., J. Edmonds, and M. Wise. 1998. The Role of Carbon Capture and Sequestration in a Long-term Technology Strategy of Atmospheric Stabilisation. Paper read at 4th International Conference on Greenhouse Gas Technologies, 30 August – 2 September, Interlaken, Switzerland.

Dooley, J., J. Edmonds, R. Dahowski, and M. Wise. 2002. Modelling Carbon Capture and Storage Technologies in Energy and Economic Models. Paper read at IPCC Workshop on Carbon Dioxide Capture and Storage, 18-21 November, Regina, S.K.

Dornbusch, R., and S. Fischer. 1981. *Macroeconomics*. Edited by B.E. Lieberman and E. Adams. New York: McGraw-Hill.

Edmonds, J., J. Roop, and M. Scott. 2000. *Technology and the Economics of Climate Change Policy.* Arlington: Pew Center on Global Climate Change.

Farrar C. D., M. L. Sorey, W. C. Evans, J. F. Howle, B. D. Kerr, B. M. Kennedy, B. Y. King, and J. R. Southon. 1995. Forest-killing diffuse carbon dioxide emission at Mammoth Mountain as a sign of magmatic unrest. *Nature* 376:675-677.

Fetter, C.W. 2001. *Applied Hydrogeology*. 4d ed. Upper Saddle River: Prentice Hall.

Fisher, J. 1974. *Energy Crises in Perspective*. New York: Wiley.

Fisher, L, T. Sloan, and P. Mortense. 2002. Costs for Capture and Sequestration of Carbon Dioxide in Western Canadian Geologic Media. Calgary: Canadian Energy Research Institute.

Gottlicher, G. and R. Pruschek. 1997. Comparison of CO_2 Removal Systems for Fossil-Fuelled Power Plant Processes. *Energy Conversion and Management* 38:S173-S178.

Gunter, W. D., S. Wong, D. Chell, and G. Sjostrom. 1998. Large CO_2 sinks: Their role in the mitigation of greenhouse gases from an international nation's (Canadian) and provincial (Alberta) perspective. *Applied Energy* 61:209-227.

Hendriks, C. A., and K. Blok. 1993. Underground Storage of Carbon Dioxide. *Energy Conversion and Management* 34:949-957.

Hitchon, B., W. D. Gunter, G. Thomas, and R. T. Bailey. 1999. Sedimentary basins and greenhouse gases: a serendipitous association. *Energy Conversion and Management* 40:825-843.

Holloway, S. 1997. Safety of the Underground Disposal of Carbon Dioxide. *Energy Conversion and Management* 38:S241-S245.

Hourcade, J. and J. Robinson. 1996. Mitigating factors: Assessing the costs of reducing GHG emissions. *Energy Policy* 24:863-873.

Intergovernmental Panel on Climate Change (IPCC). 2001. *Climate Change 2001, The Scientific Basis*. Vol. 1 of Third Assessment Report of the Intergovernmental Panel on Climate Change. New York: Cambridge University Press.

Intergovernmental Panel on Climate Change, World Meteorological Organization, and United Nations Environment Program (IPCC/WMO/UNEP). 1990. *Impacts Assessment of Climate Change – Report of Working Group II (Summary for Policy Makers)*. Edited by J. T. Houghton, G. J. Jenkins, and J. J. Ephraums. Cambridge: Cambridge University Press.

International Energy Association (IEA). 2000. Experience Curves for Energy Technology Policy. Paris: International Energy Association.

Jaccard, M., J. Nyboer, and B. Sadownik. 2002. *The Cost of Climate Policy*. Vancouver: UBC Press.

Jaccard, M., J. Nyboer, C. Bataille, and B. Sadownik. 2003. Modeling the cost of climate policy: Distinguishing between alternative cost definitions and long-run cost dynamics. *The Energy Journal* 24:49-72.

Jaffe, A. and R. Stavins. 1994. The energy-efficiency gap: What does it mean? *Energy Policy* 22:804-810.

Johnson, T. and D. Keith. 2001. Electricity from Fossil Fuels without CO_2 Emissions: Assessing the Costs of Carbon Dioxide Capture and Sequestration in U.S. Electricity Markets. *Journal of Air and Waste Management* 51:1452-1459.

Joskow, P. and N. Rose. 1985. The effects of technological change, experience, and environmental regulation on the construction cost of coal-burning generating units. *Rand Journal of Economics* 16:1.

Kingston, D. R., C. P. Oishroon, and P. A. Williams. 1983. Global Basin Classification System. *American Association of Petroleum Geologists Bulletin* 67: 2175-93.

