Assessing the Economic Potential of Carbon Capture and Storage in Canada Using an Energy-Economy Model

by
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Abstract

In this paper I investigate the potential for large-scale deployment of carbon capture and storage in Canada. I collected data on carbon emission point sources across Canada and potential carbon storage sites to estimate how carbon capture and storage costs differ by industry, region and increasing cumulative production nationally. The economic costs for all three aspects—capture, transport and storage—are assembled into regional and national cost curves. These cost curves provide a detailed representation of carbon capture and storage in a technology-rich energy-economy model called CIMS. The model is simulated under various policy scenarios to estimate likely adoption rates of carbon capture and storage and the economic and emissions implications.

Keywords: Carbon capture and sequestration; Hybrid energy-economy models; Climate change policy; CO₂ sequestration supply curve
Acknowledgements

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Mark Jaccard, for his guidance and passion. It is truly inspiring to work with someone so enthusiastic about his work that it is incorporated into his lifestyle and actions. Jotham Peters, for his invaluable technical knowledge. The battle with CIMS would not have been won without your help. John Nyboer, for his Canadian industry expertise and his delicious zucchini relish.

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<th>Description</th>
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<tbody>
<tr>
<td>AEEI</td>
<td>Autonomous Energy Efficiency Index</td>
</tr>
<tr>
<td>CCPC</td>
<td>Clean Coal Power Coalition</td>
</tr>
<tr>
<td>CO₂</td>
<td>Carbon Dioxide</td>
</tr>
<tr>
<td>EMF</td>
<td>Energy Modeling Forum</td>
</tr>
<tr>
<td>EOR</td>
<td>Enhanced Oil Recovery</td>
</tr>
<tr>
<td>ESUB</td>
<td>Elasticity of Substitution</td>
</tr>
<tr>
<td>GHG</td>
<td>Greenhouse Gas</td>
</tr>
<tr>
<td>ICO2N</td>
<td>Integrated CO₂ Network</td>
</tr>
<tr>
<td>IGCC</td>
<td>Integrated Gasification Combined Cycle</td>
</tr>
<tr>
<td>IPCC</td>
<td>Intergovernmental Panel on Climate Change</td>
</tr>
<tr>
<td>LCC</td>
<td>Life Cycle Cost</td>
</tr>
<tr>
<td>LCOE</td>
<td>Levelized Cost of Energy</td>
</tr>
<tr>
<td>NEB</td>
<td>National Energy Board</td>
</tr>
<tr>
<td>NGCC</td>
<td>Natural Gas Combined Cycle</td>
</tr>
<tr>
<td>PC</td>
<td>Pulverized Coal</td>
</tr>
<tr>
<td>PSA</td>
<td>Pressure Swing Absorption</td>
</tr>
<tr>
<td>SAGD</td>
<td>Steam Assisted Gravity Drainage</td>
</tr>
<tr>
<td>SMR</td>
<td>Steam Methane Reforming</td>
</tr>
<tr>
<td>TEC</td>
<td>Techno-Economic Cost</td>
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1. Introduction

Carbon capture and storage (CCS) is a potential mitigation tool for human induced climate change, which enables the consumption of fossil fuels with minimal atmospheric carbon dioxide emissions. The Intergovernmental Panel on Climate Change (IPCC) estimates that 15 – 55% of emission reductions will result from CCS and that the cost of stabilizing CO₂ concentrations is reduced by at least 30% when CCS is included in a mitigation portfolio (IPCC 2005). CCS technology captures CO₂ emissions, typically from large emissions sources, and transports them for sequestration underground, preventing release into the atmosphere. A number of factors are driving the development of CCS in Canada. First, Canada prides itself as an energy superpower, with significant fossil fuel reserves, which include oil, natural gas, coal and oil sands. Canada is the world’s fifth largest energy producer and has the third largest crude oil reserves (CAPP, 2012a). Second, the oil industry has considerable experience injecting CO₂ underground through enhanced oil recovery (EOR). Third, the geography of western Canada is ideally suited for geologic storage of CO₂. Finally, many of Canada’s political leaders have announced climate strategies or goals that depend heavily on CCS deployment since CCS reconciles Canada’s economic and environmental goals.

Policy makers have relatively poor economic information on CCS which, given the importance of CCS may lead to weak climate strategies. Policy makers require information on the economic impact and future emissions trajectories when designing climate strategies or policies. Robust analysis of climate policy is imperative to ensure that environmental, economic and social objectives can be achieved. Economic models that simulate the relationship between energy and the economy are used to provide relevant information for policy-makers. Thus far, modelers typically use static values in their energy-economy models for estimating CCS costs. This practice leaves plenty of room for improvement as the cost of CCS varies by many factors. The implication of incorrectly modeling the costs of CCS is that the model may inaccurately forecast the economic costs or levels of emissions reductions leading to ineffective climate policies.
First, the costs vary by industry. Industries that release emission streams with high concentration of CO₂ or large quantities of emissions from one location (i.e. one flue stack) have lower capture costs.

Second, the costs vary by region; some regions are more ideally suited for sequestration of CO₂ than others. As the geography of Canada changes dramatically, so does the cost of sequestration. Also, certain region’s capture sources are located closer to their storage locations, reducing transport costs.

Third, costs may vary by quantity of CCS deployed in a region. This relationship occurs for two reasons. Less expensive and more favourable sites will likely be implemented first. As deployment of CCS increases, sequestration may be required in less favourable sites. This relationship can be illustrated by a supply cost curve. A supply cost curve illustrates price increases as cumulative sequestration of CO₂ increases, assuming lowest cost options are implemented first. Costs can also change regionally due to the economic relationship between supply and price for enhanced oil recovery. Enhanced oil recovery (EOR) is a sequestration option that can initially provide revenue. The price paid for CO₂ to be used in EOR will decrease as the supply of CO₂ increases (greater quantity captured), reducing the economic advantage of storage through EOR.

Fourth, costs may decrease as global deployment of CCS increases due to the economies-of-scale and the economies-of-learning effect. As CCS projects can have large upfront costs, average cost reductions can occur if the output is larger (economies-of-scale). Since a minimal number of CCS projects exist globally, costs are also expected to decrease due to learning (economies-of-learning).

Finally, costs may vary with government and industry policy due to public education and involvement in the decision making process. These costs can include the risk and uncertainty of the project, largely affected by public opinion of CCS.

In this paper I investigate the potential for large-scale deployment of CCS in Canada. My research helps address the changing costs of CCS to better inform policymakers and the research community. I primarily focus on the first three factors mentioned above, quantifying how CCS costs differ by industry, region and by increasing
cumulative production nationally. The economic costs for all three aspects of CCS—capture, transport and storage—are determined through the development of regional and national cost curves. The cost curves improve the CCS detail in an energy-economy model. The model is then simulated under various policy scenarios to determine adoption rates of CCS and the economic implications of the climate policies.

**Report Outline**

The report is divided into 5 sections. Chapter 2 provides background information on CCS and energy-economy modeling. Chapter 3 describes the methods I use, including the method used for developing supply cost curves, upgrades to the CIMS models, and the policy scenarios. Chapter 4 offers a discussion of the supply cost curve and modeling results. Finally section 5 concludes the report and recommends future research.
2. Background

This section presents the background information on my study. Initially I describe CCS: the capture technology and the most viable industries, information on storage location, and methods for transporting CO₂ from capture location to storage site. I introduce a couple of key cost measures. I discuss in greater detail why CCS is an ideal mitigation tool for climate change in Canada. I provide an overview of key climate policy instruments and policy evaluation criteria. I introduce energy-economy models used to evaluate climate policy and provide a description of the model used in my analysis. Finally, I outline my research objectives and questions.

2.1. Carbon Capture Methods

The objective of carbon capture is to produce a concentrated stream of CO₂ to be transported to a storage site. While there are a limited number of large-scale CCS plants globally, capturing CO₂ from flue gases is not an emerging technology. A number of industries have been separating the gas for decades. Industries such as natural gas processing and ammonia production facilities remove CO₂ in order to meet process or demand needs, but generally do not sequester the CO₂ (IPCC, 2005).

There are three general systems for capturing CO₂: post-combustion, oxy-fuel combustion and pre-combustion.

*Post-combustion capture*

Post combustion systems separate the CO₂ from the flue gases of fossil fuels combusted with air. The prevalent capture method is absorption, where the flue gas is reacted with a chemical solvent such as monoethanol amine (MEA) that binds to CO₂. The solvent is heated to release the pure CO₂ stream and then recycled to repeat the absorption process (Jaccard, 2005). This method has been used for decades for by-
product recovering of CO₂, direct manufacturing of CO₂ from the combustion of fossil fuels and by the food and beverage industry for recovery of CO₂ released from fermentation (Anderson & Newell, 2004).

**Oxy-fuel combustion capture**

An alternative to post-combustion is oxy-fuel combustion capture in which fossil fuels are combusted in the presence of oxygen instead of air (air includes approximately 78% nitrogen and 21% oxygen by volume). Consequently, a much purer stream of CO₂ is produced, greatly decreasing, if not eliminating, the need for expensive CO₂ capture. Additionally, this would reduce nitrous oxide emissions (an acid rain pollutant) and the subsequent need for scrubbing. The disadvantage of this method is that producing pure oxygen is very costly and requires significant amounts of energy (Anderson & Newell, 2004; Jaccard, 2005).

**Pre-combustion capture**

Pre-combustion systems process the primary fuel (consisting of a hydrocarbon chain) in a reactor to separate the hydrogen from the CO₂. The separated hydrogen is used as a fuel. The remaining CO₂ would be sequestered instead of released to the atmosphere (IPCC, 2005). Pre-combustion capture can be easily applied to power plants that use Integrated Gasification Combined Cycle (IGCC) technology. The IGCC process without capture gasifies coal into what is known as synthesis gas (or syngas), a mixture of carbon monoxide and hydrogen, which is combusted in a gas turbine. An IGCC with capture would include an additional step prior to combustion. The syngas would be reacted with steam under a catalyst to produce hydrogen and CO₂. Separating the hydrogen from the CO₂ would leave a pure stream of CO₂ for compression and ultimately storage (Anderson & Newell, 2004).

Capturing CO₂ requires additional energy for the compression and capture systems, known as an energy penalty. While CCS significantly reduces CO₂ emissions, the technology requires more energy to produce similar output levels, reducing the overall efficiency of the source. Capture efficiencies for power plants using commercial CO₂ capture technologies are 85 – 95%. By including the energy-use increase,
commercial CO₂ capture systems can reduce CO₂ emissions of power plants by 80 – 90% per kWh (IPCC, 2005).

2.2. Capture Sources

Not all industries or sources are suitable for carbon capture. As carbon capture has significant capital costs and benefits from economies-of-scale, large, stationary sources of CO₂ are most viable. Many coal-fired and natural gas utilities emit more than 1 Mt of CO₂ annually and are obvious choices for CCS technology. Other industries are also major contenders, such as energy intensive industries like iron & steel manufacturing and cement production or industries that produce high concentration streams of CO₂ such as natural gas processing (Anderson & Newell, 2004).

Fossil Fuel Utilities

The fossil fuel utilities sector is one of the largest point sources of emissions in Canada, emitting 98 Mt of CO₂, or 14% of total Canadian GHG emissions in 2009 (EC, 2011b). Due to the large potential for emissions reductions, fossil fuel utilities are favoured as a primary prospect for CCS by academics and politicians. The majority of academic studies on CCS are focused on applying CCS to fossil fuel utilities, particularly coal-fired utilities (Rootzen, 2010).

Other Industry

While most attention has been focused on applying CCS technology to fossil fuel utilities, if serious emissions reductions are to be met, than CCS will likely be applied to other industries. These other industries can be divided into two classes: industries currently requiring CO₂ separation and energy-intensive industries.

1 Large industrial sources that emit the equivalent of 50 Mt or more of GHGs in CO₂ equivalents are required to report GHG emissions under Environment Canada’s Greenhouse Gas Emissions Reporting Program (GHGRP), which in 2009 covered 250 Mtonnes of emissions (36%).

2 Environment Canada’s 2009 Reported Facility Greenhouse Gas Data is available on line.
A number of industries currently require CO\textsubscript{2} separation for process or demand requirements, such as natural gas processing and those that produce hydrogen. Consequently, the only additional requirements for CO\textsubscript{2} capture would usually be dehydration and compression systems. These industries are typically the lowest cost options for CO\textsubscript{2} capture.

Ammonia manufacturing, petroleum refining and oil sands upgrading all have process requirements for hydrogen. Steam methane reforming (SMR) of natural gas is the most common method of hydrogen production. SMR produces a concentrated stream of CO\textsubscript{2} and thus would be a potential low cost option for carbon capture. If the SMR plant included CCS, the CO\textsubscript{2} recovered would be dehydrated and compressed. Currently, most SMR plants do not include CCS, thus the concentrated CO\textsubscript{2} is vented to the atmosphere (Ordorcia-Garcia, 2007; Keith, 2002, NRCan, 2008).

Natural gas processing is also an ideal candidate for carbon capture because supply requirements necessitate the removal of excess CO\textsubscript{2}. The concentration of CO\textsubscript{2} in the marketable natural gas is required to be less than 2\% by volume. The processing stage where CO\textsubscript{2} and hydrogen sulphide (H\textsubscript{2}S) are removed from the natural gas is known as acid gas removal. A high concentration stream of CO\textsubscript{2} is produced during the acid gas removal stage regardless of whether or not the CO\textsubscript{2} is to be sequestered. Consequently, the cost of capturing CO\textsubscript{2} only includes just the cost of dehydration and initial compression of the CO\textsubscript{2} (Nguyen, 2003).

CCS can provide additional benefits above CO\textsubscript{2} emission reductions if the natural gas to be processed is sour (contains significant concentration of H\textsubscript{2}S). H\textsubscript{2}S is a highly toxic substance that cannot be vented. To manage H\textsubscript{2}S, industry predominantly uses a sulphur recovery plant that recovers elemental sulphur from gaseous hydrogen sulphide (using a method known as the Claus process). The remaining tail gas includes CO\textsubscript{2} and some residual H\textsubscript{2}S, which must be combusted to change the H\textsubscript{2}S into SO\textsubscript{2}. Alternatively, instead of handling H\textsubscript{2}S through the sulphur recovery plant, H\textsubscript{2}S could be sequestered with the CO\textsubscript{2}. If H\textsubscript{2}S is sequestered with the CO\textsubscript{2} there is no need for the sulphur recovery plant and subsequently, no need for incineration of the residual acid gas. Without incineration SO\textsubscript{2} stack emissions are reduced—which is an acid rain air
pollutant—and incineration fuel costs are decreased. Fuel cost savings reduces the net
costs of carbon capture.

The second class of industries favoured for CO$_2$ capture are the energy intensive
industries, which depend on large amounts of process heat and steam generally derived
from fossil fuel combustion. These industries include iron and steel manufacturing,
petrochemicals, petroleum refining, oil sands SAGD (steam-assisted gravity drainage)
operations, and cement and lime production. Similar to fossil fuel utilities, the CO$_2$ can
be captured using post combustion capture methods with chemical absorption
(Anderson & Newell, 2004).

For this paper, I chose to focus on the above-mentioned industries. They
represent 80% of Canada’s large final emitter emissions, 35% of Canada’s total
emissions and are the most likely candidates for CCS. The academic literature describes
these industries as the most suited for carbon capture technologies (Anderson & Newell,
2004). The annual emissions in 2009 for these industries are shown in Table 2-1 below.
Environment Canada’s (2011b) data typically represents the total emissions from a
number of separate emission sources. Different flue gas streams have different
suitability for CCS capture. Capture is assumed to be applied to only the major flue gas
stream described subsequently in section 3.1.

Table 2-1 2009 GHG emissions from key industry

<table>
<thead>
<tr>
<th>Source Category</th>
<th>CO2 emissions [MtCO2/year]</th>
<th>GHG emissions [MtCO2-e/year]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Industrial Total</td>
<td>234</td>
<td>234</td>
</tr>
<tr>
<td>Fossil Fuel Utilities</td>
<td>98.5</td>
<td>99.3</td>
</tr>
<tr>
<td>Iron and Steel Production</td>
<td>11.3</td>
<td>11.4</td>
</tr>
<tr>
<td>Cement Production</td>
<td>9.18</td>
<td>9.18</td>
</tr>
<tr>
<td>Ammonia Production</td>
<td>4.91</td>
<td>5.49</td>
</tr>
<tr>
<td>Petroleum Refining</td>
<td>36.6</td>
<td>36.9</td>
</tr>
<tr>
<td>Petrochemicals</td>
<td>4.74</td>
<td>4.78</td>
</tr>
<tr>
<td>Oil Sands</td>
<td>N/A</td>
<td>44.9$^1$</td>
</tr>
</tbody>
</table>

Note. Adapted from EC, 2011 GHG facility data.
$^1$ Value based on Pembina Institute (2011), NRCan (2012), and EC (2011a)
Post combustion capture systems using chemical absorption could be suitable for all industrial processes discussed in this paper. However, process specific capture technologies could likely decrease the cost of capture (Rootzen, 2010).

2.3. Geologic Storage

Geologic storage (or sequestration) refers to injecting CO$_2$ in suitable deep rock formations. CO$_2$ has been naturally stored in the earth’s upper crust for hundreds of millions of years. The first engineered injection of CO$_2$ into geological formations occurred in the 1970’s in Texas, USA for enhanced oil recovery (EOR) projects. The oil industry continues to use EOR today to increase the recoverability of oil reserves (IPCC, 2005). CO$_2$ can be sequestered in a number of different types of geological media, including enhanced oil recovery, depleted oil and gas reservoirs, deep saline aquifers, enhanced coal bed methane recovery, and salt caverns. There are a number of factors that affect the suitability of a sedimentary basin for CO$_2$ storage. Desirable storage sites have large capacity, ease of subsurface injection, and can retain the injected CO$_2$ (Bachu, 2003).

Enhanced Oil Recovery could be a catalyst for CCS as it could provide an economic opportunity to offset a portion of the costs. EOR is a process that increases the amount of recoverable oil by an additional 5 – 15% of the reservoir’s oil by injecting CO$_2$ into the depleted reservoir. ICO$_2$N (2009) forecasts that Alberta could consume 10 – 20 Mt of CO$_2$ per year for EOR increasing oil production by an additional 1.4 billion barrels. However, EOR will likely only serve as an initial catalyst for CCS because as the market share of CCS increases the supply of CO$_2$ will exceed the EOR demand, and the price for CO$_2$ will likely plummet.

2.4. Cost Measures

To evaluate the economic performance of the CCS technologies, two cost measures must be defined: the life-cycle cost and the cost-avoided.
Life-cycle costs (LCC) (or levelized cost) of an individual technology, k, can be defined as annualized capital costs (up-front costs) divided by annual output, plus the annual unit operating and maintenance, and energy costs.

**Equation 1**

\[
LC_{Ckt} = \left( \frac{CC_{kt} \cdot \frac{r}{1-(1+r)^{-n}}}{O_k} \right) + O_{Mt} + E_{kt}, \text{ where:}
\]

- \( CC_{kt} \) is the capital cost of technology k at time t,
- \( O_k \) is the output of technology k,
- \( O_{Mt} \) is the operating and maintenance cost of technology k at time t per unit of service output,
- \( E_{kt} \) is the energy cost of technology k at time t per unit of service output
- \( r \) is the discount rate,
- \( n \) is the equipment lifespan.

Costs for capturing CO\(_2\) can be calculated as the difference in levelized cost of energy between the plant with and without capture. However, a different cost indicator is commonly used because plants with CCS require more energy to capture the CO\(_2\) due to the energy penalty. This indicator is known as the cost of CO\(_2\) avoided [\$/tonne]. Carbon capture is an energy intensive process; as a result, there is a significant difference between costs of CO\(_2\) removed and CO\(_2\) avoided. The cost of CO\(_2\) avoided is calculated using Equation 2 below (Klemes, et al., 2007).

**Equation 2**

\[
\text{costCO}_2\text{avoided[\$/tonne]} = \frac{\left( \frac{\$}{kWh} \right)_{after} - \left( \frac{\$}{kWh} \right)_{before}}{\left( \frac{t_{CO2}}{kWh} \right)_{before} - \left( \frac{t_{CO2}}{kWh} \right)_{after}}, \text{ where:}
\]

- \( \left( \frac{\$}{kWh} \right)_{after} \) is the levelized cost of technology with CCS,
- \( \left( \frac{\$}{kWh} \right)_{before} \) is the levelized cost of technology without CCS,
- \( \left( \frac{t_{CO2}}{kWh} \right)_{before} \) is the emissions intensity of technology without CCS,
- \( \left( \frac{t_{CO2}}{kWh} \right)_{after} \) is the emissions intensity of technology with CCS.
2.5. Supply Curves

A supply curve illustrates how costs increase as quantity of supply increases. In my study I create CCS cost curves, which illustrate how the unit cost of CCS increases as cumulative sequestration of CO₂ increases. Supply curves are a simplistic tool that provides policy-makers with a sense of the cost of “scaling-up” a specific GHG abatement option, such as CCS, in order to compare against the cost of other options.

Three previous papers estimate cost curves for CCS. Dooley, et al. (2004) estimates a CO₂ supply curve for North America. The emphasis of the paper was on the cost of transportation, injection and additional costs and revenue associated with EOR and enhanced coalbed methane (ECBM). They did not include the cost of capture and compression. The authors defined a set of rules to determine which CO₂ point sources (the location of capture) would be given priority to a storage reservoir. First, the source with the lowest unit transportation and storage cost would get first priority. Since the cost of capture was ignored, the cost depended on proximity between sites and the source’s mass flow rate of CO₂. Second, the reservoir must be able to sequester at least ten years of CO₂ from the point source. Dahowski et al. (2005) developed CO₂ sequestration cost curves for the Midwestern United States. The same methodology as Dooley (2004) was used, except the cost of capture was included.

ICO2N (2009) presented a projected 2020 capture supply curve for Canada. The report assumes transportation costs to be $15/t-CO₂ and excludes the cost of sequestration. While the curve considers how costs vary by industry, it ignores regional variation in transport and storage costs, and ignores the supply and price effects of EOR.

My cost curve builds upon the methodology described in the previous papers. My analysis differs from Dooley (2004) by including capture costs, it differs from ICO2N (2009) by including regionally differentiated transport and storage costs, and differs from Dahowski (2005) as it is for Canada.
2.6. Canadian Context

Carbon capture and storage is an ideal match for Canada. Canada’s economy is highly dependent on fossil fuels, western Canada’s geography is well suited for CO₂ storage, industry has the technical expertise, and politicians on the federal and provincial level have the political will to support CCS.

CCS is the only mitigation option that could allow for rapid escalation of fossil fuel production, especially the oil sands, while reducing greenhouse gas emissions in Canada. Canada’s economy is largely dependent on energy production. Canada is the third largest natural gas producer, sixth largest crude oil producer and fifth largest energy producer in the world. Canada is ranked third globally in crude oil reserves (CAPP, 2012a). The fossil fuel intensive economy is partially to blame for Canada’s high levels of GHG emissions. Canada had the fourth highest per capita emissions in 2008 (UNFCC, 2011). By targeting viable CO₂ sources, CCS technology could reduce 40% of Canada’s forecasted CO₂ emissions in 2050 (NRCan, 2010).

Alberta has the largest provincial industrial emissions, nearly equal to all the other provinces combined (Figure 2-1). The high emissions in Alberta result from electricity generation, oil sands production, natural gas processing, oil refineries and the petrochemical industry. Alberta’s electricity generation is dominated by fossil fuels—45% from coal-fired plants and 40% from natural gas (Government of Alberta, 2012). Oil sands production is expected to triple between 2011 and 2030 from 1.6 to 5.0 million barrels of oil per day (CAPP, 2012). Due to the rapid expansion of the oil sands, the industry has become the single largest contributor to GHG emissions growth in Canada (Pembina Institute, 2011). As a result of these emission intensive industrial sectors Alberta’s climate change action plans have largely focused on the adoption of CCS.
Politicians federally and in fossil fuel-endowed provinces have conveyed a willingness to include CCS in their GHG abatement options. Canada’s Minister of Natural Resources, Joe Oliver, recently announced that “Our government is committed to exploring CCS technology to reduce GHGs in key sectors of the Canadian economy…Canada is in an excellent position to lead the world in the development, implementation and deployment of CCS” (NRCan, 2012a). However, Canadian politicians have made similar statements for at least 15 years and have yet to pursue policies, such as emissions taxes or regulations, that would have resulted in significant CCS adoption by now. Over two decades of failed climate policies in Canada suggest that current political statements of intent should be given the same credibility as past statements in the absence of effective policies (Simpson et al. 2007).

Canadian climate change policies have changed in recent years to guarantee that GHG emission reduction plans do not impede continuous exploitation of the abundant fossil fuel reserves in the western provinces. The federal government has suggested that CCS could be a solution for the conflict between climate and fossil fuels. Alberta has committed to reducing their GHG emissions while ensuring continued economic growth based largely on oil sands expansion. The Alberta Government expects CCS deployment will allow for these seemingly contradictory policy goals. In 2008, the Alberta government committed to reducing 200 Mt of emissions or 50% below projected BAU emissions in 2050. Alberta’s emissions in 2010 were 233 Mt-CO$_2$e (Environment Canada, 2012)—the provinces 2050 targets are 17% below 2010 emissions. Reducing Alberta’s 2050 emissions to less than their 2010 emissions while considerably expanding their most emissions intensive sector, the oil sands, will be an
CCS policies have mostly provided funding for research and development or subsidies for initial industrial CCS projects. Federal and provincial governments have committed $3 billion in funding for CCS over recent years that could potentially lead to several large-scale demonstration projects in Canada (Jaccard and Sharp, 2009). However, one of the largest of these funded projects has recently been cancelled. In April 2012, TransAlta announced the termination of their $778 million federal and Alberta government funded TransAlta Pioneer Project (M.I.T., 2012). Lack of carbon pricing and a market for carbon sales were cited as the reasons the project was not economically feasible (Project Pioneer, 2012). More recently, the federal government announced an intention to regulate electricity generation for the reduction of carbon dioxide emissions from coal-fired generation. If implemented, the regulation would set a performance standard requiring that the emissions intensity of electricity generation not exceed 375 t-CO$_2$/GWh, which is equivalent to the emissions intensity of high-efficiency natural gas generation (Government of Canada, 2011b). Effectively, no new coal power plants could be built without CCS technology under this regulation. However, previous governments—including the current Conservative government—have previously announced similar intentions for climate or energy regulations that were never implemented.

### 2.7. Climate Policy Instruments and Evaluation Criteria

Climate policies can be organized in terms of compulsoriness. The most compulsory policies are command-and-control or regulations, which force a consumer or industry to meet a specific standard or adopt specific technology. Financial Incentives or subsidies are the least compulsory. A subsidy provides a financial incentive to consumers or industries to adopt a technology or action. For example, governments could provide a rebate on electric cars. Subsidies have been largely ineffective at reducing greenhouse gas emissions (Goulder and Perry, 2008). In Canada over the last 20 years, federal climate policies have relied predominately on subsidy and information.
programs. However, emissions have continued to increase, significantly missing federal GHG emission targets (Jaccard, 2005). Consequently, I do not include this policy tool in my analysis.

A carbon price falls in the middle of the compulsory spectrum. A carbon price can be achieved as a carbon tax or a cap-and-trade scheme. A carbon tax applies a price on CO₂ emissions, typically based on the carbon content of fuels. Application of the tax can occur at any point in the life cycle of the fuel. Discussion of carbon tax design tends to focus on covering the entire economy (though some areas may be exempt) at the point of fuel consumption. A cap-and-trade policy is a tradable emissions scheme. Government sets a maximum level of emissions (cap) and then issues tradable permits that allow a certain level of emissions. Cap-and-trade schemes are typically proposed to cover upstream producers such as the electricity sector but can be designed to apply economy-wide (Goulder and Perry, 2008). Carbon pricing policies can be designed to be revenue neutral through recycling the revenue gained from the carbon tax or carbon permits. Likewise, emission permits in a cap-and-trade system can be auctioned, providing government with the same revenues it would earn from a carbon tax, again leaving the government to decide how best to recycle the revenue or retain it for its expenditure objectives.

A number of evaluation criteria have been developed to help policy makers choose among policy options, including: economic efficiency, effectiveness, equity, political acceptability, performance under uncertainty and administrative feasibility (Goulder and Perry, 2008, Jaccard 2005). Economic efficiency strives to minimize the societal cost of a policy. Effectiveness measures how effective the policy is at meeting its goal, which in this example is minimizing greenhouse gas emissions. Equitability determines whether the burden of costs or the benefits are focused on certain groups. Political acceptability assesses the level of stakeholder acceptability. Performance under uncertainty attempts to minimize the risks of excessive or inadequate abatement in the presence of uncertainty. Finally, administrative feasibility assesses the ease of policy implementation. My results have focused on comparing the policies in terms of effectiveness, equity and economic efficiency.
Regulatory policies can be an effective method for ensuring that an environmental target is achieved. Sanctions are enforced if non-compliance occurs. Regulation provides industry with certainty in environmental standards, allowing them to better plan for future emission requirements. Governments are very familiar with creating legislation and regulation. Regulation was the dominant approach to environmental policies in the 1970s, and continues to be common today (Jaccard, 2005). Regulations outperform subsidies but not carbon price in terms of cost-effectiveness.

A carbon price is the most economically efficient policy option because it gives firms flexibility to determine how best to reduce emissions. A carbon price may not result in significant CCS deployment if CCS is not amongst the lowest cost options for emission reductions. The design of a carbon price can significantly impact how it performs, especially in terms of political acceptability or administrative feasibility. The clear disadvantage of a carbon price, especially a carbon tax, is lack of political feasibility. A significant segment of the public typically views a tax as an intrusive and coercive government means to increase revenue. In order to minimize this belief and increase equity, carbon prices can be designed to be revenue neutral. For example, the revenue from a carbon tax can be distributed to consumers or industries or regions those most affected by it as a tax rebate or direct, lump-sum payments. Revenue recycling can reduce the cost burden to participants and is important in light of increasing political pressure to allocate permit revenue to aid industries affected by the regulation. However, revenue recycling may not significantly increase the political feasibility of a tax because those who benefit from revenue recycling are typically less informed and less mobilized than those who oppose the tax like industry lobby groups (Jaccard 2005).

While carbon pricing policies typically have a substantial cost advantage over regulation, the advantage may be moderate if minimal heterogeneity exists among firms. In such situations, a technology mandate can have almost equal marginal abatement costs (the cost for the last additional emissions reduction option) between firms.
2.8. Energy-economy models

Decision-makers require information on the projected outcome of policies in terms of environmental effectiveness, cost-efficiency, and equitability (Nordhaus, 2008). Models that incorporate the linkages between energy, the economy, the environment and trade can be useful tools for economic policy analysis. Models offer decision makers information on how the energy system is projected to transform over time with and without policy intervention. The two main classifications of economic models for analyzing energy policies are “top-down” and “bottom-up”. A bottom-up model is technologically explicit whereas a top-down model considers consumer preferences and macro-economic feedbacks (Murphy et al., 2007).

**Bottom-up Models**

A bottom-up model (the engineer’s model) uses attributes of various current and prospective technologies to predict future energy demands and consequently environmental effect. Changes in energy efficiency, fuels, emission control equipment and infrastructure may affect energy demand (Jaccard, 2003). Bottom-up models are technologically explicit, which is a measure that indicates how extensive the individual energy intensive technologies in an energy system are represented in the model. A bottom-up model optimizes costs in a specific sector, but usually ignores linkages between other sectors and the rest of the economy. A disadvantage of a bottom-up model is that it does not take into account households’ and firms’ values and perceived costs of various technologies (i.e. intangible costs—new technologies are more risky, have longer payback periods, or may not be perfect substitutes). Furthermore, as it ignores relationships with the rest of the economy, a bottom-up model can miss feedbacks between demand and supply of energy for example. By overlooking additional costs and feedbacks, a bottom-up model may prescribe inadequate policies and technologies (Murphy et al., 2007).

**Top-down Models**

In comparison, a top-down model estimates at the aggregate level the relationship (the production function) between inputs (the factors of production) and output, all measured in monetary terms. Unlike a bottom-up model, a top-down model is
technologically implicit (Jaccard, 2003). In order to capture technological change in a top-down model, two parameters, the long-run elasticity of substitution (ESUBs) and the Autonomous Energy Efficiency Index (AEEI) dictate the rate of change in the energy efficiency of capital stock. ESUBs measure how easily different factors, such as fossil fuels and electricity, can be substituted for each other (Hicks, 1932). The AEEI is the rate of change in energy efficiency over time due to technological change that is independent of energy price. Both of the parameters are generally estimated based on either observed behaviour or adjusted by the modeler if future situations are expected to differ from historical trends. Higher ESUB values result in lower costs for policies that target energy use or GHG emission reductions. A high AEEI value represents an economy that is quickly becoming more energy efficient (Bataille et al., 2006).

The strengths of top-down models are that they are behaviourally realistic and include macroeconomic feedbacks. Behavioural realism refers to how effective the model is at characterizing the choices made by individuals and firms during investments in energy utilizing technologies or infrastructure. Macroeconomic feedbacks represent how sensitive the model is to a change in production in one sector of the economy resulting from a change in another sector (Murphy et al., 2007). The downside of top-down models is that they are unable to demonstrate how future trends differ from past because new technology regulations and changing expectations affect long-run market incentives (Loschel, 2002). As CCS is a new technology, top-down models have difficulty forecasting the impact of CCS deployment, and are thus not an appropriate tool for my analysis.

**Hybrid Models**

Limitations from the bottom-up and top-down models have motivated many researchers to explore hybrid modeling. Hybrid models combine the technological explicitness of a bottom-up model, and the microeconomic realism and macroeconomic completeness of a top-down model. By including equilibrium feedbacks in a hybrid model, it is able to capture the reallocation of productive resources due to changes in demand (structural change) created by policy (Murphy et al., 2007).
The model I use in my policy analysis is known as CIMS. CIMS is a hybrid energy-economy model, initially developed by researchers at the Energy and Materials Research Group at Simon Fraser University as a model based on the Canadian economy. CIMS endogenously models the technological evolution of the Canadian energy system to 2050 (at 5-year intervals). The model can be simulated both in the absence of policy (business-as-usual, BAU) and in the presence of a specific policy (for example a carbon price or a technology regulation). Behavioural realism is included in the model through empirically estimated behavioural parameters.