Kruse, H. and M. Tekeila. 1996. Calculating the consequences of a carbon dioxide pipeline rupture. *Energy Conversion and Management* 37:1013-1018.

Kyoto Protocol to the United Nations Framework Convention on Climate Change. 1997. Kyoto.

Lanford, H. W. 1972. *Technological Forecasting Methodologies.* New York: American Management Association Inc.

Law, D. S., and S. Bachu. 1995. Hydrogeological and Numerical Analysis of Carbon Dioxide Disposal in Deep Aquifers in the Alberta Sedimentary Basin. *Energy Conversion and Management* 37:1167-1174.

Lempert, R. J., S. W. Popper, S. A. Resetar, and S. L. Hart. 2002. Capital Cycle and the timing of Climate Change Policy. Arlington: Pew Center on Global Climate Change.

Lindeberg, E. 1997. Escape of Carbon Dioxide from Aquifers. *Energy Conversion and Management* 38:S235-S240.

Lindeberg, E. and D. Wessel-Berg. 1997. Vertical Convection in an Aquifer Column under a Gas Cap of Carbon Dioxide. *Energy Conversion and Management* 38:S229-S234.

Lipsey, R., D. Purvis, and P. Steiner. 1991. *Economics* 7d ed. New York: Harper Collins Publishers.

M. K. Jaccard and Associates. 2000. *Integration of GHG Emission Reduction Options using CIMS.* Paper read at National Climate Change Implementation Process, 7-9 October, Vancouver, B.C.

Marion, J., N. Nskala, T. Griffon, and A. Bill. 2001. Controlling Power Plant Emissions: A Long Range View. Paper read at 1st First National Conference on Carbon Sequestration, 14-17 May, Washington, D.C.

McDonald A., and L. Schrattenholzer. 2001. Learning Rates for Energy Technologies. *Energy Policy* 29:255-261.

Meier, P. J. 2002. Life-Cycle Assessment of Electricity Generation Systems and Applications for Climate Change Policy Analysis. Master's Thesis. University of Wisconsin-Madison.

National Climate Change Process (NCCP). 2001. National Climate Change Process (NCCP) [cited 28 October 2003]. Available at http://www.nccp.ca; INTERNET

National Energy Association of the Organization for Economic Cooperation and Development (NEA-OECD). 1992. *Broad Economic Impact of Nuclear Power.* Paris: Organization for Economic Co-Operation and Development.

Riemer, P. W. and W. G. Omerod. 1995. International perspectives and the results of carbon dioxide capture, disposal, and utilization studies. *Energy Conversion and Management* 36:813-818.

Shakow, D. and R. Goble. 1982. Technological Risk Perception and Nuclear Power Costs, The Quantification of Uncertainty. *Technological Forecasting and Social Change* 21:185-199.

Sigvaldason, G. E. 1989. International Conference on Lake Nyos Disaster, Yaounde, Cameroon 16-20 March, 1987: Conclusions and Recommendations. *Journal of Volcanology and Geothermal Research* 29:97-107.

Stewart, R. D. 1995. Detailing Cost Estimating. In *Cost Estimators Reference Manual.* Edited by R. D. Stewart, R. S. Wyskida, and J. D. Johannes. New York: John Wiley and Sons Inc.

Stork Engineering Consultancy. 1999. *Assessment of Leading Technology Options for Abatement of Carbon Dioxide Emissions*. Cheltham: International Energy Association (IEA) - Greenhouse Gas R&D Programme.

—. 2001. *Carbon Dioxide Disposal from Power Stations - Disposal in Aquifers*. Cheltham: IEA Greenhouse Gas Research and Development Program.

United States Department of Energy (US DOE). 1999. Carbon Sequestration: State of the Science. A working paper for road-mapping future carbon sequestration R&D. Washington: US DOE.

Wildenborg, T. 2000. "Costs of Carbon Dioxide Sequestration by Underground Storage." [cited 28 October 2003]. Available from http://www.ieagreen.org.uk/march47.htm; INTERNET

Williams, R. H. 2002. Toward a Hydrogen/Electricity Economy for an Environmentally Constrained World. Paper read at the 22nd Annual North American Conference of the US Association for Energy Economic, 6-8 October, Vancouver, B.C.

Williams, R. H. 2001. Nuclear and Alternative Energy Supply Options for an Environmentally Constrained World: A long-Term Perspective. Paper read at the Nuclear Control Institute's 20th Anniversary Conference: Nuclear Power and the Spread of Nuclear Weapons: Can We Have One Without the Other? 9 April, Washington, D.C.