CIMS-Canada is disaggregated into seven different regions (the provinces, with the Atlantic Provinces compiled as one region) and twenty different sectors (various industries, electricity, residential, commercial, waste and transportation). Nine of the 20 sectors include technologies with an option for carbon capture.

**Table 2-2  Sectors with Carbon Capture**

<table>
<thead>
<tr>
<th>Category</th>
<th>Processes and Services</th>
</tr>
</thead>
<tbody>
<tr>
<td>Biodiesel</td>
<td>Steam</td>
</tr>
<tr>
<td>Chemical Products</td>
<td>Ammonia Synthesis, Steam</td>
</tr>
<tr>
<td>Electricity</td>
<td>Conventional electricity generation</td>
</tr>
<tr>
<td>Ethanol</td>
<td>Steam</td>
</tr>
<tr>
<td>Industrial Minerals</td>
<td>Cement—Clinker, Lime—Lime Kilns, Heat</td>
</tr>
<tr>
<td>Iron and Steel</td>
<td>Steam, Integrated Steel</td>
</tr>
<tr>
<td>Natural Gas Extraction</td>
<td>Formation CO2, Heat</td>
</tr>
<tr>
<td>Petroleum Crude</td>
<td>Hydrogen, Steam</td>
</tr>
<tr>
<td>Petroleum Refining</td>
<td>Hydrogen, Steam, Refining-Cracking</td>
</tr>
</tbody>
</table>

**Capture Costs**

The current version of CIMS includes industry-specific carbon capture cost. The costs are based on reports by the *Clean Coal Power Coalition Phase (CCPC) II Summary Report*, (2008) and the IPCC (2005). The CCPC is an industry association of North American electricity producers. Their report provides cost estimates for coal-fired generation. To obtain cost estimates for the other industries, the values in the IPCC
report were prorated—the costs for coal generation were compared between the IPCC and CCPC to determine the ratio between the two costs. Industry typically estimates higher CCS costs than independent academic researchers. The IPCC values for the other industries were multiplied by the ratio difference for coal generation. For example, if the costs for coal generation presented by the CCPC were twice as large as the IPCC, all other IPCC costs were multiplied by two. As carbon capture technology has low global cumulative production, the costs are expected to decreases as a result of learning. This relationship is modeled using a declining cost function with a learning rate.

**Transport and Storage Costs**

Costs for transport and storage are not included in CIMS. Since these costs are not included, two important cost influencing factors are also not included. First, as transport and storage costs are dependent on the region, CIMS includes no regional variation of CCS costs. Second, the relationship between increasing transport and storage costs as a result of increased regional CO₂ sequestration is also not included. In order to better reflect the cost of CCS, one of my objectives in this research is to include these costs in the model.

**Learning Rates**

Technology cost in CIMS can also vary by economies-of-learning. Decreases in a technology’s cost as a result of gains in experience by producers are known as learning-by-doing. CIMS models technological learning by a declining capital cost function (Equation 3)

**Equation 3**

\[ CC_t = \left( \frac{CP_t}{CP_0} \right)^{\log_2(PR)} \]

where:

- \( CC_t \) is capital cost of technology in time \( t \).
- \( CP_t \) is cumulative production of technology at time \( t \).
- \( CP_0 \) is initial cumulative production of technology.
- \( PR \) is the progress ratio, equal to \( 1 - \text{learning rate} \).
In order to better reflect the change in carbon capture technologies due to learning-by-doing, one of my objectives in this research is to update these values in the model.

2.9. Research Objectives and Questions

The objectives and questions for this research project are a response to limitations in current CCS policy analysis.

Research objectives:

• To determine how CCS costs vary by region and by increases in national cumulative sequestration,
• To develop regional and national CCS supply cost curves,
• To use a model to analyze potential climate change policies, especially those that focus on the deployment of CCS in Canada.

Research questions:

1. How do the costs of CCS differ in Canada regionally?
2. How do the costs of CCS increase as cumulative sequestration of CCS increases?
3. What are the potential economic and environmental impacts of various climate change policies in Canada, regionally and sectorally?
4. What levels of CCS deployment can be expected under various climate change policies in Canada?
5. What is the economic impact of applying CCS regulation policies that only target specific sectors versus a carbon price?
3. Methodology

Section 3 presents the methodology used for my paper. First, I estimated the quantity of CO₂ emissions captured and the unit cost of capture by industry. Second, I determined the transport and storage costs by region and discussed the impact of enhanced oil recovery on storage costs. Third, I compiled the capture, transport and storage costs to create a CCS cost curve for Canada. Finally, I integrated the economic information from the cost curves in an energy-economy model in order to simulate the economic and environmental impact of five climate policies.

3.1. Capture

To assess the economics associated with carbon capture, I determined the quantity of emissions captured and the unit cost of capture by industry. I obtained the quantity of emissions from the key processes for carbon capture technology as well as the unit cost of capture for those processes. I performed a literature review to determine a range for unit costs by industry and then used an average value for generating the cost curve. I assumed a capture efficiency of 90%. While I ignored the increased energy requirements (and thus increased emissions) due to the CCS energy penalty, by using the cost-avoided value I incorporated the price increase from the additional energy use.

I used Environment Canada’s (EC) 2009 Reported Facility Greenhouse Gas Data² from the Greenhouse Gas Emissions Reporting Program (GHGRP) to determine

² Environment Canada’s 2009 Reported Facility Greenhouse Gas Data is available on line http://www.ec.gc.ca/pdb/ghg/onlinedata/dataSearch_e.cfm
the most viable capture sites. EC’s data includes geographic location, industry type (delineated by NAICS code), and annual CO₂ emissions. The industries targeted were:

- Fossil fuel utilities greater than 300 MW (NAICS 221112)
- Iron and steel manufacturing (331110)
- Cement manufacturing (327310)
- Lime manufacturing (327410)
- Ammonia manufacturing (325313)³
- Hydrogen plants (industrial gas production) (325120)⁴
- Petroleum refineries (324110)
- Petrochemical manufacturing (325110)
- Oil sands (nonconventional oil extraction) (211114)⁵
- Natural gas processing plants (211113)⁶.

I performed a literature review to determine the cost of capture for each industry and used an average cost-avoided value. Appendix A contains a summary of the literature review. Costing data in this report is shown in 2005 CDN$.

Most literature reviewed only provided costing values for new plants (some cases described them as First-Of-A-Kind and Nth-Of-A-Kind plants) that would be designed and built with the equipment necessary for capture. The cost for retrofitting existing plants for carbon capture is expected to be higher than for newly built plants because the facility space has not been optimally sized for the necessary equipment. Only coal-fired fossil fuel utilities had adequate literature on costs for retrofitting existing plants. To overcome the lack of costing data on retrofits, I applied a costing factor. A National Energy Modeling System (NEMS) (2009) study used a costing factor of 1.25, but with little explanatory discussion. Based on the literature, retrofitting coal utilities for carbon

³ Only includes chemical fertilizer manufacturers that manufacture ammonia
⁴ Details on hydrogen plants included described below
⁵ Details on nonconventional oil extraction sites described below
⁶ Only includes the Fort Nelson Gas Plants, explanation provided below
capture was on average only 15% more expensive than carbon capture for new plants. Consequently, I always assumed a cost factor of 1.2, in between the value chosen by NEMS and the average value found in the literature review.

3.1.1. **Fossil Fuel Utilities**

The majority of fossil fuel utilities in Canada use either pulverized coal (PC) technology or natural gas combined cycle (NGCC); thus I ignored integrated gasification combined cycle (IGCC) technologies for the generation of a cost curve. The predominant proposed capture method is post combustion capture through absorption using a chemical solvent such as MEA (Anderson & Newell, 2004).

**Natural Gas**

Cost for capturing CO$_2$ focused on applying post-combustion technology to natural gas combined cycle (NGCC) facilities. Estimates ranged from $45/t$-CO$_2$ to $125/t$-CO$_2$. I used an average value of $99/t$-CO$_2$ avoided.

**Coal**

The cost of CO$_2$ avoided is expected to decrease as plant size increases as a result of economies of scale. Klemes et al. (2007) estimate the cost relationship between cost of CO$_2$ avoided versus plant size using a quadratic equation for plant capacity in the range of 300 MW to 2,000 MW. Cost estimates are based on new coal-based utilities. The authors did not state the assumed base year for costs. For a 90% capture efficiency the equation is:

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7 Sources: IPCC, 2005; Global CCS Institute, 2011; Rubin et al., 2007; Davison 2006; David & Herzog, 2000; Hamilton et al. 2008; Paltsev et al., 2005; NETL, 2006; EPRI 2006; SFA 2006; IEA 2011.
Equation 4
\[
\text{cost}_{CO_2\text{avoided}}[\$/\text{tonne}] = 0.1098 \left( \frac{PC}{100} - 2 \right)^2 - 3.4086 \left( \frac{PC}{100} - 2 \right) + 56.533
\]

where: \( PC \) = plant capacity [MW].

As shown in Figure 3-1, the cost relationship estimated by Klemes is within the range of values found from the literature review. The reviewed literature found that the average cost of CO\(_2\) avoided was $62/t-CO\(_2\) and the average plant size with capture was 535 MW (580 MW without capture). Ten of the fifteen coal utilities included in the analysis have a capacity between 600 and 3000 MW. For analysis I used Klemes’s relationship to incorporate decreasing costs for larger capacity coal utilities. As Klemes’s relationship is for new plants, I multiplied these values by the same retrofit cost factor.

**Figure 3-1 Capture Cost for Coal Utilities for Plant Capacity**

3.1.2. **Industries requiring CO\(_2\) separation**

**Industries requiring Hydrogen Production**

A number of industries produce hydrogen for process requirements: ammonia manufacturing, petroleum refining, and oil sands upgrading. There are also a few industrial gas plants in Canada that produce hydrogen. Hydrogen production by SMR produces a high purity CO\(_2\) stream (Keith 2002). I used two different methods to estimate the quantity of CO\(_2\) most-suited for capture. Under the first method, I used an estimate of the percentage of CCS viable process emissions out of the total emissions.
from the plant. Alternatively, if a percentage estimate was not available, I estimated CO₂ emissions to be captured by multiplying an emissions intensity of hydrogen production by annual production. For example, I multiply the emissions intensity of hydrogen production in ammonia manufacturing (t-CO₂/t-NH₃) by annual production of ammonia (t-NH₃/year) to obtain emissions of CO₂ from hydrogen production in the ammonia industry (t-CO₂/year).

**Ammonia Manufacturing – Hydrogen**

Process emissions from hydrogen production are the most economically viable source for CO₂ capture in ammonia manufacturing (Anderson and Newell, 2004). As literature sources did not contain estimates of the percentage of hydrogen process CO₂ emissions from total ammonia manufacturing emissions, I used the alternative estimation method. I estimated the CO₂ process emissions by multiplying the process emissions intensity by site-specific annual ammonia production levels. Average emission intensity of hydrogen production is 1.56 t-CO₂/t-NH₃ (Environment Canada 2010; IPCC 1996). The most recent site-specific ammonia production publically available is an average over 2000 to 2002 (NRCan, 2008). To obtain the value I pro-rated the averaged 2000 to 2002 values by comparing total ammonia production over that period with 2009. The values estimated based on this method are higher than those under Environment Canada’s GHG reporting. This difference could be attributed two factors: site specific changes in production levels differ from regional trends in ammonia production and many ammonia producers in Canada already capture part or all of the process-generated CO₂ to use in production of urea (NRCan, 2008). Refer to Appendix B for a detailed table of ammonia emissions estimation.

Cost estimates of carbon capture for ammonia manufacturing range from 12 to 24 $/t-CO₂ avoided (Global CCS Institute, 2011; Anderson & Newell, 2004). An average of the values multiplied by the retrofit cost factor results in a capture cost estimate of $21/t-CO₂ avoided.

**Petroleum Refining – Non-combustion emissions**

About 22% of emissions from petroleum refining are from non-combustion use of fossil fuel through the production of hydrogen or from gasification of petroleum residues
and waste productions. The cost of capturing emissions from residue gasification is estimated to be $19\text{t-CO}_2$ avoided (Anderson and Newell, 2004). I assumed that 22% of emissions could be captured (via retrofit) for a cost of $22/\text{t-CO}_2$ avoided.

**Oil Sands – Upgrading with Hydrogen**

Oil sands production upgrades the bitumen into synthetic crude oil using hydrogen. As literature sources did not contain estimates of the percentage of hydrogen process CO\(_2\) emissions from total ammonia manufacturing emissions, I used the alternative estimation method. Ordorcia-Garcia (2007) determined (Appendix C) the hourly GHG emissions by process for three major oil producers in Alberta: Syncrude (Mildred and Aurora site), Suncor, and Shell-Albian.\(^8\) These three producers produce 93% of the synthetic crude processed in Alberta (ERCB, 2010a and ERCB, 2010b).

To determine the annual emissions, I divided the hourly GHG emissions from hydrogen by the annual production used by Ordorcia-Garcia and then multiplied by the annual production in 2009. The total annual GHG emissions associated with hydrogen production for the three producers is 8 Mt (refer to Appendix C).

I assumed all hydrogen is produced on site. Cost estimates for retrofitting hydrogen production plants associated with bitumen upgrading range from $6.9/\text{t-CO}_2$ to $34/\text{t-CO}_2$ depending on type of plant. Older plants without pressure swing absorption (PSA) technology are less expensive than newer plants with PSA (Keith, 2002). An average value of $29/\text{t-CO}_2$ is assumed.

**Hydrogen Production**

There are three facilities, delineated by NAICS code 325120—Industrial Gas manufacturing, that manufacture hydrogen gas for petroleum refineries or other

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\(^8\) The Ordocia-Garcia (2007) paper identifies the three producers as A1, A2 and A3. However, based on the working paper by O-G available at <http://www.engineering.uwaterloo.ca/twiki/pub/Main/PeterDouglas/GHGT8PaperGOG-final.pdf> the specific producer can be determined by comparing the values provided in both papers.
industries with process requirements for hydrogen. As the pure stream of CO$_2$ is produced at the source of hydrogen production, capture technology and transportation pipelines would be applied to the hydrogen manufacturer. Information on the quantity of hydrogen sold to which facilities is generally not publically available. In those circumstances, to avoid double counting the CO$_2$ emissions, the emissions from the hydrogen plant are ignored. The facilities purchasing hydrogen are expected to be located in close proximity to the hydrogen plant, thus differences in transport costs are negligible.

The Corunna Hydrogen Facility (owned by Air Products Ltd.) produces 80 million standard cubic feet (1x10$^{12}$ m$^3$/year) of hydrogen using SMR for the Shell refinery and the Suncor Energy Products complex in Sarnia (Sarnia-Lambton Economic Partnership, 2011). The plant uses PSA (pressure swing absorption) technology, and thus is in the higher range for retrofit cost estimates (ranging from $20 to $34/t-CO$_2$). An average value of $33/t-CO$_2$ is assumed. As the Shell refinery and the Suncor complex do not produce hydrogen on site, non-combustion emissions for those sites were not included.

The Shell Scotford Complex located northeast of Fort Saskatchewan, AB includes an upgrader, a refinery, a chemical plant, and a hydrogen generation plant (owned by Air Liquide). To avoid double counting emissions, the emissions from the hydrogen generation plant were ignored. As four facilities are located in the same area this has a negligible effect on transport cost.

The Edmonton Hydrogen Facility, owned by Air Products Ltd., sells hydrogen to a number of industries near Edmonton, including the Suncor Refinery. To avoid double counting emissions, the emissions from the hydrogen plant were ignored. As the facilities purchasing the hydrogen are located in the same area this has a negligible effect on transport cost.

**Natural Gas Production**

Information on the amount of CO$_2$ vented from acid gas or the amount of marketable natural gas produced was not available on an individual plant basis. Consequently, I used an alternative method than what was used for other industries.
Alberta produces 76% and British Columbia produces 18% of Canada’s natural gas (National Energy Board, 2009). I did not include Alberta natural gas production in the CCS cost curves. First, Alberta has hundreds of small natural gas processing plants. Small plants are less economically viable to retrofit with CCS technology. Second, natural gas production is expected to decrease in Alberta, and it is unlikely that new technology (CCS) would be constructed for a diminishing industry. Third, the natural gas produced in Alberta is predominantly conventional natural gas with low concentrations of formation CO₂. As a result, the CO₂ removed per m³ of natural gas is lower than certain reserves in British Columbia (personal correspondence, Tubbs, January 17, 2012).

BC production of shale gas and tight gas in the Montney and Horn River area is expected to increase. In their mid-range scenario, NEB (2011) forecasts that Horn River production will more than double between 2010 and 2013 (6.9 m³ 10⁶/d to 16.1 m³ 10⁶/d). The concentration of formation CO₂ in Horn River is 12% by volume, significantly higher than Montney (NEB, 2007). I assumed carbon capture in the natural gas industry would only be applied to high formation CO₂ reserves such as Horn River.

Currently, one natural gas plant in Fort Nelson operated by Spectra Energy produces from the Horn River reserve. A CCS project has been proposed for this plant. Approximately 70% of the CO₂ emissions are formation CO₂ (CO₂ that is naturally found in the raw gas); the remainder are due to combustion (Spectra Energy, n.d.). Formation CO₂ is removed during acid gas removal, producing a higher CO₂ concentration in the flue gas. For the CCS cost curves, I only included this plant. To estimate captured CO₂ emissions, I multiplied the annual CO₂ emissions by percentage of emissions from formation (70%) and the capture efficiency (90%):

\[
\text{Captured CO}_2 = \text{CO}_2 \text{ annually} \times \% \text{ formation emissions} \times \text{capture efficiency}.
\]

Natural gas processing produces a high concentration stream of CO₂. I assumed the cost of CO₂ capture for natural gas processing to be equal to the cost of capture from hydrogen production because both processes only require dehydration and compression.
3.1.3. Energy Intensive Industries

Iron & Steel Manufacturing

The iron and steel industry is highly energy intensive, and consequently the production of steel tends to have significant associated CO₂ emissions. The largest source of CO₂ emissions in a conventional integrated steel mill is from the blast furnace. Cost estimates for capturing CO₂ emissions from the flue gas of the blast furnace range from $30/t-\text{CO}_2$ to $59/t-\text{CO}_2$ avoided (Global CCS Institute, 2011; Anderson & Newell, 2004; Rootzen et al. 2010). I assumed an average value of $60/t-\text{CO}_2$ avoided for retrofit. Approximately 70 - 80% of the CO₂ emissions are contained in the flue gas of the blast furnace (Anderson & Newell, 2004; Rootzen et al. 2010). I assumed 75% of CO₂ emissions from iron and steel production are captured.

Cement & Lime Manufacturing

The most energy and emissions intensive step in cement manufacturing occurs during calcination, when limestone is decomposed into lime. This reaction occurs in the precalciner and in the rotary kiln during clinker production. Chemical decomposition in the precalciner produces 60 – 65% of total emissions. The remainder of emissions result from fuel combustion, with 65% of combustion emissions occurring in the precalciner (IEA, 2009). As the lime industry uses similar processes to the cement industry, I assumed the capture costs and capture efficiencies to be the same.

Two options exist for capturing CO₂ in the cement and lime industry. Oxy-combustion capture in the precalciner would capture approximately 50% of emissions and cost $67/t-\text{CO}_2$ to retrofit. Post-combustion capture would capture about 80% of CO₂ emissions, but cost approximately double (Rootzen et al. 2010). I assumed that the lower cost, oxy-combustion option would be implemented.

Petrochemical Manufacturing

Combustion of fossil fuels contributes to 77% of petrochemical manufacturing emissions. The cost of capturing was estimated to be $82/t-\text{CO}_2$ avoided for retrofits. A capture efficiency of 90% was assumed (Anderson & Newell, 2004).
**Oil Sands – SAGD**

Oil producers use steam assisted gravity drainage (SAGD) as an enhanced oil recovery technique. SAGD consists of two horizontally drilled wells a few meters apart. The upper well is filled with steam and the lower well with crude oil or bitumen. The steam from the upper well heats the crude oil, reducing the viscosity of the crude oil, which is then pumped out. SAGD is the second largest source of emissions in the oil sands, after upgrading and is forecasted to exceed upgrading as the largest source of CO$_2$ emissions after 2016 (Ordorcia Garcia, 2011).

SAGD currently produces approximately 20% of the oil sands CO$_2$ emissions. Both steam and power produce low purity flue gas CO$_2$ concentrations (3.5 and 9.2% for steam and power respectively). As Ordorica-Garcia (2011) estimates capture costs as a function of oil sands flue gas stream concentration, not by process, I assumed as a conservative estimate that 100% of the SAGD emissions have a flue gas concentration of 3.5%. Capture cost increases as flue gas concentration decreases. The capture cost of steam used in the oil sands is $227/tonne of CO$_2$.

**Petroleum Refining - Combustion**

Combusting fuel for heat accounts for approximately 30 – 60% of onsite emissions from petroleum refining. I assumed an average value of 45%. As the concentration of CO$_2$ in the heater flue gas is typically lower than from a pulverized coal utility (9% versus 13% CO$_2$ by volume), the cost of capture is higher for petroleum refineries than coal utilities. Ho (2011) estimates the cost of capturing CO$_2$ from heater flue gas to be $96/t-CO$_2$ avoided.

A summary of capture costs (new and retrofit) and percentage of total emissions viable for CO$_2$ capture by industry is shown in Table 3-1 below.
Table 3-1  Summary of Capture Cost by Industry

<table>
<thead>
<tr>
<th>Industry</th>
<th>Capture Cost New Range ($/t-CO₂ avoided)¹</th>
<th>Retrofit Capture Cost² ($/t-CO₂ avoided)¹</th>
<th>Capture Emissions (% of total emissions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ammonia</td>
<td>12 - 24</td>
<td>21</td>
<td>N/A³</td>
</tr>
<tr>
<td>Iron and Steel</td>
<td>30 - 59</td>
<td>60</td>
<td>70%</td>
</tr>
<tr>
<td>Cement (and Lime)</td>
<td>52 - 91</td>
<td>67</td>
<td>50%</td>
</tr>
<tr>
<td>Petrochemical Manufacturing</td>
<td>68</td>
<td>82</td>
<td>77%</td>
</tr>
<tr>
<td>Petroleum Refineries – non-combustion</td>
<td>19</td>
<td>22</td>
<td>22%</td>
</tr>
<tr>
<td>Petroleum Refineries – combustion</td>
<td>96</td>
<td>115</td>
<td>45%</td>
</tr>
<tr>
<td>Hydrogen Production</td>
<td>7 – 68⁴</td>
<td>29</td>
<td>N/A⁵</td>
</tr>
<tr>
<td>Fossil Fuel Utilities – Coal</td>
<td>34 - 95⁶</td>
<td>67⁶</td>
<td>90%</td>
</tr>
<tr>
<td>Fossil Fuel Utilities – Nat Gas</td>
<td>45 - 125</td>
<td>99</td>
<td>90%</td>
</tr>
<tr>
<td>Oil Sands – SAGD⁷</td>
<td>189</td>
<td>227</td>
<td>20%⁸</td>
</tr>
</tbody>
</table>

Note. ¹Costs are given in 2005 CDN
²An average of the new capture costs from the literature review is multiplied by the retrofit factor of 1.2 to obtain the retrofit capture cost. A summary of the values from the literature review can be found in Appendix A.
³Emissions captured for Ammonia are estimated based on annual ammonia produced multiplied by an emissions intensity of 1.56 t-CO₂/t-NH₃ (EC, 2010).
⁴Keith (2002) estimates the cost of modifying the design of new hydrogen plants to incorporate CO₂ capture would cost between $18 and $33/t-CO₂.
⁵Percentage captured depends on the industry using hydrogen production. If a hydrogen production plant this value equals 71%.
⁶Cost for Coal utilities are dependent on the capacity of the utility. A quadratic equation is used based on a Klemes (2007) paper. The value 67 is an average of the values used, multiplied by the retrofit factor.
⁷Focused on only 4 oil sands sites: Shell Albian, Horizon Oil, Suncor Energy, Mildred and Aurora (Syncrude). Most values are from works published by Ordorica-Garcia.
⁸~20% of total oil sand site emissions are from SAGD operations.

3.2. Transport and Storage

Following capture, CO₂ must be transported to an adequate storage location. First, I obtained the locations of the most suitable geographic storage sites based on Bachu (2003). Second, I matched capture sites (industries emitting CO₂ as discussed in section 3.1) to storage sites based on a set of priority rules discussed below. By
matching capture sites with storage basins, a regionally specific estimate of storage cost could be obtained. Finally, I calculated the distance between the capture site and the storage site to determine an estimate for transport cost. I have chosen to only include storage options within Canada.

The types of geologic storage media included in the analysis are saline aquifers, enhanced oil recovery reservoirs, and depleted oil and gas reservoirs. Storage potential varies significantly by geographic region. Saline aquifers present the largest capacity for storage in Canada. Figure 3-2 below illustrates the sedimentary basins located in Canada as delineated by Bachu (2003).

**Figure 3-2  Distribution of Sedimentary Basins**

![Sedimentary Basins Map](image)

*Note.* Obtained from Bachu (2003).

**Western Canada**

The Alberta and Williston basin, covering most of Alberta and southern Saskatchewan, were ranked as highly suitable storage basins (refer to Figure 3-3). The southwestern, southern, and northwestern regions within these basins were ranked as either suitable or highly suitable for CO₂ sequestration. For the analysis, storage
locations were approximated as within those three regions. Rubin et al. (2008) and Nygaard & Lavoie (2009) provide cost estimates for CO₂ storage in saline aquifers located in the western sedimentary basin, ranging from 0.66 to 3.43 $/tonne. I assumed an average value from the two studies of $1.91/tonne.

*Figure 3-3  Suitability of the Western Canadian Sedimentary Basin for CO₂ sequestration in geologic media*

![Figure 3-3](image)

*Note. Obtained from Bachu and Stewart (2002).*

A large number of depleted oil and gas reservoirs are located in Alberta, Saskatchewan and Manitoba, but I excluded them from the analysis for a couple of reasons. First, the storage capacity of saline aquifers in that region is very large, whereas the majority of depleted oil and gas reservoirs have a capacity less than 3 Mt of CO₂—insufficient for long-term storage of emissions from the majority of capture sources. Second, estimates of costs for saline aquifers versus depleted oil and gas reservoirs where relatively equal. IPCC (2005) estimates the cost of storage in depleted oil and gas reservoirs in the US to be on average $1.6/t and $2.9/t, respectively (range of 0.61 – 4.8 $/t and 0.61 – 15 $/t respectively). Depleted oil and gas reservoirs in that
region provided no clear advantage over saline aquifers. Furthermore, geologic storage in saline aquifers tends to be favoured by industry over depleted oil and gas reservoirs. Many of the oil and gas reservoirs have old and likely lower quality constructed wells, consequently the likelihood of leaks is perceived to be higher.

**EOR in Western Canada**

Enhanced oil recovery provides an economic opportunity for capturing CO$_2$. Bachu (2007) estimates the practical storage capacity for EOR suitable sites in western Canada with individual capacities greater than 1 Mt-CO$_2$ to be 450 Mt-CO$_2$. Capacity and location of EOR sites was obtained from Bachu (2004).

A wide range of economic cost (benefit) estimates exist for sequestering CO$_2$ in enhanced oil recovery sites, ranging from roughly -$10$/t-CO$_2$ to -$85$/t-CO$_2$. The negative sign represents an economic gain from sequestering in EOR sites. On the low end of estimates are papers by Stevens *et al.* (2001) and Rubin, Chen & Rao (2007). Stevens *et al.* (2001) estimate the value of EOR to be -$17$/t-CO$_2$. This paper is more than ten years old and was based on lower estimates for cost of oil per barrel. The value for EOR is highly dependent on the cost of oil. If the price of oil is low, EOR will be less economical. A more recent paper by Rubin *et al.* (2007) also used a value of -$17$/t-CO$_2$, but provided no rationale or reference for why this value is chosen.

A 2007 ICO2N report (Integrated CO$_2$ Network, an industry alliance group) estimated the relationship between supply of CO$_2$ for EOR and the CO$_2$ market price (Figure 3-4). For an annual sequestration rate of approximately 5 Mt, the price per tonne of CO$_2$ is estimated to be $50$/t (no base cost year provided, assume 2005).
A McCoy & Rubin (2009) paper used four case studies to determine the effect of oil price on EOR economics. They found that if oil prices were greater than $75/bbl. three of the 4 case studies were able to break even paying CO$_2$ prices of $70$/tonne.

For my analysis I assumed EOR values based on the ICO2N report, which is in line with the McCoy and Rubin paper. While the ICO2N report is produced by industry representatives and is not in an academic journal, the report takes into account supply and demand economics. As the supply of CO$_2$ for EOR increases, the CO$_2$ market price will likely decrease. Finally, the values from the ICO2N paper are within the range of the McCoy & Rubin 2009 paper.

**Eastern Canada**

According to Bachu (2003) the sedimentary basins located in southwestern Ontario and off the coast of Atlantic Canada obtain a mediocre score in terms of suitability for CO$_2$ sequestration. Accordingly, the cost estimates for storage in those regions are higher than for storage in western Canada. Shafeen (2004) estimates the cost of transport and storage for a coal utility plant located in southwestern Ontario as $9.7/\text{t-CO}_2$. Based on the assumption for transport costs outlined in the study, I estimated the cost of only storage to be $6.3/\text{t-CO}_2$. 

*Note.* Obtained from ICO2N, 2007.
There are two potential storage locations in Ontario (refer to Figure 3-5 below). The capacities of the northern zone and the southern zone are conservatively estimated as 289 Mt and 442 Mt, respectively. While onshore pipeline and storage is significantly cheaper than offshore, a large number of towns are located along the shores of the Great Lakes, especially Lake Erie. Consequently, obtaining the right-of-way to transport and store CO₂ would likely be difficult. All storage is assumed to be stored 50 km offshore based on assumptions used in Shafeen et al. (2004). Capture sources are more densely located in southern Ontario, thus the cost of offshore pipeline could be lower due to economies-of-scale from a pipeline network. Estimates of this decrease are not included in the analysis.

**Figure 3-5  Saline Aquifers in Southern Ontario**

![Map of Saline Aquifers in Southern Ontario](image)

*Note.* Obtained from Shafeen et al., 2004, Figure 1.

Significant geological storage potential exists in the United States adjacent to Ontario. While Michigan has the largest potential for storage in deep saline aquifers, other neighbouring states such as Ohio, Pennsylvania and New York also have significant capacity. Oil and gas reservoirs are also present and studies have suggested that there is large potential for enhanced oil/gas recovery coupled with CO₂ storage in that region (NETL, 2010). While transport distances would generally be longer, storage
costs would likely be lower if onshore. Consequently, differences in transport and storage costs for the two options would likely be minimal. Storage in the United States could significantly increase the storage capacity available to Ontario, but this option may be more politically difficult because it would require cross border trade and transport agreements. For this paper I ignored the United States options.

Geographic storage in Atlantic Canada is assumed to occur in the offshore Atlantic Basin (refer to Figure 3-2). No geographically specific cost estimates are available. While both southwestern Ontario and Atlantic basin are located offshore, to be conservative, I assumed a cost twice that of southwestern Ontario for the Atlantic Basin ($12.5/tonne).

Storage options in British Columbia are largely limited to the northeastern part of the province. A sedimentary basin is located off the coast of British Columbia (Figure 3-2); however the basin was ranked with very low suitability for carbon dioxide storage (Bachu, 2003). No adequate storage sites are located in southwestern British Columbia. The closest storage location for industries in southwestern British Columbia (several cement manufacturers and a petroleum refinery) is approximately 600 km west in saline aquifers in southern Alberta. Data on saline aquifers in northeastern British Columbia is not publically available. One depleted gas reservoir located in northeastern British Columbia is included because of its large capacity and location (Bachu, 2006). I assume CO₂ emissions from the Fort Nelson natural gas processing plant are transported 17 km to an 88 Gt capacity oil reservoir near Clarke Lake.

A summary of cost of storage by location is shown in Table 3-2 below.
### Table 3-2  Cost of Storage by Location

<table>
<thead>
<tr>
<th>Industry</th>
<th>Storage Location</th>
<th>On or Off Shore</th>
<th>Cost ($/t)</th>
<th>Range ($/t)</th>
<th>Reference and Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depleted Gas</td>
<td>NE BC</td>
<td>On</td>
<td>2.4</td>
<td></td>
<td>Assume similar cost to Depleted gas reservoir in US (IPCC 2005)</td>
</tr>
<tr>
<td>Saline Aquifer</td>
<td>WCSB</td>
<td>On</td>
<td>1.9</td>
<td>0.66 – 3.4</td>
<td>Average of Nygaard and Lavoie 2009 and Rubin et al 2008</td>
</tr>
<tr>
<td>Deep Saline Aquifer</td>
<td>SW Ontario (Lake Erie)</td>
<td>Off</td>
<td>6.3</td>
<td></td>
<td>Shafeen et al. 2004</td>
</tr>
<tr>
<td>Depleted Oil</td>
<td>USA</td>
<td>On</td>
<td>1.6</td>
<td>0.61 – 4.8</td>
<td>IPCC (2005)</td>
</tr>
<tr>
<td>Depleted Gas</td>
<td>USA</td>
<td>On</td>
<td>2.9</td>
<td>0.61 - 15</td>
<td>IPCC (2005)</td>
</tr>
<tr>
<td>Deep Saline Aquifer</td>
<td>Atlantic Basin</td>
<td>Off</td>
<td>12.5</td>
<td></td>
<td>Conservative estimate, assume Atlantic basin is 2x SW ON</td>
</tr>
</tbody>
</table>

I determined the distance of transport from a capture site by finding the closest storage site. As EOR sites provided an economic benefit, I needed a method to assess which capture sites obtained priority to the EOR sites. To determine priority to an EOR storage location I created a set of rules, based on the priority rules used by Dooley, et al. (2004):

1. A storage site must be able to accommodate CO₂ for at least ten years.
2. The capture site with the lowest cost ($/CO₂-avoided) gets priority. Cost is based on capture cost and transport cost. This step differs from Dooley, who chose to ignore the cost of capture.

As all of the saline aquifers included in the analysis have enough storage capacity to sequester all capture emissions in the region for ten years, the priority rules were not used for saline aquifers. Once captures sites were matched with a storage site, the transport distance between the two could be calculated.

The cost of transportation depends on the mode of transport and distance to travel. If travel distance is less than 1000 km, pipelines are the most economical method of transport (IPCC, 2005). Pipeline transport is also the most widely chosen method in the CCS literature. The cost of pipeline is lower if constructed onshore versus offshore. Cost estimates for transport are based on the IPCC (2005) shown in Table 3-3 below.
Pipelines less than or equal to 100 km were assigned a cost of $2.18/tonne. Pipelines between 100 km and 200 km were assigned a cost of $3.27/tonne. Costs for 400 km and 800 km were approximated based on a quadratic equation fit to the values provided in the IPCC.

For capture sources located near offshore saline aquifers in southern Ontario and in Atlantic Canada, I assumed an additional 50 km off shore pipeline would be needed based on the methodology from Shafeen (2004). An offshore pipeline (less than 100 km) would add an additional cost of $2.18/tonne (refer to Table 3-3).

### Table 3-3 Cost of CO₂ pipeline

<table>
<thead>
<tr>
<th>Distance (km)</th>
<th>Onshore Cost ($/t-CO₂)</th>
<th>Offshore Cost ($/t-CO₂)</th>
</tr>
</thead>
<tbody>
<tr>
<td>100</td>
<td>2.18</td>
<td>2.18</td>
</tr>
<tr>
<td>200</td>
<td>3.27</td>
<td>3.27</td>
</tr>
<tr>
<td>400</td>
<td>4.69(^1)</td>
<td></td>
</tr>
<tr>
<td>800</td>
<td>8.41(^1)</td>
<td></td>
</tr>
<tr>
<td>1,000</td>
<td>10.9</td>
<td>15.26</td>
</tr>
</tbody>
</table>

*Note. Obtained from IPCC, 2005*  
\(^1\) Estimated by approximating a quadratic function based on the cost values provided by IPCC, 2005.

I assumed that each pipeline is constructed individually. However, costs can be minimized due to economies-of-scale if large pipeline networks are constructed. Ideal locations for large pipeline networks are Alberta and southern Ontario because they are areas with a high density of CO₂ sources.

### 3.3. Development of Cost Curves

I summed the capture, transport and storage costs together over each capture site to obtain an estimate of total cost for CCS. Ordering the sites' total CCS cost from lowest to highest and plotting versus cumulative annual emissions create the national cost curve.
3.4. Updating the Model with CCS Detail

CIMS originally included carbon capture costs for specific CCS technologies, but ignored transport and storage costs as well as possible economic benefits from enhanced oil recovery (EOR). I also modified how the natural gas sector in British Columbia is modeled, changed the values related to cost benefits due to economies-of-learning, and updated the costs for IGCC technology in the electricity sector.

Transport and Storage Costs

I modeled transport and storage costs similar to the carbon capture cost already existent in the model. All technologies that required the carbon capture technology (known as a service called CCS_Cost) also required the transport and storage service (CO2_Transport_Storage). I assume a capture efficiency of 90%.

In CIMS, CO₂ can be emitted from either combustion or process. If the CO₂ is captured from combustion emissions, the quantity of CO₂ captured is equal to 90% of the combustion emissions. If the CO₂ is captured from process emissions and combustion emissions, the quantity of CO₂ captured is equal to:

\[ 9 \times \{ \text{process_emissions} + 0.9 \times \text{comb_emissions} \} + 0.9 \times \text{comb_emissions} \]

The units for amount of CO₂ captured are in tonnes of CO₂ per demand unit. For example in the electricity sector the units are tonnes of CO₂ per GJ of electricity.

Transport and storage costs are based on values obtained from the CCS cost curve (presented in Section 4.1). I disaggregated the national CCS cost curve into the same seven regions as CIMS. I did not include capture costs to avoid double counting because these costs are already captured in CIMS. The price of CO₂ for EOR is also modeled separately in order to incorporate the relationship between quantity of CO₂ available for EOR and price. Consequently, the (negative) cost of EOR was not included in CO2_Transport_Storage. The average value of the transport and storage cost for each region is shown in Table 3-4. These costs are assumed to remain constant over the 50-year horizon. A more detailed description of how these values are determined is given in the results section for the cost curves (4.1).
Table 3-4  Transport and Storage Cost values for CIMS

<table>
<thead>
<tr>
<th>Province</th>
<th>Transport &amp; Storage Cost ($/t-CO2)</th>
</tr>
</thead>
<tbody>
<tr>
<td>BC</td>
<td>8.6</td>
</tr>
<tr>
<td>AB</td>
<td>5.2</td>
</tr>
<tr>
<td>SK</td>
<td>4.5</td>
</tr>
<tr>
<td>MB</td>
<td>7.6</td>
</tr>
<tr>
<td>ON</td>
<td>12</td>
</tr>
<tr>
<td>QC</td>
<td>24</td>
</tr>
<tr>
<td>ATL</td>
<td>18</td>
</tr>
</tbody>
</table>

Enhanced Oil Recovery Costs

EOR costs were included separately from transport and storage costs and only applied to sectors in British Columbia, Alberta and Saskatchewan. The relationship between CO₂ price and quantity of CO₂ sequestered through EOR is based on the 2007 Developing Council report. The dotted lines illustrated in Figure 3-6 are linear approximations of the Developing Council curves (illustrated as the solid lines). As the supply of CO₂ for EOR increases, the price for CO₂ decreases. The four shades of grey represent the different assumptions on price for a barrel of oil. The curves provided in the Developing Council report are based on total CO₂ sequestered over lifespan, stated as 30 – 40 years. To obtain annual sequestration curves, I assumed the rate of sequestration remains constant over the lifespan, and that the average lifespan is 35 years.
Figure 3-6  
**Relationship between CO$_2$ price and CO$_2$ sequestered by EOR**

In CIMS, duplicates of all CCS technologies in BC, AB, and SK were created and modified to include an option for EOR. High prices for CO$_2$-EOR (modeled as a negative cost) would decrease the life-cycle cost of the EOR technology, increasing the likelihood the technology would be chosen to meet a process demand. Note that this is the price paid for CO$_2$. This value is added as a negative to the cost of the CCS technology. If the CO$_2$-EOR price were $0$, then there would no longer be an economic benefit to sequestering in EOR sites.

To incorporate that price versus supply dynamic, CIMS was soft-linked with a simple CO$_2$-EOR program containing the linear approximated relationship from Figure 3-6. The model was run using a first estimate of the CO$_2$-EOR price curve. The total quantity per period was obtained from the CIMS model output and then entered into the CO$_2$-EOR program. If too large a quantity of CO$_2$-EOR was sequestered for the original price curve, the price was too high. The program suggested a new, lower price curve (or vice versa if the quantity is too low), which was subsequently inputted into the CIMS model. The iteration between the model and the CO$_2$-EOR program continues until they converge (within 1 decimal place) on a CO$_2$-EOR price and quantity.

**Learning Rates**

CIMS originally used a learning rate of 30% (progress ratio of 0.7) for the CO$_2$ capture technology. This value was higher than learning rates found in the literature. A McDonald and Schrattenholzer (2001) study of more than forty energy-related
technologies found that learning rates varied from -14% to 34%, with an average value of 16%. Riahi et al. (2004) used a learning rate of 13% for carbon capture technology by equating it to the learning rate found for a proxy technology—flue gas desulfurization (FGD) technology for SO₂ capture in coal-fired power plants. I assumed a learning rate of 15%.

While literature on the learning rate is prevalent, little discussion exists on the other important variable—initial cumulative production. To overcome this shortfall I assumed, based on expert opinion, the costs of CCS will decline by half in 2030 (J. Peters, personal communication, May 2012). The lower learning rate signifies that capital costs will not decrease as quickly after 2030. I calibrated the model to determine what initial cumulative production would be necessary to satisfy this assumption at a learning rate of 15%.

**Natural Gas Sector in British Columbia**

Natural Gas production in British Columbia in CIMS can be derived from conventional sources, tight gas, coal bed methane and shale gas. However, as discussed earlier, the two shale gas plays in British Columbia—Horn River and Montney—differ significantly in terms of formation CO₂. Since carbon capture is most likely to occur on plays with large formation CO₂, I chose to separate shale gas production in CIMS into Horn River production and Montney production. The costs of production for the two different reserves were calculated based on Foreman (2012) shown in Table 3-5. The operating cost values in CIMS were changed so that the life cycle cost it calculated equalled the cost provided by Foreman.

<table>
<thead>
<tr>
<th>Shale Play</th>
<th>Full Cycle Break Even</th>
<th>Operating Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>($2011US/mcfe) ($2005CD/Mm³)</td>
<td>($2005CD/10^4m³NG)</td>
</tr>
<tr>
<td>Montney</td>
<td>4.45 166</td>
<td>16.1</td>
</tr>
<tr>
<td>Horn River</td>
<td>4.75 177</td>
<td>27.3</td>
</tr>
</tbody>
</table>

*Note.* Obtained from Foreman (2010). The forecast of production required updating since shale gas production had been split into two different plays. Total natural gas forecasts remained unchanged.
calculated the percentage of production between different types of natural gas reserves from 2005 to 2020 based on Spectra Energy’s production forecast (Figure 3-7). I calculated the percentage of production from 2025 to 2050 for the various types of reserves by pro-rating original annual incremental change in production for conventional and tight natural gas. The remaining percentage of production went to shale gas production; I assumed that the percentage of shale gas production from Horn River and Montney remained consistent over the remaining 25-year time frame based on their relationship in 2020.

Figure 3-7  BC Gas Production Forecast (Bcf/d)


Electricity Sector

Costs for integrated gasification combined cycle (IGCC) technology were updated based on the Clean Power Coalition Phase III report (2010). This update resulted in a significant increase in the levelized cost of energy (LCOE) for IGCC technologies and consequently reduced their market share in Ontario, Alberta, Saskatchewan and Atlantic. This result aligns with experts who have concluded that the uptake of IGCC technology will be minimal under moderate climate policy and current natural gas and coal price forecasts (M. Jaccard, personal communication, April 2012).

3.4.1. Policy Scenarios

I used the model to simulate five different policy scenarios and a business-as-usual (BAU) scenario. The first policy is an economy-wide carbon price. The second and third policies are regulations prohibiting new electricity generation using coal without carbon capture and storage. The second policy allows new high efficiency natural gas
generation; the third policy prohibits it. The fourth policy is a regulation on the energy-related sectors and the fifth policy is a carbon price that meets the same emission reductions as the fourth policy. I only included carbon pricing and regulation policies to allow comparison between the most economically efficient policy tool (carbon price) and governments’ favoured environmental policy tool (regulation). I ignored subsidy policies, as they are an ineffective and costly climate policy tool. Finally, I focused on a few policies that target specific sectors of the economy to mimic the current federal government’s “sector by sector” approach to climate policies.

The first policy scenario, Pol1, was a carbon price applied to all sectors covered by the model (electricity generation, industry, agriculture, residential and commercial). Every tonne of CO$_2$ emitted would be charged a unit price in $/tonne of CO$_2$. I chose a carbon pricing scheme for Pol 1 to match the federal government’s greenhouse gas emission targets. The Conservative Government set emission reduction targets of 20% below 2006 levels by 2020 and 65% by 2050 (NRTEE, 2008) in the 2007 climate change plan, Turning the Corner. In 2009, the Federal Government modified the emission reduction targets to a 17% reduction from 2005 levels by 2020 under the Copenhagen Accord (Government of Canada, 2011). Long-term reduction targets were not mentioned. Pol1 policy scenario employs a carbon pricing scheme that meets an emission reduction target of 17% below 2005 levels by 2020 and 65% by 2050. CIMS generates emissions trajectories by simulating the economies response to a carbon price schedule. Iterations occurred until the desired emissions trajectory is found.

Pol2 is modeled similarly to the proposed federal electricity regulation, which prohibits new coal plants or low efficiency natural gas plants (emissions intensity greater than 0.104 t-CO2/GJ) without carbon capture after 2015. In CIMS, NGCC plants have emission intensities below the threshold and consequently are an acceptable technology post 2015. Pol3 builds upon Pol2; all natural gas plants without CCS are prohibited after 2020. Thus all new electricity generation technology after 2020 has near-zero emissions.

Pol4 is a regulation for all energy related sectors: electricity generation, petroleum crude production, petroleum-refining and natural gas production. The electricity regulations remain the same as in Pol3. In the other three sectors, all new technologies from covered processes are required to have near-zero emissions after
2020 through use of carbon capture technology, hydrogen energy or electricity. Technologies from key processes that require fossil fuels (without carbon capture) are prohibited. The covered processes are those with a technological option for CCS and include hydrogen production, upgrading, boilers, cogenerators, heaters and removal of formation emissions. Finally, **Pol 5** is a carbon pricing scheme applied to the energy related sectors that achieve the same level of emission reductions as **Pol4**. Table 3-6 is a summary of the 5 policies.

**Table 3-6 Summary of policy scenarios**

<table>
<thead>
<tr>
<th>Policy Name</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pol1</td>
<td>Carbon Price - 65% below 2005 levels in 2050</td>
</tr>
<tr>
<td>Pol2</td>
<td>Clean Electricity Standard with high efficiency natural gas</td>
</tr>
<tr>
<td>Pol3</td>
<td>Clean Electricity Standard no natural gas without CCS</td>
</tr>
<tr>
<td>Pol4</td>
<td>Clean Energy Sectors Standard</td>
</tr>
<tr>
<td>Pol5</td>
<td>Energy Sectors Price- Match Emissions of Clean Energy Sector Standard</td>
</tr>
</tbody>
</table>

### 3.4.2. Economic Impact Measures

I used two measures to compare the economic impact of the policies. The first measure is change in electricity price and the resulting change in monthly expenditure on electricity in the household. The change of electricity price varies by province, thus the regional impact of the policies can be compared. The second measure is techno-economic cost (TEC). The TEC is described as the engineers cost and includes the capital, operating and management, and energy costs (Equation 5). I used the TEC to compare the economic impacts of the policies on the energy sectors.

**Equation 5**

\[
\text{TEC} = (O&M + E) \times PF + CC \times CCF, \quad \text{where:}
\]

- O&M is Operating and maintenance cost,
- E is Energy cost,
- \(PF\) is \(PV = \frac{(1+r)^p - 1}{r(1+r)^p}\), \(r\) is discount rate, and \(p\) is years in period (5 years),
- CC is Capital cost,
- CCF is Capital cost factor, \(PF/5\).
4. Results and Analysis

The CCS cost curves presented in section 4.1 are static and illustrate the potential of CCS in Canada without consideration of policy. Dynamic results that simulate the effect of policy are presented in section 4.2.

4.1. Cost Curve Results and Analysis

The capture, transport and storage costs were compiled to produce a national CCS cost curve for Canada, as illustrated in Figure 4-1. The cost of CCS ranges from -$12/t-CO₂ for an ammonia plant located in Alberta to $235/t-CO₂ for SAGD operation in the Alberta oil sands. Approximately 65% of the emissions covered by the analysis (110 Mt, 16% of total 2009 emissions) could be captured and sequestered for a cost less than $100/t-CO₂. This result suggests that CCS could have a moderate impact on reducing Canada’s CO₂ emissions under a moderate price on carbon.

Figure 4-1 National CCS Cost Curve
Approximately 13 Mt-CO$_2$ or 2% of total 2009 emissions can be reduced for less than $30/t$-CO$_2$. This value is equivalent to British Columbia’s current carbon tax. However, BC’s current tax design excludes many low cost options such as capturing formation CO$_2$ emissions from the natural gas industries. Ignoring significant portions of emissions from the natural gas industry in BC is worrisome due to the expected growth in natural gas extraction from the Horn River reserve. If low cost CCS options are not covered by energy or climate policy, there is little incentive for the industries to adopt CCS technologies and the overall cost of the climate policy will be much greater.

While excluding coverage of low cost CCS options increases the cost of emissions reduction, including the high cost CCS options in regulation also results in significant cost increases. Applying CCS to the remaining three percent of emissions covered in this analysis dramatically increases the cost. Emissions captured from SAGD operations have nearly double the capture cost of the next most expensive option. This result suggests that a stringent regulation requiring all industries included in this analysis to implement CCS technology would be economically inefficient. However, production of the oil sands is expected to triple from 2011 to 2030 with the majority of increased supply being met by SAGD operations (CAPP, 2012, NEB). Emissions from the oil sands are predicted to increase faster than any other sector or sub-sector in Canada (Pembina, 2011). If the oil sands continue to expand at the rate forecasted, the cost of reducing emissions by CCS may become prohibitive.

I estimate that approximately 11 Mt-CO$_2$ is designated for EOR sites, predominantly in Alberta. Based on the ICO2N (2007) report (Figure 3-4) the price for that quantity of CO$_2$ would be -$30/t$-CO$_2$. If more CO$_2$ was available for EOR, the price for EOR would likely decrease. Though these results ignore the effect of policy, based on the priority rules discussed in the methodology, the results more closely resemble the effect of a carbon pricing policy. For example, if a low carbon price existed, the industries sequestering CO$_2$ in EOR sites would be dominated by low cost capture options such as those that produce hydrogen. However, if a regulation policy that targeted energy-related industries was in place, sequestering in EOR sites would be dominated by CO$_2$ captured from the electricity and petroleum crude industries.
Approximately, 50% of the emissions from the industrial sector as reported to Environment Canada (or 20% of Canada’s total emissions) are covered in this analysis by CCS technology (Table 4-1). Saskatchewan and Atlantic Canada have the largest percentage of emissions viable for the application of CCS. British Columbia and Quebec currently have the lowest potential for CCS.

Table 4-1  Comparison of Emission Sequestered as shown in Cost Curve versus total reported Industrial Emissions

<table>
<thead>
<tr>
<th></th>
<th>Total Sequestered (Mt-CO(_2))</th>
<th>Total Industrial Emissions (Mt-CO(_2))¹</th>
<th>Percentage Sequestered of Total Industry</th>
</tr>
</thead>
<tbody>
<tr>
<td>British Columbia</td>
<td>1.7</td>
<td>11</td>
<td>15%</td>
</tr>
<tr>
<td>Alberta</td>
<td>65</td>
<td>139</td>
<td>46%</td>
</tr>
<tr>
<td>Saskatchewan</td>
<td>14</td>
<td>23</td>
<td>61%</td>
</tr>
<tr>
<td>Manitoba</td>
<td>0.7</td>
<td>1.5</td>
<td>44%</td>
</tr>
<tr>
<td>Ontario</td>
<td>25</td>
<td>49</td>
<td>51%</td>
</tr>
<tr>
<td>Quebec</td>
<td>5.2</td>
<td>22</td>
<td>24%</td>
</tr>
<tr>
<td>Atlantic</td>
<td>17</td>
<td>30</td>
<td>58%</td>
</tr>
<tr>
<td>TOTAL</td>
<td><strong>129</strong></td>
<td><strong>275</strong></td>
<td><strong>47%</strong></td>
</tr>
</tbody>
</table>

¹Total Industrial Emissions are based on emissions reported under Environment Canada’s GHG reporting program.

The regional variations in capture, transport, and storage costs are presented in Table 4-2. While capture costs are dependent on industry instead of region, the table illustrates how the regional variation in industry affects the cost of capture. The capture costs represent the largest percentage of total CCS cost as well as the most varying cost (ranging from $21/t-CO\(_2\) to $227/t-CO\(_2\)).

In comparison, the transport and storage costs remain roughly constant with the exception of EOR in the western provinces. The cost of transport is marginally higher in the eastern provinces (Ontario, Quebec and the Atlantic provinces) over the western provinces (British Columbia, Alberta, Saskatchewan and Manitoba), ranging from 5.3 – 13 $/t-CO\(_2\) and 2.6 – 10.2 $/t-CO\(_2\) respectively. The cost of storage, on the other hand, is significantly higher in eastern provinces compared to the western provinces, ranging from 6.3 – 13 $/t-CO\(_2\) and -30 – 2.4 $/t-CO\(_2\) respectively.

The greater transport and storage costs in eastern Canada translate to higher average total cost for CCS in eastern Canada. Quebec and Atlantic Canada have
average CCS costs between 90 and 100 \$/t-CO_2. In western Canada, the average cost of CCS is less than \$70/t-CO_2. The lower costs in western Canada can largely be attributed to the high price of CO_2 for EOR. If the price for CO_2 decreases due to increased supply, I expect the difference in total CCS cost between eastern and western Canada to be minimal.

Table 4-2  Regional Variation in Capture, Transport and Storage Costs

<table>
<thead>
<tr>
<th>Region</th>
<th>Capture</th>
<th>Transport</th>
<th>Storage</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Average</td>
<td>Range</td>
<td>Average</td>
<td>Range</td>
</tr>
<tr>
<td>BC</td>
<td>53</td>
<td>22 - 115</td>
<td>6.7</td>
<td>2.6 - 10</td>
</tr>
<tr>
<td>AB</td>
<td>61</td>
<td>21 - 227</td>
<td>3.7</td>
<td>2.6 - 10</td>
</tr>
<tr>
<td>SK</td>
<td>62</td>
<td>21 - 115</td>
<td>2.6</td>
<td>2.6 - 2.6</td>
</tr>
<tr>
<td>MB</td>
<td>26</td>
<td>21 - 62</td>
<td>5.7</td>
<td>5.7 - 5.7</td>
</tr>
<tr>
<td>ON</td>
<td>64</td>
<td>21 - 115</td>
<td>5.7</td>
<td>5.3 - 13</td>
</tr>
<tr>
<td>QC</td>
<td>73</td>
<td>22 - 115</td>
<td>12</td>
<td>8.3 - 13</td>
</tr>
<tr>
<td>AT</td>
<td>73</td>
<td>22 - 115</td>
<td>5.5</td>
<td>5.3 - 6.6</td>
</tr>
</tbody>
</table>

The following six figures (Figure 4-2 to Figure 4-7) are disaggregated cost curves for the seven different regions used in CIMS (Saskatchewan and Manitoba combined as one). The storage, transport, capture and total costs are all provided on the figures to illustrate how the various types of costs differ across Canada.

The black solid curve, representing the largest values, is the total cost of CCS. The curve is a summation of the lower three curves. Capture is the largest contributor to total cost, denoted by a dashed, medium gray line. The two lowest costs curves are the transport cost, denoted by dashed light grey line, and the storage costs, denoted by the dotted medium grey line.
Figure 4-2  Alberta’s decomposed CCS cost curve

Figure 4-3  British Columbia’s decomposed CCS cost curve

Figure 4-4  Saskatchewan’s and Manitoba’s decomposed CCS cost curve
Figure 4-5  Ontario's decomposed CCS cost curve

Figure 4-6  Quebec's decomposed CCS cost curve

Figure 4-7  Atlantic's decomposed CCS cost curve
Alberta has the largest potential to sequester CO$_2$ (65 Mt-CO$_2$) followed by Ontario (25 Mt-CO$_2$). Emissions captured in Alberta are predominantly due to fossil fuel electricity generation (64%) and non-conventional oil extraction (27%). Both the lowest cost and highest cost CCS options are located in Alberta, ranging from ammonia production plants with EOR sequestration to capturing from the SAGD operations in the oil sands. In Ontario, the industries with the largest potential for CO$_2$ capture are fossil fuel electricity generation (48%) and iron and steel (26%).

Very little potential for CCS exists in British Columbia, Manitoba and Quebec, 7.6 Mt-CO$_2$ in total. These are also the three provinces in Canada where hydropower dominates electricity generation, not fossil fuels. Since the cost curves are only based on 2009 emissions, the curves due not incorporate British Colombia’s forecasted increase in production of unconventional national gas. The growth of the unconventional natural gas industry, especially from increased production in the Horn River Reserve, will likely increase the potential for CCS in that province.

Globally, very few large-scale CCS projects exist. As the number of international CCS projects increase, the costs of carbon capture technology are expected to decrease due to learning and experience (Li et al. 2012). Policies that target initial low cost CCS options increase the experience with CCS technology and may contribute to overall cost decreases for CCS technologies. Consequently, an effective policy should be designed to drive low cost emission reduction options to foster cost decreases due to learning.

### 4.2. Modeling Results

This section presents the simulation results from CIMS, the hybrid energy-economy model. The emission trajectories and emission reduction percentages from 2005 for the business as usual scenario and the five policies are presented in Figure 4-8 and Table 4-1. In the BAU, GHGs are expected to increase to 22% above 2005 levels by 2050. Emissions also continue to increase in the second and third policy scenarios that only target the electricity sector, albeit at a slower rate. Policy 4, (a regulation on the energy-related sectors) and Policy 5 (a carbon price matching the emissions trajectory of Policy 4) resulted in a 12% decrease from 2005 levels by 2050.
The first policy scenario requires an economy-wide carbon price in order to meet the target of 65% reduction by 2050, increasing to $500/t-CO₂ by 2050 (refer to Figure 4-9). Though the emissions reductions levels met by Policy 5 are not nearly as substantial as Policy 1, the policy also requires significant carbon prices because it is only applied to a subset of the economy.
While $500/t-\text{CO}_2$ is a high carbon price, the value is comparable to other studies. A 2011 NRTEE report suggests that in order for Canada to achieve 65% emission reductions by 2050, emission prices in 2050 would be approximately $300/t-\text{CO}_2$. The energy-modeling forum (EMF) is a group of leading energy and economic experts. In the EMF-21 study, 19 modelers forecasted the global carbon prices required to stabilize atmospheric $\text{CO}_2$ at an equilibrium temperature of 3.0°C by 2150. The carbon prices in 2050 when applied only to $\text{CO}_2$ had an average value of 720 $/t-\text{CO}_2$ (Weyant, 2006). Furthermore, high carbon prices like this may trigger macro-economic effects that a hybrid, partial equilibrium model such as CIMS ignores. These effects tend to maintain a significantly lower carbon price, albeit at a cost to the economy.

Table 4-4 shows the level of CCS adoption between 2020 and 2050. Low levels of CCS occur in the BAU scenario due to the economic incentive of enhanced oil recovery. The price for EOR ranges from approximately -$60 (negative values means provides revenue) when a negligible quantity of $\text{CO}_2$ is captured to $0$ when 27 Mt-\text{CO}_2 is captured. For all the policy scenarios the price for EOR drops to zero after 2025, because the supply of $\text{CO}_2$ available for EOR exceeds the demand. The largest levels of CCS deployment occur under the economy-wide carbon price scenario (\textit{Pol1}) and the Clean Energy Sectors Standard (\textit{Pol4}). As expected, the emission reductions from CCS in \textit{Pol4} exceed \textit{Pol5}. As a market-based policy, \textit{Pol5} provides greater flexibility in obtaining emission reductions. It allows switching to more efficient technology and targets all emissions in the energy-related sectors, not just the key processes covered by the regulation. However, the emissions captured by CCS in \textit{Pol5} are only 20% lower
than Pol4 suggesting that CCS will be a key mitigation option for the energy-related sectors.

Table 4-4  Emissions Captured by CCS (Mt-CO$_2$e)

<table>
<thead>
<tr>
<th></th>
<th>2020</th>
<th>2030</th>
<th>2040</th>
<th>2050</th>
</tr>
</thead>
<tbody>
<tr>
<td>BAU</td>
<td>11</td>
<td>16</td>
<td>20</td>
<td>25</td>
</tr>
<tr>
<td>Pol1</td>
<td>22</td>
<td>125</td>
<td>226</td>
<td>314</td>
</tr>
<tr>
<td>Carbon Price - 65%</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pol2</td>
<td>14</td>
<td>25</td>
<td>38</td>
<td>49</td>
</tr>
<tr>
<td>Clean Electricity Standard w/ NG</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pol3</td>
<td>12</td>
<td>40</td>
<td>69</td>
<td>88</td>
</tr>
<tr>
<td>Clean Electricity Standard</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pol4</td>
<td>12</td>
<td>108</td>
<td>214</td>
<td>316</td>
</tr>
<tr>
<td>Clean Energy Sectors Standard</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pol5</td>
<td>11</td>
<td>92</td>
<td>170</td>
<td>253</td>
</tr>
<tr>
<td>Energy Sectors Price- Match Pol4</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

The level of emission reductions by CCS under Pol1 and Pol4 (economy-wide carbon price and energy-sector regulation) are approximately equal. Figure 4-10 illustrates the sectors in which CCS occurs in 2050 under these two policies. The largest emission reductions occur in the petroleum crude (46% and 58% of total CCS in Pol1 and Pol4, respectively) and electricity sectors (39% and 34%). Larger quantities of CCS occur in the petroleum crude sector under the Pol4 regulation suggesting that the regulation forces some higher cost mitigation options. The opposite occurs in the electricity sector suggesting that the regulation misses some lower cost CCS mitigation options. By focusing only on the energy-related sectors, Pol4 ignores the CCS reduction potential in the ammonia, biodiesel, cement, and iron and steel sectors.
Figure 4-10  **CCS by Sector in 2050 under an economy-wide carbon price (Pol1) and Clean Energy Sector Standard (Pol4)**

Figure 4-11 illustrates the regions in which CCS occurs in 2050 under these two policies. The largest emission reductions occur in Alberta (77% and 84% of total CCS) and Ontario (14% and 8%). Nearly twice as much CCS occurs in Ontario under Pol1 than Pol4; again suggesting that the regulation misses some lower cost CCS options. Small levels of CCS occur in the other regions.

Figure 4-11  **CCS by Region in 2050, under an economy-wide carbon price (Pol1) and Clean Energy Sector Standard (Pol4)**

The effect of the five policies on electricity generation and emissions is shown in Table 4-5 and Table 4-6. The economy-wide carbon price (Pol1) results in a 43% increase in electricity generation over the BAU in 2050. The increase in electricity generation is due to significant levels of fuel switching to electricity, largely in the commercial, transportation and residential sectors. Electricity sector emission reductions in Pol1 are largely due to CCS. The electricity sector only regulations (Pol2 and Pol3)
result in a decrease in electricity generation. The increased cost of lower emission generation technology and resulting increase in electricity price would reduce the demand for electricity from other sectors. The electricity generation increases in the two energy-sector policies as a result of the CCS technology demanding additional electricity and the carbon pricing policy increasing fuel switching to electricity.

**Table 4-5**  
**Total Electricity Generation (TWh)**

<table>
<thead>
<tr>
<th></th>
<th>2020</th>
<th>2030</th>
<th>2040</th>
<th>2050</th>
</tr>
</thead>
<tbody>
<tr>
<td>BAU</td>
<td>718</td>
<td>816</td>
<td>918</td>
<td>986</td>
</tr>
<tr>
<td>Pol1</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Carbon Price - 65%</td>
<td>823</td>
<td>1,071</td>
<td>1,286</td>
<td>1,408</td>
</tr>
<tr>
<td>Pol2</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Clean Electricity Standard w/ NG</td>
<td>719</td>
<td>814</td>
<td>912</td>
<td>968</td>
</tr>
<tr>
<td>Pol3</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Clean Electricity Standard</td>
<td>718</td>
<td>808</td>
<td>901</td>
<td>952</td>
</tr>
<tr>
<td>Pol4</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Clean Energy Sectors Standard</td>
<td>718</td>
<td>817</td>
<td>926</td>
<td>993</td>
</tr>
<tr>
<td>Pol5</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Energy Sectors Price- Match Pol4</td>
<td>718</td>
<td>819</td>
<td>927</td>
<td>997</td>
</tr>
</tbody>
</table>

Prohibiting NGCC technology in Pol3 dramatically reduces the electricity sector's emissions in comparison to Pol2, which allows NGCC technology. While Pol3 and Pol4 have the same regulation on the electricity sector, Pol4 has marginally higher electricity emissions. The emissions are greater in the Pol4 regulation because the policy results in an increased demand for electricity from the other energy-related sectors.

**Table 4-6**  
**Electricity Sector Emissions (Mt-CO₂e)**

<table>
<thead>
<tr>
<th></th>
<th>2020</th>
<th>2030</th>
<th>2040</th>
<th>2050</th>
</tr>
</thead>
<tbody>
<tr>
<td>BAU</td>
<td>84</td>
<td>89</td>
<td>94</td>
<td>96</td>
</tr>
<tr>
<td>Pol1</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Carbon Price - 65%</td>
<td>69</td>
<td>44</td>
<td>28</td>
<td>20</td>
</tr>
<tr>
<td>Pol2</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Clean Electricity Standard w/ NG</td>
<td>78</td>
<td>70</td>
<td>58</td>
<td>44</td>
</tr>
<tr>
<td>Pol3</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Clean Electricity Standard</td>
<td>78</td>
<td>59</td>
<td>37</td>
<td>16</td>
</tr>
<tr>
<td>Pol4</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Clean Energy Sectors Standard</td>
<td>78</td>
<td>59</td>
<td>39</td>
<td>20</td>
</tr>
<tr>
<td>Pol5</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Energy Sectors Price- Match Pol4</td>
<td>83</td>
<td>68</td>
<td>43</td>
<td>24</td>
</tr>
</tbody>
</table>

*Pol4 and Pol5 target emission reductions in the energy-related sectors as shown in*
Table 4-7. The regulation (Pol4) has larger emission reductions in the electricity and petroleum refining sectors. The carbon pricing policy (Pol5) has larger emission reductions in the natural gas and petroleum crude sectors.

In the electricity sector, the flexibility allowed by the carbon price in Pol5 enables some emission reductions from fuel switching to renewables and nuclear. Both policies lead to significant emission reductions from CCS.

In the petroleum crude sector, nearly all of the emission reductions occur due to CCS. Pol4 has less fuel switching to electricity and other fuels than the BAU and Pol5. Overall, these changes are minimal in comparison to the emission reductions from CCS. Demand for petroleum crude is required to stay constant in all scenarios. As the results between the regulation and the carbon price are similar, the regulation is likely nearly as cost effective as the carbon price. Cost effectiveness refers to minimizing the cost required to achieve a given output, which in this case is emissions reduction.

The natural gas sector achieves more emission reductions in the carbon price (Pol5) than the regulation (Pol4), suggesting that the regulation ignores low cost emission reduction options such as energy efficiency or switching to electricity. 15% more CCS occurs in Pol5 than Pol4 implying that low cost CCS retrofit options exist.

The petroleum-refining sector has greater emission reductions and nearly doubles the CCS in Pol4 than Pol5. Both scenarios have minimal changes to output and fuel switching to electricity. These results suggest that mitigation options in the petroleum-refining sector are more expensive than in other sectors such as natural gas.
Table 4-7  GHG Emissions in Other Energy Related Sectors (Mt-CO2e)

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Petroleum Crude</td>
<td></td>
<td>143</td>
<td>130</td>
<td>143</td>
</tr>
<tr>
<td>Natural Gas</td>
<td></td>
<td>55</td>
<td>41</td>
<td>54</td>
</tr>
<tr>
<td>Petroleum Refining</td>
<td></td>
<td>22</td>
<td>16</td>
<td>22</td>
</tr>
</tbody>
</table>

Two measures are used to compare the economic impact of the policies. The first measure is change in electricity price. As the change of electricity price varies by province, the regional impact of the policies can be compared. The second measure is techno-economic cost (TEC), also referred to as the engineers cost. I use the TEC to compare the economic impacts of the policies on the energy sectors.

In the regulation scenarios, the electricity price increase is due to an increase in generation costs. In the carbon price scenarios, the revenue from the carbon price is assumed to be a recycled internally, thus the calculation for electricity price does not assume that carbon tax revenues are extracted from the sector. In CIMS, when the revenue recycling function is activated, the revenue collected from each sector due to a carbon price is returned to the same sector in a lump sum basis. Government returns the tax money collected from electricity generation to electric utilities and expects them to recycle the revenue back to customers to reduce average rates.

All of the policies have minimal impact on electricity prices in 2020; the largest impact occurs in Saskatchewan with a 2.9 ¢/kWh increase over the BAU scenario in the most stringent policy (refer to Table 4-8). By 2050, the price increase in Alberta and Saskatchewan is more significant, 6.3 and 4.9 ¢/kWh, under the economy-wide carbon
price ($Pol1$) respectively. The provinces dominated by hydroelectricity (British Columbia, Manitoba, and Quebec) show negligible impacts on electricity prices.

The economy-wide carbon price policy scenario ($Pol1$) has the most significant impact on electricity, as expected since it also produces the most dramatic emission reductions in comparison to the other four policies. The economy-wide carbon price also results in the largest increase in electricity generation, which increases investment in more costly technology. The impact of $Pol2$ and $Pol3$ on electricity price is generally similar. Saskatchewan and Ontario have a larger price increase in 2050 under $Pol3$ over $Pol2$, suggesting that prohibiting new natural gas combined cycle technology (NGCC) is more costly in those two provinces than in other regions.

The electricity price in the Atlantic region is lower than the BAU in the three regulation policies ($Pol2$, $Pol3$ and $Pol4$) due to a decrease in energy intensity of the electricity sector (from an increase in hydropower generation over fossil fuel generation). This suggests that the regulations could provide cost savings to household in Atlantic Canada.

A counter-intuitive result was that the electricity price increase in Alberta and Saskatchewan was greater under the energy-related carbon price ($Pol5$) than under the energy-related regulation ($Pol4$). More pulverized coal technology with CCS occurs in the regulation than the carbon price, whereas more NGCC with CCS occurs in the carbon price. The life cycle cost of NGCC with CCS is 50% larger than pulverized coal with CCS. However, when a carbon price of $350/t-CO_2$ is applied the life cycle cost is only 15% larger. The smaller price difference between the two technologies allows the NGCC to obtain greater market share in the carbon price scenario. Consequently, the larger levels of the more costly NGCC with CCS technology results in a higher electricity increase under the carbon price than under the regulation.
<table>
<thead>
<tr>
<th>Year</th>
<th>Policy</th>
<th>BC</th>
<th>AB</th>
<th>SK</th>
<th>MB</th>
<th>ON</th>
<th>QC</th>
<th>AT</th>
</tr>
</thead>
<tbody>
<tr>
<td>2020</td>
<td>Pol1 - All$</td>
<td>1.1</td>
<td>1.4</td>
<td>2.9</td>
<td>0.2</td>
<td>0.8</td>
<td>0.2</td>
<td>0.7</td>
</tr>
<tr>
<td></td>
<td>Pol2 - ElecReg</td>
<td>0.0</td>
<td>0.2</td>
<td>1.2</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td></td>
<td>Pol3 - ElecReg no NG</td>
<td>0.0</td>
<td>0.1</td>
<td>1.3</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td></td>
<td>Pol4 - EnrgReg</td>
<td>0.0</td>
<td>0.1</td>
<td>1.3</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td></td>
<td>Pol5 - Enrg$</td>
<td>0.0</td>
<td>-0.1</td>
<td>2.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>2050</td>
<td>Pol1 - All$</td>
<td>1.1</td>
<td>6.3</td>
<td>4.9</td>
<td>0.7</td>
<td>1.3</td>
<td>0.4</td>
<td>1.4</td>
</tr>
<tr>
<td></td>
<td>Pol2 - ElecReg</td>
<td>0.0</td>
<td>3.3</td>
<td>3.1</td>
<td>0.1</td>
<td>0.0</td>
<td>0.0</td>
<td>-0.1</td>
</tr>
<tr>
<td></td>
<td>Pol3 - ElecReg no NG</td>
<td>-0.1</td>
<td>3.6</td>
<td>4.3</td>
<td>0.1</td>
<td>0.6</td>
<td>0.0</td>
<td>-0.2</td>
</tr>
<tr>
<td></td>
<td>Pol4 - EnrgReg</td>
<td>-0.1</td>
<td>3.1</td>
<td>3.8</td>
<td>0.1</td>
<td>0.5</td>
<td>0.0</td>
<td>-0.2</td>
</tr>
<tr>
<td></td>
<td>Pol5 - Enrg$</td>
<td>0.0</td>
<td>4.3</td>
<td>4.5</td>
<td>0.1</td>
<td>0.4</td>
<td>0.0</td>
<td>0.0</td>
</tr>
</tbody>
</table>

The effect of electricity price increases on household electricity expenditures is presented in Table 4-9. The electricity price change is multiplied by the provincial average monthly household electricity use (Statistics Canada, 2007). While Alberta and Saskatchewan have the highest electricity price increases, these provinces also have the lowest average consumption of electricity since most of their household energy use is from natural gas. Though lower average consumption reduces the impact of increased electricity prices, it still results in a 70% and 22% increases in electricity expenditures in Pol1 over the BAU scenario in Alberta and Saskatchewan respectively.

Overall the comparative impact between provinces of the policies is similar. Pol4 has a lower impact on Alberta and Saskatchewan than Pol5 even though both achieve the same overall emissions reductions.
Table 4-9  Change in Monthly Electricity Expenditure for Average Household in 2020 and 2050 ($/household/month)

<table>
<thead>
<tr>
<th></th>
<th>BC</th>
<th>AB</th>
<th>SK</th>
<th>MB</th>
<th>ON</th>
<th>QC</th>
<th>AT</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>2020</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pol1 – All$</td>
<td>9</td>
<td>8</td>
<td>20</td>
<td>2</td>
<td>6</td>
<td>2</td>
<td>7</td>
</tr>
<tr>
<td>Pol2 - ElecReg</td>
<td>0</td>
<td>1</td>
<td>8</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Pol3 – ElecReg no NG</td>
<td>0</td>
<td>1</td>
<td>9</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Pol4 - EnrgReg</td>
<td>0</td>
<td>1</td>
<td>9</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Pol5 – Enrg$</td>
<td>0</td>
<td>0</td>
<td>14</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td><strong>2050</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pol1 – All$</td>
<td>9</td>
<td>38</td>
<td>34</td>
<td>7</td>
<td>9</td>
<td>5</td>
<td>15</td>
</tr>
<tr>
<td>Pol2 - ElecReg</td>
<td>0</td>
<td>20</td>
<td>21</td>
<td>1</td>
<td>0</td>
<td>0</td>
<td>-1</td>
</tr>
<tr>
<td>Pol3 – ElecReg no NG</td>
<td>-1</td>
<td>22</td>
<td>30</td>
<td>1</td>
<td>4</td>
<td>0</td>
<td>-2</td>
</tr>
<tr>
<td>Pol4 - EnrgReg</td>
<td>-1</td>
<td>19</td>
<td>26</td>
<td>1</td>
<td>3</td>
<td>0</td>
<td>-2</td>
</tr>
<tr>
<td>Pol5 – Enrg$</td>
<td>0</td>
<td>26</td>
<td>31</td>
<td>1</td>
<td>3</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

**Note.** Average electricity consumption for households by province is obtained from Statistics Canada (2007).

The second measure for cost comparison is the techno-economic cost, which is provided Table 4-10. The table presents the policies’ TEC for the individual energy related sectors as well as the summation of the TEC for energy-related sectors and the full economy.

The largest TEC in the electricity sector occurs under the economy-wide carbon price (Pol1). Significant levels of electrification occur under the economy-wide carbon pricing resulting in a 43% increase in electricity generation by 2050 over the BAU scenario. Increasing electricity generation requires an increase in capital, operating and management, and energy costs, resulting in a large TEC value. While Pol1 has the largest TEC value in the electricity sector, it also has the lowest economy-wide TEC. The large negative TEC is due to significant savings in the residential, transportation and commercial sectors. These sectors do not use CCS to achieve emission reductions. Thus, a policy with dramatic emission reductions can result in cost savings as denoted by the TEC over the BAU scenario. However, the TEC ignores intangible costs such as lost consumer welfare due to quality differences or higher financial risks. TEC cost savings in the residential sector occur because the policy induces people to drive smaller cars or ride transit. While these alternatives cost less, the person may prefer to
drive a larger car, thus they experience a personal welfare loss. Consequently, the TEC can provide a misleading sense of the cost of a policy because it ignores welfare losses.

As predicted, the electricity sector’s TEC was larger in the more restrictive regulation, Pol3, than Pol2. Typically, cost of a policy increases as flexibility in meeting the goal decreases. Prohibiting new NGCC technology would require investment in more costly technology such as CCS, resulting in a larger TEC.

A carbon price is expected to obtain a lower TEC than a regulation with the same emission reduction trajectory. Since the main emission reduction option for the energy-related sector is CCS, the TECs between Pol4 and Pol5 are expected to be similar. As anticipated, the TEC in the electricity, natural gas and petroleum refining sectors is marginally higher under the regulation than the carbon price. However, the petroleum crude sector’s TEC is approximately 25% larger under the carbon price than that achieved by regulation. Significantly more CCS is forced to occur in 2025 under the carbon price than the regulation, because carbon-intensive technologies are retired or retrofitted prior to their end of life. The regulation only requires CCS in new technologies after 2020 and does not force retrofits of older technologies. After 2025 more CCS occurs under the regulation. The TEC values reported are discounted to 2012. Thus costs that occur earlier have a much larger value than costs discounted over thirty years. The larger TEC value under the carbon price can largely be attributed to the considerable capital cost investment in CCS technology occurring 2025.

**Table 4-10  TEC, discounted to 2012 (Million $)**

<table>
<thead>
<tr>
<th></th>
<th>Electricity</th>
<th>Petroleum Crude</th>
<th>Natural Gas</th>
<th>Petroleum Refining</th>
<th>Total Energy</th>
<th>Total Economy</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pol1 - All$</td>
<td>166,161</td>
<td>14,642</td>
<td>2,845</td>
<td>-5,453</td>
<td>178,195</td>
<td>-158,044</td>
</tr>
<tr>
<td>Pol2 - ElecReg</td>
<td>2,152</td>
<td>296</td>
<td>403</td>
<td>-11</td>
<td>2,841</td>
<td>3,674</td>
</tr>
<tr>
<td>Pol3 - ElecReg no NG</td>
<td>3,533</td>
<td>620</td>
<td>649</td>
<td>-139</td>
<td>4,663</td>
<td>-906</td>
</tr>
<tr>
<td>Pol4 - EnrgReg</td>
<td>8,649</td>
<td>13,252</td>
<td>1,211</td>
<td>2,202</td>
<td>25,314</td>
<td>7,525</td>
</tr>
<tr>
<td>Pol5 - Enrg$</td>
<td>7,101</td>
<td>16,273</td>
<td>1,131</td>
<td>743</td>
<td>25,248</td>
<td>20,865</td>
</tr>
</tbody>
</table>

The TEC can be split into two effects: the cumulative cost of production effect and the cumulative demand effect. The cumulative cost of production effect is equal to the output of the policy times the difference in unit cost between the policy and BAU. The
cumulative demand effect is the unit cost of the BAU multiplied by the difference in output between the policy and BAU. By separating the two effects, you can determine whether the changes in the TEC are due to increasing cost of production (investing in more capital intensive technology such as CCS) or due to changes in demand (for example increased demand for electricity). The values for these two effects on the energy-related sectors are shown in Table 4-11 and Table 4-12.

The cumulative cost of production effect is generally positive under the five policies, particularly in the petroleum crude and electricity sectors. Less emission intensive technology in those sectors tends to be more capital expensive or has increased energy costs due to the energy penalty in CCS.

<table>
<thead>
<tr>
<th>Table 4-11</th>
<th>Cumulative Cost of Production Effect, discounted to 2012 (Million $)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Electricity</td>
</tr>
<tr>
<td>Pol1 – All$</td>
<td>115,687</td>
</tr>
<tr>
<td>Pol2 - ElecReg</td>
<td>2,570</td>
</tr>
<tr>
<td>Pol3 – ElecReg no NG</td>
<td>4,892</td>
</tr>
<tr>
<td>Pol4 - EnrgReg</td>
<td>8,234</td>
</tr>
<tr>
<td>Pol5 – Enrg$</td>
<td>6,436</td>
</tr>
</tbody>
</table>

The three policies that result in an increase in electricity generation over the BAU have positive electricity demand effects (refer to Table 4-5). Conversely, both Pol2 and Pol3 (the electricity regulations) result in decreases in electricity generation from the BAU, revealed as negative values in the cumulative demand effect. While Pol2 and Pol3 are both regulations on only the electricity sector, the regulations affect other sectors. Both the petroleum crude and natural gas sector have a positive TEC, albeit less than in the other scenarios. The increase in TEC in both sectors is due to an increase in capital costs over the BAU scenario. The regulations have no effect on the energy or emissions intensity of crude production, but increase the cost of production. The natural gas sector’s energy costs are higher over the BAU scenario.

The three regulations (Pol2, Pol3, and Pol4) produce no demand effect on the natural gas and petroleum crude sector, due to constraints placed on the model. All five policies result in a decrease in output in the petroleum-refining sector. The five policies
also result in an overall negative cumulative demand effect for the entire economy. Most sectors have a small reduction in output under the five policies simulated, resulting in an overall negative cumulative demand effect. The decrease in demand across the economy could be attributed to the increases in electricity prices under all policy scenarios.

Table 4-12 Cumulative Demand Effect, discounted to 2012 (Million $)

<table>
<thead>
<tr>
<th>Policy</th>
<th>Electricity</th>
<th>Petroleum Crude</th>
<th>Natural Gas</th>
<th>Petroleum Refining</th>
<th>Total Energy</th>
<th>Total Economy</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pol1 – All$</td>
<td>50,474</td>
<td>0</td>
<td>-461</td>
<td>-7,584</td>
<td>42,429</td>
<td>-153,095</td>
</tr>
<tr>
<td>Pol2 - ElecReg</td>
<td>-418</td>
<td>0</td>
<td>0</td>
<td>-17</td>
<td>-435</td>
<td>-1,452</td>
</tr>
<tr>
<td>Pol3 – ElecReg no NG</td>
<td>-1,359</td>
<td>0</td>
<td>0</td>
<td>-124</td>
<td>-1,484</td>
<td>-11,851</td>
</tr>
<tr>
<td>Pol4 - EnrgReg</td>
<td>415</td>
<td>0</td>
<td>0</td>
<td>-280</td>
<td>135</td>
<td>-20,604</td>
</tr>
<tr>
<td>Pol5 – Enrg$</td>
<td>665</td>
<td>0</td>
<td>-14</td>
<td>-93</td>
<td>557</td>
<td>-7,118</td>
</tr>
</tbody>
</table>

4.3. Policy Implications

Typically regulations are more costly for a given level of emissions reduction because they do not optimally exploit all significant pollution reduction options and ignore that abatement costs likely differ across firms. However, a well-designed regulation may be nearly as economically efficient as a carbon pricing policy as demonstrated by this study’s results. Policy 4, a regulation on the energy-related sectors, resulted in a marginally larger TEC for the same level of emission reduction as Policy 5, a carbon price on the energy-related sectors.

While my study suggests that regulations may be nearly as economically efficient as carbon pricing, a caveat to these results should be considered. CIMS may overestimate the cost of a carbon pricing policy because the model may not detect other potential benefits. Carbon pricing policies, unlike technology-mandated regulations, reward innovation. This benefit is not fully characterized because CIMS can only partially simulate technology innovation. Furthermore, carbon pricing policies reward any emission reduction action a firm performs, including housekeeping actions too refined for a model like CIMS. As CIMS only partially represents technology innovation and
abatement options for a given firm, carbon pricing policies likely have lower abatement costs than the model suggests.

While a regulation may be nearly as economically efficient as a sector specific carbon price, this is likely not the case when comparing a regulation with an economy-wide carbon price. A regulation that reduces the emission intensity of specific industries by prohibiting technology will miss alternative options for cost savings than an economy-wide carbon price. An economy-wide carbon price allows for emission reduction in the transportation, commercial and residential sectors that result in a reduction in TEC.

Governments find it difficult to implement carbon prices, especially under the current political climate. The current federal government’s approach to climate policies has been to discuss but not yet implement sector specific regulations. Consequently, a potentially helpful role of the policy analyst is to design effective regulations for policy makers that minimize the differences in economic efficiency between carbon prices and regulations.
5. Conclusion

5.1. Summary of Key Findings

In this research I determined how the costs of CCS vary by region, by industry, and by cumulative deployment. There are three objectives of this research: to determine how CCS costs vary by region and by cumulative sequestration, to develop CCS supply cost curves for Canada, and to investigate the potential impacts of climate policy on emission reductions, the economy, and CCS deployment using an energy-economy model. I will now summarize the key findings with respect to the research questions posed in Section 2.9.

Research questions:

1. How do the costs of CCS differ in Canada regionally?

The cost of transport is on average double in the eastern provinces (Ontario, Quebec and the Atlantic provinces) than the western provinces (British Columbia, Alberta, Saskatchewan and Manitoba): 7.8 versus 4.7 $/t-CO₂ respectively. The cost of storage is significantly higher in eastern provinces over the western provinces: -0.7 versus 10 $/t-CO₂ respectively. The access to enhanced oil recovery in western Canada allows storage to provide an economic benefit.

The larger transport and storage costs in eastern Canada translate to higher average total cost for CCS in eastern Canada as well. Quebec and Atlantic Canada have average CCS costs between 90 and 100 $/t-CO₂. In western Canada, the average cost of CCS is less than $70/t-CO₂. The lower costs in western Canada can largely be attributed to the high price of CO₂ for EOR. If the price for CO₂ decreases due to increased supply, I expect the difference in total CCS cost between eastern and western Canada to be minimal.
2. How do the costs of CCS increase as cumulative sequestration of CCS increases?

The cost of CCS varies by cumulative sequestration due to two factors: the effect of CO$_2$ supply on EOR price and the effect of learning. When negligible quantities of CO$_2$ are captured, the price of CO$_2$ for EOR is approximately -$60 (negative values means provides revenue). The price of CO$_2$ for EOR will fall toward $0 as we capture approximately 30 Mt-CO$_2$. All of the policy scenarios modeled in CIMS found that the price of CO$_2$ for EOR drops to zero after 2025, because the supply of CO$_2$ available for EOR exceeds the demand. While cumulative sequestration of CO$_2$ causes the cost of storage to increase from diminishing EOR revenue, cumulative sequestration causes the price of the capture technology to decrease due to economies-of-learning. I used a learning rate of 15%, which results in a 50% decrease in capture technology cost by 2030, and a 62% decrease by 2050.

3. What are the potential economic and environmental impacts of various climate change policies in Canada, regionally and sectorally?

*Economy-wide Carbon Price (Pol1):* In order to achieve emission reductions of 65% below 2005 levels by 2050, a carbon price that increases to $500/t-CO$_2$ may be required. While Pol1 has the highest TEC value in the electricity sector, it has the lowest economy-wide TEC. Significant savings in the residential, transportation and commercial sectors contribute to the negative TEC. Thus, a policy with dramatic emission reductions can result in cost savings over the BAU scenario. The electricity price increase in 2050 is most significant in Alberta and Saskatchewan, with an additional 6.3 and 4.9 ¢/kWh, respectively. The electricity price increase in the carbon pricing scenarios is due to the increased cost of generation. The carbon price is not reflected in the electricity price because the revenue is returned to the electric utilities. The provinces dominated by hydroelectricity (British Columbia, Manitoba, and Quebec) show negligible impacts on electricity prices.

*Electricity Sector Regulations (Pol2 and Pol3):* The difference between the two regulations is that Pol2 allowed new NGCC technology, whereas Pol3 prohibited it.
emissions increased 16% in Pol2 and 13% in Pol3 by 2050 over 2005 levels, thus increased at a slower rate than under business-as-usual. Emissions in the electricity sector in 2050 were one half of the BAU in Pol2 and one fifth of the BAU in Pol3. The emissions in the electricity sector are significantly lower under Pol3 than Pol2 because Pol3 prohibits new NGCC technology, forcing more CCS. The increase in electricity price was similar to Pol4 and Pol5, with the largest price increase occurring in Alberta and Saskatchewan, ranging from 3.1 to 4.3 ¢/kwh. As expected, the policies with the least effect on emissions also have the least effect on the TEC. The electricity sector’s TEC is 65% larger under the more restrictive regulation (Pol3) than Pol2.

Energy-sector policies (Pol4, a regulation and Pol5, a carbon price): The energy-sector policies resulted in a 10% decrease in emissions from 2005 levels by 2050. The overall effect on electricity price was marginally lower than the economy-wide carbon price, while achieving significantly less emission reductions than the economy-wide carbon prices. The energy-sector TEC is higher in the energy-sector policies than the electricity-sector policies, but significantly lower than the economy-wide carbon price. The electricity and petroleum crude sectors are most adversely affected by both energy-sector policies in terms of TEC. The differences between the two energy-sector policies are discussed following Question 5.

4. What levels of CCS deployment can be expected under various climate change policies in Canada?

The largest levels of CCS deployment occur under the economy-wide carbon price scenario (Pol1), 315 Mt-CO₂ and the Clean Energy Sectors Standard (Pol4), 305 Mt-CO₂ in 2050. More than 85% of the emission reductions due to CCS occur in the petroleum crude and electricity sectors under these two policies. The emissions captured by CCS is in Pol5 are 23% lower than Pol4 in 2050 suggesting that while CCS is a key mitigation option for the energy-related sectors, less expensive options exist that achieve a similar emissions reduction. The two regulations applied only to the electricity sector (Pol2 and Pol3) obtain significantly lower levels of CCS deployment. The more stringent of the two policies, which forbids NGCC technology, achieves nearly double the levels of CCS in 2050, but 3.5 times less than the economy-wide carbon price.
5. **What is the economic impact of applying CCS regulation policies that only target specific sectors versus a carbon price?**

My results showed that a well-designed regulation targeting the energy-related sectors could be nearly as economically efficient as a carbon price on the same sectors. The techno-economic cost of the energy-related sectors was only 13% higher under the regulation than the carbon price. The regulation is most costly on the petroleum refining sector as it results in a tripling in TEC for that sector, suggesting that a regulation forcing carbon capture and storage performs poorly in terms of economic efficiency. The electricity, natural gas and petroleum refining sectors have lower TECs in the carbon price policy, but the petroleum crude sector had a lower TEC in the regulation. This result suggests that the petroleum crude is bearing a larger share of the economic impact of the carbon price than the other three energy-related sectors.

The effect of the two policies on electricity price was less straightforward than the effect on the TEC. The electricity price increase in Alberta and Saskatchewan was greater under the energy-related carbon price (Pol5) than under the energy-related regulation (Pol4). The reason for this result was that more pulverized coal technology with CCS occurs in the regulation than the carbon price, whereas more NGCC with CCS occurs in the carbon price. Consequently, the larger levels of the more costly NGCC with CCS technology results in a higher electricity increase under the carbon price than the regulation.

Although both the regulation and the carbon price achieve the same levels of emission reductions and the overall economic differences are small, the costs of the policies are distributed differently. While the regulation is marginally more costly on the energy-sectors as a whole, it may prove advantageous in terms of equity because it alleviates some of the economic pressure on the petroleum crude sector. Furthermore, the regulation also has lower impact on Alberta’s and Saskatchewan’s electricity price. Alberta, Saskatchewan and the petroleum crude sector are expected to be the regions and sector most negatively impacted by climate policies. Thus, by minimizing the negative economic impacts, the regulation may prove to be more equitable than the carbon price. However, a carbon price enables government to recycle the carbon tax revenue in a variety of allocation methods, affecting the equitability of a policy. Two
common definitions of equitability are the “polluter-pays” and “equal-cost”. Polluter-pays suggest that those producing the largest levels of pollution should bear the largest cost of reduction. Equal-cost suggests that individuals or regions should bear similar costs to reduce emissions, regardless of their emissions intensity. A C.D. Howe report found that carbon pricing policy could be designed to achieve equitability in terms of polluter-pays or equal-cost (Peters, 2010). As both the carbon tax and regulation policies analyzed in this study result in similar levels of environmental effectiveness and can be designed to minimize the cost-burden on the most negatively impacted sectors, perhaps the choice of policy depends on political feasibility.

5.2. Limitation and Key Modeling Challenges

Transport and storage costs (excluding EOR) are assumed to be region specific and remain constant over the 50 year time frame. The oil and gas industry has had considerable experience transporting gases in pipelines as well as experience sequestering gases through acid-gas injection projects. Thus the unit cost is not expected to decrease substantially due to learning or experience. Conversely, costs are expected to increase due to decreasing quality of storage sites. More favourable storage sites will likely be utilized first. As the favourable sites reach capacity sequestration may be required in less desirable sites, thus increasing the cost of sequestration. This relationship is not included in the model because CIMS currently does not have the capability of increasing costs in relation to increasing production (cumulative sequestration of CO$_2$).

For example, while Ontario has a large concentration of CO$_2$ capture sites, the province is limited in local capacity to sequester CO$_2$. The two saline aquifers in the province have combined capacity of 730 Mt. Under the economy-wide carbon price scenario, Ontario exhausts its local storage capacity by 2043. If Ontario relies heavily on CCS for emissions reductions, the province will likely eventually be required to store CO$_2$ in the neighbouring states. Transporting CO$_2$ into the United States would require cross-border trade agreements and consequently increase the cost and uncertainty. The increasing costs related to increases cumulative quantity of CO$_2$ sequestered are not included in CIMS.
To overcome this problem for EOR, a simple program exterior to the model was created. Iterations between CIMS and the exterior program were run until the programs converged. This process is cumbersome, and would not be a reasonable method if it had to be applied to a number a different cost increasing issues.

5.3. Recommendations for Future Research

*Obtain regionally representative behavioural parameters for CCS:* Costs of CCS may vary with government and industry policy due to public education and involvement in the decision making process. These costs can include the risk and uncertainty of the project, largely affected by public opinion of CCS. Depending on the role of CCS actors at the local and provincial level, public opinions on CCS could vary significantly by region in Canada.

*Upgrade transport costs:* The cost of transport could be decreased significantly if scenarios with significant CCS deployment had the option for a large pipeline network, especially in Alberta and Ontario.

*Improve the methods for incorporating increasing costs in CIMS:* As discussed in section 5.2, an improved method is needed to model cost increases due to increasing cumulative sequestration.

*Include relationship between EOR cost and the price of oil:* The value for EOR is highly dependent on the cost of oil. If the price of oil is low, EOR will be less economical. If significant variation in oil price is expected to occur in a BAU or policy scenario, this relationship should be included in the EOR program. The current EOR program can accommodate an oil price that is exogenously set (determined outside of both the CIMS model and the EOR program). However, if the price of oil is dependent on EOR dynamics or other variables endogenous to CIMS, an improved EOR program is recommended.

*Perform a detailed sensitivity analysis:* I recommend performing a detailed sensitivity analysis to test key areas of uncertainty. Sensitivity analysis varies input parameters to evaluate impact on model output, thus increasing the
transparency of the model’s limitations. As shown in the literature review of industry capture cost (Appendix A), significant uncertainty exists in the cost for capturing CO₂. Thus, I recommend performing a sensitivity analysis on the capture cost input parameters.

*Develop Renewable Supply Cost Curves:* Like the CCS supply cost curve, a renewable supply cost curve provides policy makers with a sense of the cost of scaling up renewable energy technologies. The renewable and CCS cost curves could be used to determine levels of scalability of renewables and CCS under various levels of abatement cost. However, there is significant uncertainty with the cost of renewables. Since generating electricity from renewables is generally intermittent, systems for energy storage are required, resulting in significant variability of cost estimates. An energy-economy model, such as CIMS, could be used to simulate what scale and type of abatement occurs under differing conditions.
References


Hicks, J.R. (1932) *The Theory of Wages*.


Pennsylvania, for the Oil, Gas and Energy Branch, Environment Canada, Ottawa, Ontario.


Appendices
## Appendix A.

### Literature Review of CO₂ Capture Cost by Industry

**Table A-1** Literature Review of Carbon Capture Technology for various Industrial Sectors ($2005$ CDN/t-CO₂ avoided)

<table>
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<td>6.9 - 34</td>
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<td>25</td>
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</table>

Note.  
1: IPCC costs originally in 2005 USD.  
2: Rubin et al. costs originally in 2005 USD.  
3: Davison costs originally in 2005 USD. 90% emissions captured, but emissions rates per MWh are reduced by only 87-88%.  
4: David and Herzog assumed cost year is 2000 USD. PC and NGCC use MEA scrubbing of flue gas, IGCC uses more energy efficient scrubbing processes involving physical absorption to capture CO2 from the high pressure synthesis gas.  
5: Hamilton et al. costs originally in 2007 USD.  
6: MIT costs originally in 2005 USD.  
7: NETL costs originally in 2006 USD. Capture efficiencies of subcritical unit is 85.3% and supercritical is 85.7%. Study assumed a capacity factor of 85%.  
8: EPRI costs originally in 2006 USD. Capture efficiencies assumed in study to be 85%. Study assumed a capacity factor of 80%.  
9: SFA costs originally in 2006 USD. Capture efficiencies assumed in study to be 87.7%. Study assumed a capacity factor of 85%.  
10: IEA costs originally in 2010 USD. Capture efficiencies assumed in study to be a minimum of 80% and a minimum capacity of 300 MW.  
11: Global CCS Institute costs originally in 2010 USD.
Appendix B.

Ammonia Production

Table B-1 Estimating Emissions from Hydrogen Production in Ammonia manufacturing

<table>
<thead>
<tr>
<th></th>
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<tr>
<td>(10⁶ x t-NH₃)¹</td>
<td>(10⁶ x t-NH₃)²</td>
<td>(10⁶ x t-CO₂)³</td>
<td>(10⁶ x t-CO₂)⁴</td>
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<td>Redwater</td>
<td>950</td>
<td>835</td>
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<td>Medicine Hat</td>
<td>1,060</td>
<td>932</td>
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<td>409</td>
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<td>Belle Plaine</td>
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<td>Brandon</td>
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<tr>
<td>Courtright</td>
<td>412</td>
<td>362</td>
<td>565</td>
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</table>

Note. ¹ Data obtained from NRCan (2008).
² Estimated by multiplying the 2000-2002 production data in Column 1 by the percentage change in total production between 2009 and the average of 2000-2002. The International Fertilizer Industry Association provides statistics on North American ammonia production from 1999 – 2010. I assumed that the change in production in North America was reflective of Canada, and the individual ammonia producing sites.
³ To estimate CO₂ emissions from hydrogen production used in ammonia manufacturing I multiplied the estimated Ammonia production (column 2) by the emission factor (EC 2010; IPCC 1996).
⁴ The emissions reported under Environment Canada’s greenhouse gas reporting program for 2009 are presented in column 4 for comparative purposes. The values between column 3 and 4 are not consistent likely because many of the sites already capture part or all of the process-generated CO₂ for urea production (NRCan, 2008).
Appendix C.

Oil Sands Hydrogen Production

Table C-1  Key Parameters on Oil Sands Hydrogen Production

<table>
<thead>
<tr>
<th>Site</th>
<th>Q Production Rate of SCO [10^3 bbl/d]</th>
<th>El per h GHG Emission Intensity of H₂ [CO₂/h]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Syncrude (A1)</td>
<td>232</td>
<td>281</td>
</tr>
<tr>
<td>Suncor (A2)</td>
<td>213</td>
<td>233</td>
</tr>
<tr>
<td>Shell-Albian (A3)</td>
<td>93.8</td>
<td>169</td>
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</table>

Note.  Adapted from Ordicia-Garcia (2007).

To determine the GHG emissions intensity of hydrogen production per volume of SCO produced for each producer (EI per m³) I used the equation below.

**Equation 6**

\[
EI \text{ per m}^3 = EI \text{ per h} / (Q \times 1000) \times (24 \text{ h} / \text{d}) \times (6.29 \text{ bbl} / \text{m}^3),
\]

where:

- \(EI \text{ per h}\) is GHG emissions intensity of \(H_2\) [CO₂/h],
- \(Q\) is production rate [10^3 bbl/d].

I calculated the annual process GHG emissions from hydrogen production by multiplying the Emissions Intensity of \(H_2\) production per m³ of SCO by the annual production of synthetic crude oil. The total annual GHG emissions associated with hydrogen production for the three producers is 8 Mt (Table C-2)

Table C-2  Annual GHG Emissions from Hydrogen Production from 3 SCO Producers

<table>
<thead>
<tr>
<th>Site</th>
<th>Synthetic Crude Oil Production [10^6 m³ SCO/y]</th>
<th>GHG Emissions intensity of H₂ [t CO₂/10^6 m³ SCO]</th>
<th>Annual GHG Emission [Mt CO₂/y]</th>
</tr>
</thead>
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<tr>
<td>Syncrude (A1)</td>
<td>16.7</td>
<td>0.18</td>
<td>3.06</td>
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<td>Suncor (A2)</td>
<td>16.6</td>
<td>0.17</td>
<td>2.74</td>
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<tr>
<td>Shell-Albian (A3)</td>
<td>8.06</td>
<td>0.27</td>
<td>2.19</td>
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</table>

Note. Assumptions: 6.29 barrels of oil = 1 m³ of oil (Alberta Chamber of Resources, 2004)